CHAPTER I

APPLICATION OF THE ASME CODE

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APPLICATION OF THE ASME CODE

The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Division 1, Sections III (design) and XI (inservice inspection requirements) were developed and are revised periodically by industry code committees composed of representatives of utilities, reactor designers, architect-engineers, component manufacturers, insurance companies, the U.S. Nuclear Regulatory Commission (NRC), and others. In 1971, the Atomic Energy Commission (AEC), the predecessor of the NRC, incorporated the ASME Boiler and Pressure Vessel Code into the regulations in 10 CFR 50.55a through issuance of the Federal Register Notice (FRN) for the final rule (36 FR 11,423 [June 12, 1971]).

The Statements of Consideration (SOCs) for the initial issuance of 10 CFR 50.55a provide the bases for AEC's endorsement and use of the ASME Code:

> "It has been generally recognized that, for boiling and pressurized water-cooled reactors, pressure vessels, piping, pumps, and valves which are part of the reactor coolant pressure boundary should, as a minimum, be designed, fabricated, inspected, and tested in accordance with the requirements of the applicable American Society of Mechanical Engineers (ASME) codes in effect at the time the equipment is purchased[.]"
>
> "Because of the safety significance of uniform early compliance by the nuclear industry with the requirements of these ASME codes and published code revisions, the Commission has adopted the following amendments to Part 50 and 115, which require that certain components and systems of water-cooled reactors important to safety comply with these codes and appropriate revisions to the codes at the earliest feasible time."
>
> "Compliance with the provisions of the amendments and the referenced codes is intended to insure a basic, sound quality level."

These ASME Code sections are based on the collective engineering judgment of the code committees and document the conditions that must be monitored, the inspection techniques to identify those conditions, the frequency of the inspections, and the acceptance criteria that the inspections results must meet in order to assure the integrity of the structures and components considered in the code. The NRC has accepted this engineering judgment by endorsing the use of selected sections of the ASME Code, as incorporated in 10 CFR 50.55a.

In addition, the NRC periodically amends 10 CFR 50.55a and issues FRNs about this rule in order to endorse, by reference, newer editions and ASME Code Addenda subject to the modifications and limitations identified in 10 CFR 50.55a. At the time of this Standard Review Plan for License Renewal (SRP-LR) (NUREG-1800) and GALL Report (NUREG-1801) update, the most recent editions of the ASME Code Sections III and XI were endorsed in 73 FR 52730-52750 (September 10, 2008). As stated in 65 FR 53050 (August 31, 2000):

> "To ensure that the GALL report conclusions will remain valid when future editions of the ASME Code are incorporated into the NRC regulations by the 10 CFR 50.55a rulemaking, the staff will perform an evaluation of these later editions for their adequacy for license renewal using the 10-

element program evaluation described in the GALL Report as part of the 10 CFR 50.55a rulemaking."

The staff will document this evaluation in the SOC accompanying future 10 CFR 50.55a amendments, which will be published in a FRN.

To aid applicants in the development of their license renewal applications, the staff has developed a list of aging management programs (AMPs) in the GALL Report that are based on conformance with the 10-program element criteria defined in Section A.1.2.3 of the SRP-LR. Some of the AMPs referenced in the GALL Report are based entirely or in part on compliance with the requirements of ASME Section XI, as endorsed for use through reference in 10 CFR 50.55a. For these AMPs, the staff has determined that the referenced ASME Section XI programs or requirements provide an acceptable basis for managing the effects of aging during the period of extended operation, except where noted and augmented in the GALL Report.

For aging management purposes, consideration of the acceptability for license renewal of ASME Section XI editions and addenda from the 1995 edition through the 2004 Addenda are discussed in FRNs 67 FR 60520 (September 26, 2002); 69 FR 58804 (October 1, 2004); and 73 FR 52730 (September 10, 2008) (via update of 10 CFR 50.55a). These FRNs indicate that ASME Section XI editions and addenda from the 1995 edition through the 2004 edition, as modified and limited in the final rule, are acceptable and the conclusions in the GALL Report remain valid. Future FRNs that amend 10 CFR 50.55a will discuss the acceptability of editions and addenda more recent than the 2004 edition for their applicability for aging management for license renewal. Therefore, except where noted and augmented in the GALL Report, the following ASME Section XI editions and addenda are acceptable and should be treated as consistent with the GALL Report: (1) from the 1995 edition to the 2004 edition, as modified and limited in 10 CFR 50.55a, and (2) more recent editions, as evaluated for their adequacy for license renewal and discussed in the accompanying FRN for 10 CFR 50.55a rulemaking endorsing those specific editions. Hence, applicants for renewal should justify any exception to use an ASME Section XI edition or addenda that is (1) earlier than the 1995 edition, (2) not endorsed in 10 CFR 50.55a, or (3) not adequate for license renewal as discussed in the FRN issuing the 10 CFR 50.55a amendment.

In some cases, the staff has determined that specific requirements in ASME Section XI need to be augmented in order to ensure adequate aging management consistent with the license renewal rule. Thus, some of the AMPs in the GALL Report provide for additional augmented actions. For these situations, applicants for renewal should review the recommendations in the GALL Report and discuss proposed enhancements in their License Renewal Application (LRA).

Pursuant to 10 CFR 50.55a(g)(4), a nuclear licensee is required to amend its current licensing basis (CLB) by updating its ASME Section XI edition and addenda of record to the most recently endorsed edition and addenda referenced in 10 CFR 50.55a one year prior to entering the next 10-year internal inservice inspection (ISI) for its unit. Pursuant to 10 CFR 54.21(b), an applicant for license renewal is required to periodically submit updates of its LRA to identify any changes in its CLB that materially affect the contents of the LRA. The rule requires an update of the LRA each year following the submittal of the application and an additional update 3 months prior to the completion of the NRC's review of the LRA. If an applicant's ASME Section XI edition of record is updated under the requirements of 10 CFR 50.55a(g)(4) during the NRC's review of the LRA, the applicant should update those AMPs in the LRA that are impacted by this change in the CLB when the applicant submits the next update of the LRA required by 10 CFR 54.21(b).

The current regulatory process, including 10 CFR 50.55a, continues into the period of extended operation. The NRC Director of the Office of Nuclear Reactor Regulation may approve a licensee-proposed alternative to ASME Section XI if it is submitted as a relief request in accordance with 10 CFR 50.55a(a)(3). The staff's approval of an alternative program/relief request typically does not extend beyond the current 10-year interval for which the alternative was proposed. For cases in which this interval extends beyond the initial 40-year license period into the renewed license period, the approved relief remains in effect until the end of that interval, consistent with the specific approval (60 FR 22466, 22483).

Pursuant to 10 CFR 50.55a(b)(5), licensees may apply ASME Code cases listed in NRC Regulatory Guide (RG) 1.147, through the most recent endorsed revision, without NRC approval, subject to the limitations contained in the rule. The rule permits licensees to continue to apply the Code case, or a most recent version that is incorporated by the RG, until the end of the 10-year interval. For cases in which this interval extends beyond the initial 40-year license period into the renewal period, the Code case, or a more recent endorsed version, remains in effect until the end of that interval, consistent with the intent of the rule and 60 FR 22466, 22483, and 22483.

CHAPTER X

TIME-LIMITED AGING ANALYSES
EVALUATION OF AGING MANAGEMENT PROGRAMS
UNDER 10 CFR 54.21(C)(1)(III)

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TIME-LIMITED AGING ANALYSES: EVALUATION OF AGING MANAGEMENT PROGRAMS UNDER 10 CFR 54.21(c)(1)(iii)

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X.M1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

Program Description

Fatigue usage factor is a computed mechanical parameter suitable for gauging fatigue damage in structural components subjected to fluctuating stresses. Crack initiation is assumed to have started in a structural component when the fatigue usage factor at a point of the structural component reaches the value of 1, the design limit on fatigue. In order not to exceed the design limit on fatigue usage, the aging management program (AMP) monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components.

The AMP addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a set of sample critical components for the plant. Examples of critical components are identified in NUREG/CR-6260. The environmentally adjusted fatigue usage factor can be calculated by multiplying the regular fatigue usage factor evaluated in accordance with the ASME Section III guidelines, in air environment, by an environmental fatigue life correction factor. Formulae for calculating the environmental fatigue life correction factors are contained NUREG/CR-6909 for carbon and low alloy steel, stainless steel, and nickel alloys.

As discussed below, this is an acceptable program for managing metal fatigue for the reactor coolant pressure boundary, considering environmental effects.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope includes those components that the GALL Report identifies in AMR line items that have an aging effect of cumulative fatigue damage. The program monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components. For a set of sample of components, the program includes fatigue usage calculations that consider the effects of the reactor water environment. The program ensures the fatigue usage remaining within the allowable limit, thus minimizing fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

2. ***Preventive Actions:*** The program consists of transient monitoring and tracking mechanisms to measure the severity of transient events and number of occurrences so as to prevent the cumulative usage factor from exceeding the design code limits.

3. ***Parameters Monitored/Inspected:*** The program monitors all plant design transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The number of occurrences of the plant transients that cause significant fatigue usage for each critical reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed monitoring of local pressure and thermal conditions may be performed to allow the actual fatigue usage for the specified critical locations to be calculated.

4. ***Detection of Aging Effects:*** The program provides for updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified. The program monitors a set of sample high fatigue usage locations. This sample set includes the locations identified in NUREG/CR-6260, as minimum, or proposes alternatives based on plant configuration.

5. ***Monitoring and Trending:*** Trending is assessed to ensure that the fatigue usage factor tends to be confined within the allowable limit during the period of extended operation, thus minimizing fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

6. ***Acceptance Criteria:*** The acceptance criterion is maintaining the cumulative fatigue usage below the design code limit through the renewed license term, with consideration of the reactor water environmental fatigue effects described in the program description.

7. ***Corrective Actions:*** The program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation. Acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the period of extended operation. For programs that monitor high fatigue usage locations, corrective actions include a review of additional affected reactor coolant pressure boundary locations. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The program reviews industry experience relevant to fatigue cracking. Applicable operating experience relevant to fatigue cracking is to be considered in selecting the locations for monitoring. As discussed in NRC Regulatory Issue Summary 2008-30, the use of certain simplified analysis methodology to demonstrate compliance with the ASME Code fatigue acceptance criteria could be nonconservative; therefore, a confirmatory analysis is recommended.

References

NRC Regulatory Issue Summary 2008-30, *Fatigue Analysis of Nuclear Power Plant Components*, U.S. Nuclear Regulatory Commission, December 16, 2008.

NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,* U.S. Nuclear Regulatory Commission, March 1995.

NUREG/CR-6909, *Effects of LWR Coolant Environments on the Fatigue Life of Reactor Materials,* U.S. Nuclear Regulatory Commission, February 2007.

X.E1 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS

Program Description

The Nuclear Regulatory Commission (NRC) has established nuclear station environmental qualification (EQ) requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49. 10 CFR 50.49 specifically requires that an EQ program be established to demonstrate that certain electrical components located in harsh plant environments (that is, those areas of the plant that could be subject to the harsh environmental effects of a loss of coolant accident [LOCA], high energy line breaks, or post-LOCA environment) are qualified to perform their safety function in those harsh environments after the effects of inservice aging. 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed as part of environmental qualification.

All operating plants shall meet the requirements of 10 CFR 50.49 for certain electrical components important to safety. 10 CFR 50.49 defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and the environmental conditions to which the components could be subjected. 10 CFR 50.49(e)(5) contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. 10 CFR 50.49(e) also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. 10 CFR 50.49(f) establishes four methods of demonstrating qualification for aging and accident conditions. 10 CFR 50.49(k) and (l) permit different qualification criteria to apply based on plant and component vintage. Supplemental EQ regulatory guidance for compliance with these different qualification criteria is provided in the Division of Operating Reactors (DOR) Guidelines; Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors; NUREG-0588, “Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment”; and Regulatory Guide 1.89, Rev. 1, “Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants.” Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of inservice aging.

EQ programs manage component thermal, radiation, and cyclical aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered time-limited aging analyses (TLAAs) for license renewal.

Under 10 CFR 54.21(c)(1)(iii), plant EQ programs, which implement the requirements of 10 CFR 50.49 (as further defined and clarified by the DOR Guidelines, NUREG-0588, and Regulatory Guide 1.89, Rev. 1), are viewed as aging management programs (AMPs) for license renewal. Reanalysis of an aging evaluation to extend the qualification of components under 10 CFR 50.49(e) is performed on a routine basis as part of an EQ program. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed in the "EQ Component Reanalysis Attributes" section.

This reanalysis program can be applied to EQ components now qualified for the current operating term (i.e., those components now qualified for 40 years or more). As evaluated below, this is an acceptable AMP. Thus, no further evaluation is recommended for license renewal if an applicant elects this option under 10 CFR 54.21(c)(1)(iii) to evaluate the TLAA of EQ of electric equipment. The reanalysis showing the 60-year qualification is established prior to the plant entering the extended period of operation. As defined in 10 CFR 50.49(j), a record of the qualification must be maintained in an auditable form for the entire extended period of operation during which the covered item is installed in the nuclear power plant or is stored for future use; this permits verification that each item of electric equipment important to safety covered by this section (a) is qualified for its application and (b) meets its specified performance requirements when it is subjected to the conditions predicted to be present when it must perform a safety function up to the end of qualified life.

EQ Component Reanalysis Attributes

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of an EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to the station's quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods: The analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods: Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation is conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation, or (b) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis are justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions: EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions: The reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component is refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is performed in a timely manner (that is, sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

Evaluation and Technical Basis

11. ***Scope of Program:*** EQ programs apply to certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49 and Regulatory Guide 1.89, Rev.1.

12. ***Preventive Actions:*** 10 CFR 50.49 does not require actions that prevent aging effects. EQ program actions that could be viewed as preventive actions include (a) establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit) and (b) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain component aging effects within the bounds of the qualification basis.

13. ***Parameters Monitored/Inspected:*** EQ component qualified life is not based on condition or performance monitoring. However, pursuant to Regulatory Guide 1.89, Rev. 1, such monitoring programs are an acceptable basis to modify a qualified life through reanalysis. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

14. ***Detection of Aging Effects:*** 10 CFR 50.49 does not require the detection of aging effects for in-service components. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

15. ***Monitoring and Trending:*** 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging. EQ program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within the bounds of its qualification basis, or as a means to modify the qualification.

16. ***Acceptance Criteria:*** 10 CFR 50.49 acceptance criteria are that an inservice EQ component is maintained within the bounds of its qualification basis, including (a) its established qualified life and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

17. ***Corrective Actions:*** If an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

18. ***Confirmation Process:*** Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

19. ***Administrative Controls:*** EQ programs are implemented through the use of station policy, directives, and procedures. EQ programs continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. EQ program documents identify the applicable environmental conditions for the component locations. EQ program qualification files are maintained at the plant site in an auditable form for the duration of the installed life of the component. EQ program documentation is controlled under the station's quality assurance program. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

20. ***Operating Experience:*** EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of inservice aging.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 54.21, *Contents of Application—Technical Information*, Office of the Federal Register, National Archives and Records Administration, May 1995.

DOR Guidelines, *Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors,* November 1979.

NRC Regulatory Guide 1.89, Rev. 1, *Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants,* U. S. Nuclear Regulatory Commission, June 1984.

NRC Regulatory Issue Summary 2003-09, *Environmental Qualification of Low-Voltage Instrumentation and Control Cables*, May 2, 2003.

NUREG-0588, *Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment,* U. S. Nuclear Regulatory Commission, July 1981.

XI.M1 ASME SECTION XI INSERVICE INSPECTION, SUBSECTIONS IWB, IWC, AND IWD

Program Description

Title 10 of the *Code of Federal Regulations*, 10 CFR 50.55a, imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, for Class 1, 2, and 3 pressure-retaining components and their integral attachments in light-water cooled power plants. Inspection of these components is covered in Subsections IWB, IWC, and IWD, respectively, in the 2004 edition[1] (no addenda). The program generally includes periodic visual, surface, and/or volumetric examination and leakage test of all Class 1, 2, and 3 pressure-retaining components and their integral attachments. Repair/replacement activities for these components are covered in Subsection IWA of the ASME code.

The ASME Section XI inservice inspection program, in accordance with Subsections IWB, IWC, or IWD, has been shown to be generally effective in managing aging effects in Class 1, 2, or 3 components and their integral attachments in light-water cooled power plants. 10 CFR 50.55a imposes additional limitations, modifications, and augmentations of ISI requirements specified in ASME Code, Section XI, and those limitations, modifications, or augmentations described in 10 CFR 50.55a are included as part of this program. In certain cases, the ASME inservice inspection program is to be augmented to manage effects of aging for license renewal and is so identified in the Generic Aging Lessons Learned (GALL) Report.

Evaluation and Technical Basis

21. ***Scope of Program:*** The ASME Section XI program provides the requirements for ISI, repair, and replacement of code Class 1, 2, or 3 pressure-retaining components and their integral attachments in light-water cooled nuclear power plants. The components within the scope of the program are specified in ASME Code, Section XI, Subsections IWB-1100, IWC-1100, and IWD-1100 for Class 1, 2, and 3 components, respectively. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

22. ***Preventive Actions:*** This is a condition monitoring program. It does not implement preventive actions.

23. ***Parameters Monitored/Inspected:*** The ASME Section XI ISI program detects degradation of components by using the examination and inspection requirements specified in ASME Section XI, Tables IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, for Class 1, 2, or 3 components.

    The program uses three types of examination—visual, surface, and volumetric—in accordance with the requirements of Subsection IWA-2000. Visual VT-1 examination detects discontinuities and imperfections, such as cracks, corrosion, wear, or erosion, on the surface of components. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test. Visual VT-3 examination (a) determines the general mechanical and structural condition of components and their supports by verifying parameters such as clearances, settings, and physical displacements; (b) detects discontinuities and imperfections, such as loss of integrity at

[1] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

bolted or welded connections, loose or missing parts, debris, corrosion, wear, or erosion; and (c) observes conditions that could affect operability or functional adequacy of constant-load and spring-type components and supports.

Surface examination uses magnetic particle, liquid penetrant, or eddy current examinations to indicate the presence of surface discontinuities and flaws.

Volumetric examination uses radiographic, ultrasonic, or eddy current examinations to indicate the presence of discontinuities or flaws throughout the volume of material included in the inspection program.

24. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion, leakage of coolant, and indications of degradation due to wear or stress relaxation, such as verification of clearances, settings, physical displacements, loose or missing parts, debris, wear, erosion, or loss of integrity at bolted or welded connections.

Components are examined and tested as specified in Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1, respectively, for Class 1, 2, and 3 components. The tables specify the extent and schedule of the inspection and examination methods for the components of the pressure-retaining boundaries. Alternative approved methods that meet the requirements of IWA-2240 are also specified in these tables. For boiling water reactors (BWRs), the nondestructive examination (NDE) techniques appropriate for inspection of vessel internals, including the uncertainties inherent in delivering and executing an NDE technique in a BWR, are included in the approved Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03.

25. ***Monitoring and Trending:*** For Class 1, 2, or 3 components, the inspection schedule of IWB-2400, IWC-2400, or IWD-2400, respectively, and the extent and frequency of IWB-2500-1, IWC-2500-1, or IWD-2500-1, respectively, provides for timely detection of degradation. The sequence of component examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. If flaw conditions or relevant conditions of degradation are evaluated in accordance with IWB-3100, IWC-3100, or IWD-3000[1], and the component is qualified as acceptable for continued service, the areas containing such flaw indications and relevant conditions are reexamined during the next three inspection periods of IWB-24110 for Class 1 components, IWC-2410 for Class 2 components, and IWD-2410 for Class 3 components. Examinations that reveal indications that exceed the acceptance standards described below are extended to include additional examinations in accordance with IWB-2430, IWC-2430, or IWD-2430 for Class 1, 2, or, 3 components, respectively.

26. ***Acceptance Criteria:*** Any indication or relevant conditions of degradation detected are evaluated in accordance with IWB-3000, IWC-3000, or IWD-3000[1] for Class 1, 2, or 3 components, respectively. Examination results are evaluated in accordance with IWB-3100 or IWC-3100 by comparing the results with the acceptance standards of IWB-3400 and IWB-3500, or IWC-3400 and IWC-3500, respectively, for Class 1 and 3 or Class 2 components.

[1] Article IWD-3000, which is intended to include IWD-3100 through IWD-3600, was in the course of preparation as of the publication of the 2004 edition of ASME Code Section XI. In lieu of providing specific guidance, IWD-3000 stated that the rules of IWB-3000 may be used.

Flaws that exceed the size of allowable flaws, as defined in IWB-3500 or IWC-3500, are evaluated by using the analytical procedures of IWB-3600 or IWC-3600, respectively, for Class 1 and 3 components. Flaws that exceed the size of allowable flaws, as defined in IWB-3500 or IWC-3500, are evaluated by using the analytical procedures of IWB-3600 or IWC-3600, respectively, for Class 1 and 3 or Class 2 components.

27. ***Corrective Actions:*** Repair and replacement activities are performed in conformance with IWA-4000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

28. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

29. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

30. ***Operating Experience:*** Because the ASME Code is a consensus document that has been widely used over a long period, it has been shown to be generally effective in managing aging effects in Class 1, 2, and 3 components and their integral attachments in light-water cooled power plants (see Chapter I of the GALL Report, Vol. 2).

    Some specific examples of operating experience of component degradation are as follows:

    BWR: Cracking due to intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel alloys. IGSCC has also occurred in a number of vessel internal components, such as core shrouds, access hole covers, top guides, and core spray spargers (U.S. Nuclear Regulatory Commission [NRC] Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG-1544). Cracking due to thermal and mechanical loading have occurred in high-pressure coolant injection piping (NRC IN 89-80) and instrument lines (NRC Licensee Event Report [LER] 50-249/99-003-01). Jet pump BWRs are designed with access holes in the shroud support plate at the bottom of the annulus between the core shroud and the reactor vessel wall. These holes are used for access during construction and are subsequently closed by welding a plate over the hole. Both circumferential (NRC IN 88-03) and radial cracking (NRC IN 92-57) have been observed in access hole covers. Failure of the isolation condenser tube bundles due to thermal fatigue and transgranular stress corrosion cracking (TGSCC) caused by leaky valves has also occurred (NRC LER 50-219/98-014-00).

    PWR Primary System: Although the primary pressure boundary piping of PWRs has generally not been found to be affected by stress corrosion cracking (SCC) because of low dissolved oxygen levels and control of primary water chemistry, SCC has occurred in safety injection lines (NRC IN 97-19 and 84-18), charging pump casing cladding (NRC IN 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), control rod drive seal housing (NRC Inspection Report 50-255/99012), and safety-related stainless steel (SS) piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Cracking has occurred in SS baffle former bolts in a number of foreign plants (NRC IN 98-11) and has been observed in plants in the United States. Cracking due to thermal and mechanical loading has occurred in high-pressure injection and safety injection piping (NRC IN 97-46 and NRC Bulletin 88-08). Through-wall circumferential cracking has been found in reactor pressure vessel head control rod drive penetration nozzles (NRC IN 2001-05). Evidence of reactor coolant leakage, together with crack-like indications, has been found in bottom-mounted instrumentation nozzles (NRC IN 2003-11 and IN 2003-11, Supplement 1). Cracking in pressurizer safety and relief line nozzles and in surge line nozzles has been detected (NRC IN 2004-11), and circumferential cracking in stainless steel pressurizer heater sleeves has also been found (NRC IN 2006-27). Also, primary water stress corrosion cracking has been observed in steam generator drain bowl welds inspected as part of a licensee's Alloy 600/82/182 program (NRC IN 2005-02).

PWR Secondary System: Steam generator tubes have experienced outside diameter stress corrosion cracking, intergranular attack, wastage, and pitting (NRC IN 97-88). Carbon steel support plates in steam generators have experienced general corrosion. Steam generator shells have experienced pitting and stress corrosion cracking (NRC INs 82-37, 85-65, and 90-04).

References

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NRC Information Notice 80-38, *Cracking in Charging Pump Casing Cladding*, U.S. Nuclear Regulatory Commission, October 31, 1980.

NRC Information Notice 82-37, *Cracking in the Upper Shell to Transition Cone Girth Weld of a Steam Generator at an Operating PWR*, U.S. Nuclear Regulatory Commission, September 16, 1982.

NRC Information Notice 84-18, *Stress Corrosion Cracking in PWR Systems*, U.S. Nuclear Regulatory Commission, March 7, 1984.

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NRC Information Notice 88-03, *Cracks in Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, February 2, 1988.

NRC Information Notice 89-80, *Potential for Water Hammer, Thermal Stratification, and Steam Binding in High-Pressure Coolant Injection Piping*, U.S. Nuclear Regulatory Commission, December 1, 1989.

NRC Information Notice 90-04, *Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators*, U.S. Nuclear Regulatory Commission, January 26, 1990.

NRC Information Notice 91-05, *Intergranular Stress Corrosion Cracking in Pressurized Water Reactor Safety Injection Accumulator Nozzles*, U.S. Nuclear Regulatory Commission, January 30, 1991.

NRC Information Notice 92-57, *Radial Cracking of Shroud Support Access Hole Cover Welds*, U.S. Nuclear Regulatory Commission, August 11, 1992.

NRC Information Notice 94-63, *Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks*, U.S. Nuclear Regulatory Commission, August 30, 1994.

NRC Information Notice 95-17, *Reactor Vessel Top Guide and Core Plate Cracking*, U.S. Nuclear Regulatory Commission, March 10, 1995.

NRC Information Notice 97-19, *Safety Injection System Weld Flaw at Sequoyah Nuclear Power Plant, Unit 2*, U.S. Nuclear Regulatory Commission, April 18, 1997.

NRC Information Notice 97-46, *Unisolable Crack in High-Pressure Injection Piping*, U.S. Nuclear Regulatory Commission, July 9, 1997.

NRC Information Notice 97-88, *Experiences During Recent Steam Generator Inspection*s, U.S. Nuclear Regulatory Commission, December 16, 1997.

NRC Information Notice 98-11, *Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants*, U.S. Nuclear Regulatory Commission, March 25, 1998.

NRC Information Notice 2001-05, *Through-Wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3*, U.S. Nuclear Regulatory Commission, April 30, 2001.

NRC Information Notice 2003-11, *Leakage Found on Bottom-Mounted Instrumentation Nozzles*, U.S. Nuclear Regulatory Commission, August 13, 2003.

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NRC Information Notice 2004-11, *Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzles*, U.S. Nuclear Regulatory Commission, May 4, 2004.

NRC Information Notice 2005-02, *Pressure Boundary Leakage Identified on Steam Generator Drain Bowl Welds*, U.S. Nuclear Regulatory Commission, February 4, 2005.

NRC Information Notice 2006-27, *Circumferential Cracking in the Stainless Steel Pressurizer Heater Sleeves of Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, December 11, 2006.

NRC Inspection Report 50-255/99012, *Palisades Inspection Report*, Item E8.2, Licensee Event Report 50-255/99-004, *Control Rod Drive Seal Housing Leaks and Crack Indications*, U.S. Nuclear Regulatory Commission, January 12, 2000.

NRC Licensee Event Report LER 50-219/98-014-00, *Failure of the Isolation Condenser Tube Bundles due to Thermal Stresses/Transgranular Stress Corrosion Cracking Caused by Leaky Valve*, U.S. Nuclear Regulatory Commission, October 29, 1998.

NRC Licensee Event Report LER 50-249/99-003-01, *Supplement to Reactor Recirculation B Loop, High Pressure Flow Element Venturi Instrument Line Steam Leakage Results in Unit 3 Shutdown Due to Fatigue Failure of Socket Welded Pipe Joint*, U.S. Nuclear Regulatory Commission, August 30, 1999.

NUREG-1544, *Status Report: Intergranular Stress Corrosion Cracking of BWR Core Shrouds and Other Internal Components*, U.S. Nuclear Regulatory Commission, March 1, 1996.

XI.M2 WATER CHEMISTRY

Program Description

The main objective of this program is to mitigate loss of material due to corrosion and cracking due to stress corrosion cracking (SCC) in components exposed to a treated water environment. The program includes periodic monitoring of the treated water and control of known detrimental contaminants such as chlorides, fluorides (pressurized water reactors [PWRs] only), dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking.

The water chemistry program for boiling water reactors (BWRs) relies on monitoring and control of reactor water chemistry based on industry guidelines, such as the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-130 (Electric Power Research Institute [EPRI] 1008192) or later revisions. The BWRVIP-130 has three sets of guidelines: one for primary water, one for condensate and feedwater, and one for control rod drive (CRD) mechanism cooling water. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on industry guidelines for primary water and secondary water chemistry such as EPRI 105714, Revision 4, and 1008224, Revision 6, or later revisions.

The water chemistry programs are generally effective in removing impurities from intermediate and high flow areas. The Generic Aging Lessons Learned (GALL) report identifies those circumstances in which the water chemistry program is to be augmented to manage the effects of aging for license renewal. For example, the water chemistry program may not be effective in low flow or stagnant flow areas. Accordingly, in certain cases as identified in the GALL Report, verification of the effectiveness of the chemistry control program is undertaken to ensure that significant degradation is not occurring and the component’s intended function is maintained during the extended period of operation. As discussed in the GALL Report for these specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

Evaluation and Technical Basis

31. ***Scope of Program:*** The program includes components in the reactor coolant system, the engineered safety features, the auxiliary systems, and the steam and power conversion system. This program addresses the metallic components subject to aging management review that are exposed to a treated water environment controlled by the water chemistry program.

32. ***Preventive Actions:*** The program includes specifications for chemical species, impurities and additives, sampling and analysis frequencies, and corrective actions for control of reactor water chemistry. System water chemistry is controlled to minimize contaminant concentration and mitigate loss of material due to general, crevice, and pitting corrosion and cracking caused by SCC. For BWRs, maintaining high water purity reduces susceptibility to SCC, and chemical additive programs such as hydrogen water chemistry, zinc injection, or noble metal chemical application may also be used. For PWRs, additives are used for reactivity control and to control pH and inhibit corrosion.

33. ***Parameters Monitored/Inspected:*** The concentration of corrosive impurities listed in the EPRI water chemistry guidelines, which include chlorides, fluorides (PWRs only), sulfates, dissolved oxygen, and hydrogen peroxide, are monitored to mitigate loss of material and

cracking. Water quality (pH and conductivity) is also maintained in accordance with the guidance. Chemical species and water quality are monitored by in-process methods or through sampling. The chemical integrity of the samples is maintained and verified to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples.

BWR Water Chemistry: The EPRI guidelines for BWR reactor water recommend that the concentration of chlorides, sulfates, and dissolved oxygen are monitored and kept below the recommended levels to mitigate corrosion. The two impurities, chlorides and sulfates, determine the coolant conductivity; dissolved oxygen, hydrogen peroxide, and hydrogen determine electrochemical potential (ECP). The EPRI guidelines recommend that the coolant conductivity and ECP are also monitored and kept below the recommended levels to mitigate SCC and corrosion in BWR plants. The EPRI guidelines for BWR feedwater, condensate, and CRD water recommend that conductivity, dissolved oxygen level, and concentrations of iron and copper (feedwater only) are monitored and kept below the recommended levels to mitigate SCC. The EPRI guidelines also include recommendations for controlling water chemistry in auxiliary systems: torus/pressure suppression chamber, condensate storage tank, and spent fuel pool.

PWR Primary Water Chemistry: The EPRI guidelines for PWR primary water chemistry recommend that the concentration of chlorides, fluorides, sulfates, lithium, and dissolved oxygen and hydrogen are monitored and kept below the recommended levels to mitigate SCC of austenitic stainless steel (SS), Alloy 600, and Alloy 690 components. The EPRI PWR primary water chemistry guidelines also provide recommendations for chemistry control in PWR auxiliary systems, such as the boric acid storage tank, refueling water storage tank, spent fuel pool, letdown purification systems, and volume control tank.

PWR Secondary Water Chemistry: The EPRI guidelines for PWR secondary water chemistry recommend monitoring and control of chemistry parameters (e.g., pH level, cation conductivity, sodium, chloride, sulfate, lead, dissolved oxygen, iron, copper, and hydrazine) to mitigate steam generator tube degradation caused by denting, intergranular attack (IGA), outer diameter stress corrosion cracking (ODSCC), or crevice and pitting corrosion. The monitoring and control of these parameters, especially the pH level, also mitigates general (for steel components), crevice, and pitting corrosion of the steam generator shell and the balance of plant materials of construction (e.g., steel, SS, and copper).

34. ***Detection of Aging Effects:*** This is a mitigation program and does not provide for detection of any aging effects for the components within its scope. The monitoring methods and frequency of water chemistry sampling and testing is performed in accordance with the EPRI water chemistry guidelines and based on plant operating conditions. The main objective of this program is to mitigate loss of material due to corrosion and by cracking due to SCC in components exposed to a treated water environment.

    In certain cases, as identified by the AMR line items in the GALL Report, inspection of select components is to be undertaken to verify the effectiveness of the chemistry control program and to ensure that significant degradation is not occurring and the component intended function is maintained during the extended period of operation.

35. ***Monitoring and Trending:*** Chemistry parameter data are recorded and evaluated in accordance with the EPRI water chemistry guidelines. Whenever corrective actions are

taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions.

36. ***Acceptance Criteria:*** Maximum levels for various chemical parameters are maintained within the system-specific limits as indicated by the limits specified in the corresponding EPRI water chemistry guidelines.

37. ***Corrective Actions:*** Any evidence of aging effects or unacceptable water chemistry results are evaluated, the root cause identified, and the condition corrected. When measured water chemistry parameters are outside the specified range, corrective actions are taken to bring the parameter back within the acceptable range (or to change the operational mode of the plant) within the time period specified in the EPRI water chemistry guidelines. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

38. ***Confirmation Process:*** Following corrective actions, additional samples are taken and analyzed to verify that the corrective actions were effective in returning the concentrations of contaminants, such as chlorides, fluorides, sulfates, dissolved oxygen, and hydrogen peroxide, to within the acceptable ranges. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

39. ***Administrative Controls:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

40. ***Operating Experience:*** The EPRI guideline documents have been developed based on plant experience and have been shown to be effective over time with their widespread use. The specific examples of operating experience are as follows:

    BWR: Intergranular stress corrosion cracking (IGSCC) has occurred in small- and large-diameter BWR piping made of austenitic stainless steels and nickel-base alloys. Significant cracking has occurred in recirculation, core spray, residual heat removal systems, and reactor water cleanup system piping welds. IGSCC has also occurred in a number of vessel internal components, including core shroud, access hole cover, top guide, and core spray spargers (Nuclear Regulatory Commission [NRC] Bulletin 80-13, NRC Information Notice [IN] 95-17, NRC Generic Letter [GL] 94-03, and NUREG-1544). No occurrence of SCC in piping and other components in standby liquid control systems exposed to sodium pentaborate solution has ever been reported (NUREG/CR-6001).

    PWR Primary System: The potential for SCC-type mechanisms might normally occur because of inadvertent introduction of contaminants into the primary coolant system, including contaminants introduced from the free surface of the spent fuel pool (which can be a natural collector of airborne contaminants) or the introduction of oxygen during plant cooldowns (NRC IN 84–18). Ingress of demineralizer resins into the primary system has caused IGSCC of Alloy 600 vessel head penetrations (NRC IN 96-11, NRC GL 97-01). Inadvertent introduction of sodium thiosulfate into the primary system has caused IGSCC of steam generator tubes. SCC has occurred in safety injection lines (NRC INs 97-19 and 84-18), charging pump casing cladding (NRC INs 80-38 and 94-63), instrument nozzles in safety injection tanks (NRC IN 91-05), and safety-related SS piping systems that contain oxygenated, stagnant, or essentially stagnant borated coolant (NRC IN 97-19). Steam generator tubes and plugs and Alloy 600 penetrations have experienced primary water stress corrosion cracking (NRC INs 89-33, 94-87, 97-88, 90-10, and 96-11; NRC Bulletin 89-01 and its two supplements). IGSCC-induced circumferential cracking has occurred in PWR pressurizer heater sleeves (NRC IN 2006-27).

PWR Secondary System: Steam generator tubes have experienced ODSCC, IGA, wastage, and pitting (NRC IN 97-88, NRC GL 95-05). Carbon steel support plates in steam generators have experienced general corrosion. The steam generator shell has experienced pitting and stress corrosion cracking (NRC INs 82-37, 85-65, and 90-04). Extensive buildup of deposits at steam generator tube support holes can result in flow-induced vibrations and tube cracking (NRC IN 2007-37).

Such operating experience has provided feedback to revisions of the EPRI water chemistry guideline documents.

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BWRVIP-190 (EPRI 1016579), *BWR Water Chemistry Guidelines-2008 Revision*, Electric Power Research Institute, Palo Alto, CA, October 2008.

EPRI 1008224, *PWR Secondary Water Chemistry Guidelines–Revision 6*, Electric Power Research Institute, Palo Alto, CA, December 2004.

EPRI 1016555, *PWR Secondary Water Chemistry Guidelines–Revision 7*, Electric Power Research Institute, Palo Alto, CA, February 2009.

EPRI 105714, *PWR Primary Water Chemistry Guideline,* Revision 4, Volumes 1 and 2, Electric Power Research Institute, Palo Alto, CA, March 1999.

EPRI 1002884, *PWR Primary Water Chemistry Guidelines,* Revision 5, Volumes 1 and 2, Electric Power Research Institute, Palo Alto, CA, October 2003.

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NRC Information Notice 89-33, *Potential Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, March 23, 1989.

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NRC Information Notice 91-05, *Intergranular Stress Corrosion Cracking In Pressurized Water Reactor Safety Injection Accumulator Nozzles*, U.S. Nuclear Regulatory Commission, January 30, 1991.

NRC Information Notice 94-63, *Boric Acid Corrosion of Charging Pump Casing Caused by Cladding Cracks*, U.S. Nuclear Regulatory Commission, August 30, 1994.

NRC Information Notice 94-87, *Unanticipated Crack in a Particular Heat of Alloy 600 Used for Westinghouse Mechanical Plugs for Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, December 22, 1994.

NRC Information Notice 95-17, *Reactor Vessel Top Guide and Core Plate Cracking*, U.S. Nuclear Regulatory Commission, March 10, 1995.

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XI.M3 REACTOR HEAD CLOSURE STUD BOLTING

Program Description

This program includes (a) inservice inspection (ISI) in conformance with the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB (2004 edition[3], no addenda), Table IWB 2500-1; and (b) preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting degradation as delineated in NUREG-1339 and Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.65.

Evaluation and Technical Basis

41. ***Scope of Program:*** The program manages the aging effects of cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) and loss of material due to wear or corrosion for reactor vessel closure stud bolting (studs, washers, bushings, nuts, and threads in flange) for both boiling water reactors (BWRs) and pressurized water reactors (PWRs).

42. ***Preventive Actions:*** Preventive measures include (a) avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement and (b) using manganese phosphate or other acceptable surface treatments and stable lubricants (RG 1.65). Of particular note, use of molybdenum disulfide (MoS_2) as a lubricant has been shown to be a potential contributor to SCC and should not be used. Preventive measures also include using bolting material for closure studs that has an actual measured yield strength limited to less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch) (NUREG-1339). Implementation of these mitigation measures can reduce potential for SCC or IGSCC, thus making this program effective.

43. ***Parameters Monitored/Inspected:*** The ASME Section XI ISI program detects and sizes cracks, detects loss of material, and detects coolant leakage by following the examination and inspection requirements specified in Table IWB-2500-1.

    The program uses visual, surface, and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. Surface examination uses magnetic particle or liquid penetrant examinations to indicate the presence of surface discontinuities and flaws. Volumetric examination uses radiographic or ultrasonic examinations to indicate the presence of discontinuities or flaws throughout the volume of material. Visual VT-2 examination detects evidence of leakage from pressure-retaining components, as required during the system pressure test.

44. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by the program are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking, loss of material due to corrosion or wear, and leakage of coolant.

    Components are examined and tested in accordance with ASME Code, Section XI, Table IWB-2500-1, examination category B-G-1, for pressure-retaining bolting greater than

[3] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

2 inches in diameter. Examination category B-P for all pressure-retaining components specifies visual VT-2 examination of all pressure-retaining boundary components during the system leakage test and the system hydrostatic test. Table IWB-2500-1 specifies the extent and schedule of the inspection and examination methods.

45. ***Monitoring and Trending:*** The Inspection schedule of IWB-2400 and the extent and frequency of IWB-2500-1 provide timely detection of cracks, loss of material, and leakage.

46. ***Acceptance Criteria:*** Any indication or relevant condition of degradation in closure stud bolting is evaluated in accordance with IWB-3100 by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500.

47. ***Corrective Actions:*** Repair and replacement are performed in conformance with the requirements of IWA-4000 and the material and inspection guidance of RG 1.65. Maximum yield strength of replacement material should be limited as recommended in NUREG-1339. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

48. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

49. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

50. ***Operating Experience:*** The SCC has occurred in BWR pressure vessel head studs (Stoller, 1991). The aging management program has provisions regarding inspection techniques and evaluation, material specifications, corrosion prevention, and other aspects of reactor pressure vessel head stud cracking. Implementation of the program provides reasonable assurance that the effects of cracking due to SCC or IGSCC and loss of material due to wear are adequately managed so that the intended functions of the reactor head closure studs and bolts are maintained consistent with the current licensing basis for the period of extended operation. Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC Inspection and Enforcement Bulletin 82-02, NRC Generic Letter 91-17).

References

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XI.M4 BWR VESSEL ID ATTACHMENT WELDS

Program Description

The program includes (a) inspection and flaw evaluation in accordance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP)-48A to ensure the long-term integrity and safe operation of boiling water reactor (BWR) vessel inside diameter (ID) attachment welds.

The guidelines of BWRVIP-48A include inspection recommendations and evaluation methodologies for the attachment welds between the vessel wall and vessel ID brackets that attach safety-related components to the vessel (e.g., jet pump riser braces and core-spray piping brackets). In some cases, the attachment is a simple weld; in others, it includes a weld build-up pad on the vessel. The BWRVIP-48A guidelines include information on the geometry of the vessel ID attachments; evaluate susceptible locations and safety consequence of failure; provide recommendations regarding the method, extent, and frequency of inspection; and discuss acceptable methods for evaluating the structural integrity significance of flaws detected during these examinations.

Evaluation and Technical Basis

51. ***Scope of Program:*** The program is focused on managing the effects of cracking due to stress corrosion cracking (SCC), including intergranular stress corrosion cracking (IGSCC). The program is an augmented inservice inspection program that uses the inspection and flaw evaluation criteria in BWRVIP-48A to detect cracking and monitor the effects of cracking on the intended function of the components. The program provides for repair and/or replacement, as needed, to maintain the ability to perform the intended function. The program is applicable to structural welds for BWR reactor vessel internal integral attachments..

52. ***Preventive Actions:*** The BWRVIP-48A provides guidance on detection but does not provide guidance on methods to mitigate cracking. Maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-130 (EPRI TR-1008192) or later revisions. The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Section XI.M2, “Water Chemistry.”

53. ***Parameters Monitored/Inspected:*** The program monitors for cracks induced by SCC and IGSCC on the intended function of BWR vessel ID attachment welds. The program looks for surface discontinuities that may indicate the presence of a crack in the component by detection in accordance with the guidelines of approved BWRVIP-48A and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB 2500-1 (2004 edition[4]).

54. ***Detection of Aging Effects:*** The extent and schedule of the inspection and test techniques prescribed by BWRVIP-48A guidelines are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function. Inspection can reveal cracking. Vessel ID attachment welds are inspected in accordance with the requirements of ASME Section XI, Subsection IWB, examination category B-N-2.

[4] Refer to the GALL Report, Volume 2, Chapter 1, for applicability of other editions of the ASME Code, Section XI.

The Section XI inspection specifies visual VT-1 examination to detect discontinuities and imperfections on the surfaces of components and visual VT-3 examination to determine the general mechanical and structural condition of the component supports. The inspection and evaluation guidelines of BWRVIP-48A recommend more stringent inspections for certain attachments. The guidelines recommend enhanced visual VT-1 examination of all safety-related attachments and those non-safety-related attachments identified as being susceptible to IGSCC. Visual VT-1 examination is capable of achieving 1/32-inch resolution; the enhanced visual VT-1 examination method is capable of achieving a 1-millimeter wire resolution. The nondestructive examination (NDE) techniques appropriate for inspection of BWR vessel internals, including the uncertainties inherent in delivering and executing NDE techniques in a BWR, are included in BWRVIP-03.

55. ***Monitoring and Trending:*** Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-48A guidelines provide timely detection of cracks. If flaws are detected, the scope of examination is expanded. Any indication detected is evaluated in accordance with ASME Section XI or the staff-approved BWRVIP-48A guidelines. Applicable and approved BWRVIP-14A, BWRVIP-59, and BWRVIP-60 documents provide guidelines for evaluation of crack growth in stainless steels, nickel alloys, and low-alloy steels, respectively.

56. ***Acceptance Criteria:*** Acceptance criteria are given in BWRVIP-48A and ASME Section XI.

57. ***Corrective Actions:*** Repair and replacement procedures are equivalent to those requirements in ASME Section XI. Corrective action is performed in accordance with IWA-4000. As discussed in the appendix to this report, the staff finds that licensee implementation of the corrective action guidelines in BWRVIP-48A provides an acceptable level of quality in accordance with 10 CFR Part 50, Appendix B, corrective actions.

58. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-48A provides an acceptable level of quality in accordance with the 10 CFR Part 50, Appendix B, confirmation process and administrative controls.

59. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

60. ***Operating Experience:*** Cracking due to SCC, including IGSCC, has occurred in BWR components. The program guidelines are based on an evaluation of available information, including BWR inspection data and information on the elements that cause IGSCC, to determine which attachment welds may be susceptible to cracking. Implementation of the program provides reasonable assurance that cracking will be adequately managed and the intended functions of the vessel ID attachments will be maintained consistent with the current licensing basis for the period of extended operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition, American Society of Mechanical Engineers, New York, NY.

BWRVIP-03 (EPRI TR-105696 R1, March 30, 1999), *BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-03, July 15, 1999.

BWRVIP-14-A (EPRI TR-1016569, September 2008), *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals,*

BWRVIP-48A (EPRI TR-1009948, June 2004), *BWR Vessel and Internals Project, Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines.*

BWRVIP-59 (EPRI TR-108710), *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,* March 24, 2000.

BWRVIP-60 (EPRI TR-108709, April 14, 2000), *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-62 (EPRI TR-108705), *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,* March 7, 2000.

BWRVIP-130 (EPRI TR-1008192, 2004), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines 2004 Revision*.

BWRVIP-190 (EPRI TR-1016579), *BWR Vessel and Internals Project: BWR Water Chemistry Guidelines—2008 Revision*, October 2008.

XI.M5 BWR FEEDWATER NOZZLE

Program Description

This program includes enhanced inservice inspection (ISI) in accordance with (a) the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Subsection IWB, Table IWB 2500-1 (2004 edition[5]); (b) the recommendation of General Electric (GE) NE-523-A71-0594; and (c) NUREG-0619 recommendations for system modifications to mitigate cracking. The program specifies periodic ultrasonic inspection of critical regions of the boiling water reactor (BWR) feedwater nozzle.

Systems modifications to mitigate cracking may have been made, such as removal of stainless steel cladding and installation of improved spargers. Mitigation is also accomplished by changes to plant-operating procedures, such as improved feedwater control and rerouting of the reactor water cleanup system, to decrease the magnitude and frequency of temperature fluctuations.

Evaluation and Technical Basis

61. ***Scope of Program:*** The program includes enhanced ISI to monitor the effects of cracking on the intended function of BWR feedwater nozzles.

62. ***Preventive Actions:*** This program is a condition monitoring program and has no preventive actions.

63. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors for cracks induced by cyclic loading on the intended function of the component by detection and sizing of cracks by ISI in accordance with ASME Section XI, Subsection IWB; the recommendation of GE NE-523-A71-0594; and NUREG-0619 recommendations.

64. ***Detection of Aging Effects:*** The extent and schedule of the inspection prescribed by the program are designed to ensure that aging effects are discovered and repaired before the loss of intended function of the component. Inspection can reveal cracking.

    GE NE-523-A71-0594 specifies ultrasonic testing (UT) of specific regions of the blend radius and bore. The UT examination techniques and personnel qualifications are in accordance with the guidelines of GE NE-523-A71-0594. Based on the inspection method and techniques and plant-specific fracture mechanics assessments, the inspection schedule is in accordance with Table 6-1 of GE NE-523-A71-0594. Leakage monitoring may be used to modify the inspection interval.

65. ***Monitoring and Trending:*** Inspections scheduled in accordance with GE NE-523-A71-0594 provide timely detection of cracks.

66. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

67. ***Corrective Actions:*** Repair and replacement are in conformance with ASME Section XI, Subsection IWA-4000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

[5] Refer to the GALL Report, Volume 2, Chapter 1, for applicability of other editions of the ASME Code, Section XI.

68. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

69. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

70. ***Operating Experience:*** Cracking has occurred in several BWR plants (NUREG-0619, U.S. Nuclear Regulatory Commission [NRC] Generic Letter 81-11). This AMP has been implemented for nearly 25 years and has been found to be effective in managing the effects of cracking on the intended function of feedwater nozzles.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition, American Society of Mechanical Engineers, New York, NY.

GE-NE-523-A71-0594, Rev. 1, *Alternate BWR Feedwater Nozzle Inspection Requirements*, BWR Owner's Group, August 1999.

NRC Generic Letter 81-11, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking (NUREG-0619),* U.S. Nuclear Regulatory Commission, February 29, 1981.

NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*, U.S. Nuclear Regulatory Commission, November 1980.

XI.M6 BWR CONTROL ROD DRIVE RETURN LINE NOZZLE

Program Description

This program is a condition monitoring program for boiling water reactor (BWR) control rod drive return line (CRDRL) nozzles that is based on conformance with the staff's recommended position in NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking." The augmented inspections performed in accordance with the recommendations in NUREG-0619 supplement those inservice inspections that are required for these nozzles in accordance with the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB-2500-1, as mandated through reference in 10 CFR 50.55a. Thus, this program includes (a) mandatory inservice inspection (ISI) in conformance with the ASME Section XI, Subsection IWB, Table IWB 2500-1 (2004 edition[6]), and (b) augmented ISI examinations in accordance with applicant's commitments to U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 80-095 to implement the recommendations in NUREG-0619.

Evaluation and Technical Basis

71. ***Scope of Program:*** The program manages the effects of cracking on the intended pressure boundary function of CRDRL nozzles. The scope of this program is applicable to BWRs whose reactor vessel (RV) design includes a welded CRDRL nozzle design. The scope of the program includes CRDRL nozzles and their nozzle-to-RV welds, which are Code Class 1 components. The scope of the program also includes a CRDRL nozzle cap (including any CRDRL nozzle-to-cap welds) if, to mitigate cracking, an applicant has either: (a) cut the piping to the CRDRL nozzle, capped the CRDRL nozzle, and rerouted the CRDRL flow to the RV through an alternate CRDRL flow path or (b) cut and capped the CRDRL nozzle without rerouting of the CRDRL flow path.

72. ***Preventive Actions:*** Activities for preventing or mitigating cracking in CRDRL nozzles are consistent with a BWR facility's past preventive or mitigation actions/activities in its current licensing basis as committed to in an applicant's response to NRC GL 80-095 and made to address the recommendations in NUREG-0619.

73. ***Parameters Monitored/Inspected:*** The aging management program (AMP) manages the effects of cracking on the intended function of the RV, the CRDLR nozzle, and for capped nozzles, the nozzle caps and cap-to-nozzle welds. For liquid dye penetrant test (PT) examinations that are implemented in accordance with this AMP, the AMP monitors for linear liquid dye penetrant indications that may be indicative of surface breaking cracks. For the volumetric ultrasonic test (UT) examinations that are performed in accordance with this AMP, the AMP monitors and evaluates UT indications (signals) that may indicate the presence of a planar flaw (crack).

74. ***Detection of Aging Effects:*** The extent and schedule of inspection, as delineated in NUREG-0619, assures detection of cracks before the loss of intended function of the CRDRL nozzles. Inspection recommendations include PT of CRDRL nozzle blend radius and bore regions and the reactor vessel wall area beneath the nozzle, return-flow-capacity demonstration, control rod drive-system-performance testing, and ultrasonic inspection of welded connections in the rerouted line. The inspection is to include base metal to a

[6] Refer to the GALL Report, Volume 2, Chapter 1, for applicability of other ASME Code editions.

distance of one-pipe-wall thickness or 0.5 inches, whichever is greater, on both sides of the weld.

75. ***Monitoring and Trending:*** The inspection schedule of NUREG-0619 provides timely detection of cracks. Indications of cracking are evaluated and trended in accordance with the ASME Section XI, IWB-3100, against applicable acceptance standard criteria that are specified in the ASME Section XI, IWB-3400 or IWB-3500.

76. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

77. ***Corrective Actions*** Corrective action is performed in conformance with IWA-4000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

78. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

79. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

80. ***Operating Experience:*** Cracking of CRDRL nozzle-to-vessel and nozzle-to-cap welds has occurred in several BWR plants (NUREG-0619 and Information Notice 2004-08). The present AMP has been implemented for nearly 25 years and has been found to be effective in managing the effects of cracking on the intended function of CRDRL nozzles.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards, Office of the Federal Register, National Archives and Records Administration*. The latest update of this regulation was authorized in Federal Register Notice Volume 73, Number 176, Industry Codes and Standards; Amended Requirements, Pages 52730 – 52750, September 10, 2008.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition, American Society of Mechanical Engineers, New York, NY.

Letter from D. G. Eisenhut, U.S. Nuclear Regulatory Commission, to R. Gridley, General Electric Company, *forwarding NRC Generic Technical Activity A-10*, January 28, 1980.

NRC Generic Letter 80-095, (Untitled), November 13, 1980.[7]

NRC Generic Letter 81-11, (Untitled), February 29, 1981.[8]

NRC Information Notice 2004-08, *Reactor Coolant Pressure Boundary Leakage Attributable To Propagation of Cracking In Reactor Vessel Nozzle Welds*, U.S. Nuclear Regulatory Commission, April 22, 2004.

NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*, U.S. Nuclear Regulatory Commission, November 1980.

[7] This GL forwarded NUREG-0619 to members of the U.S nuclear power industry and requested that licensees owning BWR model reactors provide confirmation of their intent to implement the recommendations of NUREG-0619, as applied to the design of their BWRs.
[8] This GL was issued primarily to provide additional clarification on the contents of the confirmatory response that was requested in NRC GL 80-095.

XI.M7 BWR STRESS CORROSION CRACKING

Program Description

The program to manage intergranular stress corrosion cracking (IGSCC) in boiling water reactor (BWR) coolant pressure boundary piping made of stainless steel (SS) and nickel based alloy components is delineated in NUREG-0313, Rev. 2, and Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 and its Supplement 1. The material includes base metal and welds. The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause IGSCC. These elements consist of a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic stainless steels containing greater than 0.03 weight percent carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates a chromium depleted region that, in certain environments, is susceptible to stress corrosion cracking (SCC). Residual tensile stresses are introduced from fabrication processes, such as welding, surface grinding, or forming. High levels of dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes. The program includes (a) preventive measures to mitigate IGSCC and (b) inspection and flaw evaluation to monitor IGSCC and its effects. The staff-approved boiling water reactor vessel and internals project (BWRVIP-75A) report allows for modifications to the inspection scope in the GL 88-01 program.

Evaluation and Technical Basis

81. ***Scope of Program:*** The program focuses on (a) managing and implementing countermeasures to mitigate IGSCC and (b) performing inservice inspection to monitor IGSCC and its effects on the intended function of BWR piping components. The program is applicable to all BWR piping and piping welds made of austenitic SS and nickel alloy that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93 degrees Celsius (200 degrees Fahrenheit) during power operation, regardless of code classification. The program also applies to pump casings, valve bodies, and reactor vessel attachments and appurtenances, such as head spray and vent components. NUREG-0313 and NRC GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigation of IGSCC in BWRs. Attachment A of NRC GL 88-01 delineates the staff-approved positions regarding materials, processes, water chemistry, weld overlay reinforcement, partial replacement, stress improvement of cracked welds, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

82. ***Preventive Actions:*** The program delineated in NUREG-0313 and NRC GL 88-01 does not provide specific guidelines for controlling reactor water chemistry to mitigate IGSCC. Maintaining high water purity reduces susceptibility to SCC or IGSCC. The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are addressed through implementation of Section XI.M2, “Water Chemistry.”

83. ***Parameters Monitored/Inspected:*** The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 or the referenced BWRVIP-75A guideline as approved by the NRC staff.

84. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 or BWRVIP-75A are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. The inspection guidance in approved BWRVIP-75A replaces the extent and schedule of inspection in NRC GL 88-01. The program uses volumetric examinations to detect IGSCC.

    Inspection can reveal cracking and leakage of coolant. The extent and frequency of inspection recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce residual stresses, and how the weld was repaired if it had been cracked).

85. ***Monitoring and Trending:*** The extent and schedule for inspection, in accordance with the recommendations of NRC GL 88-01 or approved BWRVIP-75A guidelines, provide timely detection of cracks and leakage of coolant. Indications of cracking are evaluated and trended in accordance with the 2004[9] edition of the American Society of Mechanical Engineers (ASME) Code, Section XI, IWB-3100, against applicable acceptance standard criteria that are specified in the ASME Code, Section XI, IWB-3400 or IWB-3500. Applicable and approved BWRVIP-14A, BWRVIP-59A, BWRVIP-60, and BWRVIP-62 documents provide guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 guidelines for BWR vessel and internals induction heating stress improvement effectiveness on crack growth in operating plants.

86. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

87. ***Corrective Actions***: The guidance for weld overlay repair and stress improvement or replacement is provided in NRC GL 88-01. Corrective action is performed in accordance with IWA -4000-. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

88. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

89. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

90. ***Operating Experience:*** Intergranular SCC has occurred in small- and large-diameter BWR piping made of austenitic SS and nickel-base alloys. Cracking has occurred in recirculation, core spray, residual heat removal, control rod drive return line penetrations, and reactor water cleanup system piping welds (NRC GL 88-01, NRC Information Notices [INs] 82-39, 84-41, and 04-08). The comprehensive program outlined in NRC GL 88-01, NUREG-0313, and in the staff-approved BWRVIP-75A report addresses mitigating measures for SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive

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[9] Refer to the GALL Report, Volume 2, Chapter 1, for applicability of other editions of ASME Code, Section XI.

environment). The GL 88-01 program has been effective in managing IGSCC in BWR reactor coolant pressure-retaining components, and the revision to the GL 88-01 program, according to the staff-approved BWRVIP-75A report, will adequately manage IGSCC degradation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Code Case N-504-1, *Alternative Rules for Repair of Class 1, 2, and 3 Austenitic Stainless Steel Piping*, Section XI, Division 1, 1995 edition, ASME Boiler and Pressure Vessel Code – Code Cases – Nuclear Components, American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition, American Society of Mechanical Engineers, New York, NY.

BWRVIP-14A, (EPRI TR- New number), *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals,* September 2008.

BWRVIP-59A, (EPRI TR-new number), *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,* May 2007.

BWRVIP-60, (EPRI TR-108709, April 14, 2000), *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-61, (EPRI TR-112076), *BWR Vessel and Internals Induction Heating Stress Improvement Effectiveness on Crack Growth in Operating Reactors,* January 29, 1999.

BWRVIP-62, (EPRI TR-108705), *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,* March 7, 2000.

BWRVIP-75A, (EPRI TR-new number), *Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313),* October 2005.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping*, U.S. Nuclear Regulatory Commission, January 25, 1988; Supplement 1, February 4, 1992.

NRC Information Notice 04-08, *Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds,* U.S. Nuclear Regulatory Commission, April 22, 2004.

NRC Information Notice 82-39, *Service Degradation of Thick Wall Stainless Steel Recirculation System Piping at a BWR Plant*, U.S. Nuclear Regulatory Commission, September 21, 1982.

NRC Information Notice 84-41, *IGSCC in BWR Plants*, U.S. Nuclear Regulatory Commission, June 1, 1984.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping*, W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

XI.M8 BWR PENETRATIONS

Program Description

The program for boiling water reactor (BWR) vessel instrumentation nozzles and standby liquid control (SLC) nozzles/Core ΔP nozzles includes inspection and flaw evaluation in conformance with the guidelines of staff-approved boiling water reactor vessel and internals project (BWRVIP) Topical Reports BWRVIP-49A and BWRVIP-27A. The inspection and evaluation guidelines of BWRVIP-49A and BWRVIP-27A contain generic guidelines intended to present appropriate inspection recommendations to assure safety function integrity. The guidelines of BWRVIP-49A provide information on the type of instrument penetration, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. The guidelines of BWRVIP-27 are applicable to plants in which the SLC system injects sodium pentaborate into the bottom head region of the vessel (in most plants, as a pipe within a pipe of the core plate ΔP monitoring system). The BWRVIP-27 guidelines address the region where the ΔP and SLC nozzle or housing penetrates the vessel bottom head and include the safe ends welded to the nozzle or housing. Guidelines for repair design criteria are provided in BWRVIP-57 for instrumentation penetrations and BWRVIP-53 for SLC line.

Adequate aging management activities for these components also includes the monitoring and control of reactor coolant water chemistry in accordance with the guidelines in BWRVIP-130 (EPRI TR-1008192) or later revisions to ensure the long-term integrity and safe operation of BWR vessel internal components.

Evaluation and Technical Basis

91. ***Scope of Program:*** The scope of this program is applicable to BWR instrumentation nozzles and to BWR SLC nozzles/Core ΔP nozzles. The program manages cracking due to cyclic loading or stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC) using inspection and flaw evaluation in conformance with the guidelines of staff-approved BWRVIP-49A and BWRVIP-27A.

92. ***Preventive Actions:*** This program is a condition monitoring program and does not include preventative or mitigative measures. However, maintaining high water purity reduces susceptibility to SCC or IGSCC. Reactor coolant water chemistry is monitored and maintained in accordance with the guidelines in BWRVIP-130 (EPRI TR-1008192) or later revisions. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry."

93. Parameters Monitored/Inspected: The program manages the effects of cracking due to SCC/IGSCC on the intended function of BWR instrumentation nozzles and BWR SLC nozzles/Core ΔP nozzles. The program accomplishes this by inspection for cracks in accordance with the guidelines of approved BWRVIP-49A or BWRVIP-27A and the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI, Table IWB 2500-1 (2004 edition[10]).

94. ***Detection of Aging Effects:*** The evaluation guidelines of BWRVIP-49A and BWRVIP-27A recommend that the existing inspection requirements in ASME Code, Section XI, Table IWB-2500-1, are sufficient to monitor for indications of cracking in BWR instrumentation

[10] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of the ASME Code, Section XI.

nozzles and BWR SLC nozzles/Core ΔP nozzles and should continue to be followed for the period of extended operation. The extent and schedule of the inspection and test techniques prescribed by the ASME Section XI program are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component.

Instrument penetrations and SLC system nozzles or housings are inspected in accordance with the requirements in the ASME Code, Section XI, Table IWB-2500-1, examination categories B-D for full penetration nozzle-to-vessel welds, B-F for pressure-retaining dissimilar metal nozzle-to-safe end welds, or B-J for similar metal nozzle-to-safe end welds. In addition, these components are part of examination category B-P for pressure-retaining boundary. Collectively, these examination categories include volumetric examination methods (ultrasonic testing or radiography testing), surface examination methods (dye liquid penetrant testing or magnetic particle testing for ferritic components), and VT-2 visual examination methods.

95. ***Monitoring and Trending:*** Inspections scheduled in accordance with IWB-2400 and approved BWRVIP-49A or BWRVIP-27A provide timely detection of cracks. The scope of examination and reinspection is expanded beyond the baseline inspection if flaws are detected. Any indication detected is evaluated in accordance with ASME Section XI or other acceptable flaw evaluation criteria, such as the staff-approved BWRVIP-49A or BWRVIP-27A guidelines. Applicable and approved BWRVIP-14A, BWRVIP-59, and BWRVIP-60 documents provide additional guidelines for the evaluation of crack growth in stainless steels (SSs), nickel alloys, and low-alloy steels, respectively.

96. ***Acceptance Criteria:*** Acceptance criteria are given in BWRVIP-49A for instrumentation nozzles and BWRVIP-27A for BWR SLC nozzles/Core ΔP nozzles.

97. ***Corrective Actions:*** Repair and replacement procedures in staff-approved BWRVIP-57 and BWRVIP-53 are equivalent to those required in ASME Section XI. Guidelines for repair design criteria are provided in BWRVIP-57 for instrumentation penetrations and BWRVIP-53 for standby liquid control line. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-49A and BWRVIP-27A provides an acceptable level of quality in accordance with 10 CFR Part 50, Appendix B, corrective actions.

98. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds that licensee implementation of the guidelines in BWRVIP-49 and BWRVIP-27, as modified, provides an acceptable level of quality for inspection and flaw evaluation of the safety-related components addressed in accordance with the 10 CFR Part 50, Appendix B, confirmation process and administrative controls.

99. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

100. ***Operating Experience:*** Cracking due to SCC or IGSCC has occurred in BWR components made of austenitic SSs and nickel alloys. The program guidelines are based on an evaluation of available information, including BWR inspection data and information about the elements that cause IGSCC, to determine which locations may be susceptible to cracking. Implementation of the program provides reasonable assurance that cracking will be adequately managed so the intended functions of the instrument penetrations and SLC system nozzles or housings will be maintained consistent with the current licensing basis for the period of extended operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

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BWRVIP-03, (EPRI TR-105696 R1, March 30, 1999), *BWR Vessel and Internals Project, Reactor Pressure Vessel and Internals Examination Guidelines,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-03, July 15, 1999.

BWRVIP-14A, (EPRI TR-1016569), *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals,* September 2008.

BWRVIP-27A, (EPRI TR-107286, April 1997), *BWR Vessel and Internals Project, BWR Standby Liquid Control System/Core Plate ∆P Inspection and Flaw Evaluation Guidelines,* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-27 for Compliance with the License Renewal Rule (10 CFR Part 54), August 2003.

BWRVIP-130, (EPRI TR-1008192), *BWR Vessel and Internals Project*, *BWR Water Chemistry Guidelines-2004 Revision,* 2004.

BWRVIP-49A, (EPRI TR-108695, March 1998), *BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines,* Final License Renewal Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-49 for Compliance with the License Renewal Rule (10 CFR Part 54), March 2002.

BWRVIP-53, (EPRI TR-108716, March 24, 2000), *BWR Vessel and Internals Project, Standby Liquid Control Line Repair Design Criteria,* Initial Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-53, October 26, 2000.

BWRVIP-57, (EPRI TR-108721), *BWR Vessel and Internals Project, Instrument Penetration Repair Design Criteria,* March 24, 2000.

BWRVIP-59, (EPRI TR-108710), *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals*, March 24, 2000.

BWRVIP-60, (EPRI TR-108709, April 14, 2000), *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-62, (EPRI TR-108705), *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,* March 7, 2000.

BWRVIP-190, (EPRI TR-1016579), *BWR Vessel and Internals Project*, *BWR Water Chemistry Guidelines-2008 Revision,* October 2008.

XI.M10 BORIC ACID CORROSION

Program Description

The program relies in part on implementation of recommendations in Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-05 to monitor the condition of the reactor coolant pressure boundary for borated water leakage. Periodic visual inspection of adjacent structures, components, and supports for evidence of leakage and corrosion is an element of the NRC GL 88-05 monitoring program. Potential improvements to boric acid corrosion programs have been identified as a result of recent operating experience with cracking of certain nickel alloy pressure boundary components (NRC Regulatory Issue Summary 2003-013).

Borated water leakage from piping and components that are outside the scope of the program established in response to NRC GL 88-05 may affect structures and components that are subject to aging management review (AMR). Therefore, the scope of the monitoring and inspections of this program includes all components that contain borated water that are in proximity to structures and components that are subject to AMR. The scope of the evaluations, assessments, and corrective actions include all observed leakage sources and the affected structures and components.

Borated water leakage may be discovered by activities other than those established specifically to detect such leakage. Therefore, the program includes provisions for triggering evaluations and assessments when leakage is discovered by other activities.

Evaluation and Technical Basis

101. ***Scope of Program:*** The program covers any structures or components on which boric acid corrosion may occur (e.g., steel, copper alloy greater than 15 percent zinc, and aluminum) and electrical components on which borated reactor water may leak. The program includes provisions in response to the recommendations of NRC GL 88-05. The staff guidance of NRC GL 88-05 provides a program consisting of systematic measures to ensure that corrosion caused by leaking borated coolant does not lead to degradation of the leakage source or adjacent structures and components, and provides assurance that the reactor coolant pressure boundary will have an extremely low probability of abnormal leakage, rapidly propagating failure, or gross rupture. Such a program provides for (a) determination of the principal location of leakage, (b) examination requirements and procedures for locating small leaks, and (c) engineering evaluations and corrective actions to ensure that boric acid corrosion does not lead to degradation of the leakage source or adjacent structures or components, which could cause the loss of intended function of the structures or components.

102. ***Preventive Actions:*** This program is a condition monitoring program; thus, there are no preventive actions. However, minimizing reactor coolant leakage by frequent monitoring of the locations where potential leakage could occur and timely repair if leakage is detected prevents or mitigates boric acid corrosion.

103. ***Parameters Monitored/Inspected:*** The aging management program monitors the aging effects of loss of material due to boric acid corrosion on the intended function of an affected structure and component by detection of borated water leakage. Borated water leakage results in deposits of white boric acid crystals and the presence of moisture that can be observed by visual examination.

104. ***Detection of Aging Effects:*** Degradation of the component due to boric acid corrosion cannot occur without leakage of borated water. Conditions leading to boric acid corrosion, such as crystal buildup and evidence of moisture, are readily detectable by visual inspection, though removal of insulation may be required in some cases. However, for leakage examinations of components with external insulation surfaces and joints under insulation or not visible for direct visual examination, the surrounding area (including the floor, equipment surfaces, and other areas where leakage may be channeled) is examined for evidence of component leakage. Discoloration, staining, boric acid residue, and other evidence of leakage on insulation surfaces and the surrounding area are given particular consideration as evidence of component leakage. If evidence of leakage is found, removal of insulation to determine the exact source may be required. The program delineated in NRC GL 88-05 includes guidelines for locating small leaks, conducting examinations, and performing engineering evaluations. In addition, the program includes appropriate interfaces with other site programs and activities such that borated water leakage that is encountered by means other than the monitoring and trending established by this program is evaluated and corrected. Thus, the use of the NRC GL 88-05 program assures detection of leakage before the loss of the intended function of the affected components.

105. ***Monitoring and Trending:*** The program provides monitoring and trending activities as delineated in NRC GL 88-05, timely evaluation of evidence of borated water leakage identified by other means, and timely detection of leakage by observing boric acid crystals during normal plant walkdowns and maintenance.

106. ***Acceptance Criteria*****:** Any detected borated water leakage, white or discolored crystal buildup, or rust colored rust deposits are evaluated to confirm or restore the intended functions of affected structures and components consistent with the design basis prior to continued service.

107. ***Corrective Actions*****:** The NRC finds the requirements of 10 CFR Part 50, Appendix B, with additional consideration of the guidance in NRC GL 88-05, are acceptable to implement the corrective actions related to this program. Borated water leakage and areas of resulting boric acid corrosion are evaluated and corrected in conformance with the applicable provisions of NRC GL 88-05 and the corrective action program. Any detected boric acid crystal buildup or deposits should be cleaned. NRC GL 88-05 recommends that corrective actions to prevent recurrences of degradation caused by borated water leakage be included in the program implementation. These corrective actions include any modifications to be introduced in the present design or operating procedures of the plant that (a) reduce the probability of primary coolant leaks at locations where they may cause corrosion damage and (b) entail the use of suitable corrosion resistant materials or the application of protective coatings or claddings.

108. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

109. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

110. ***Operating Experience:*** Boric acid corrosion has been observed in nuclear power plants (NRC Information Notice [IN] 86-108 [and supplements 1 through 3] and NRC IN 2003-02) and has resulted in significant impairment of component intended functions in areas that are difficult to access/observe (NRC Bulletin 2002-01).

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, U.S. Nuclear Regulatory Commission, March 17, 1988.

NRC Information Notice 86-108, *Degradation of Reactor Coolant System Pressure Boundary Resulting from Boric Acid Corrosion*, U.S. Nuclear Regulatory Commission, December 26, 1986; Supplement 1, April 20, 1987; Supplement 2, November 19, 1987; and Supplement 3, January 5, 1995.

NRC Bulletin 2002-01: *Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,* U.S. Nuclear Regulatory Commission, March 18, 2002.

NRC Bulletin 2002-02: *Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,* U.S. Nuclear Regulatory Commission, August 9, 2002.

NRC Information Notice 2002-11: *Recent Experience with Degradation of Reactor Pressure Vessel Head,* U.S. Nuclear Regulatory Commission, March 12, 2002.

NRC Information Notice 2002-13: *Possible Indicators of Ongoing Reactor Pressure Vessel Head Degradation,* U.S. Nuclear Regulatory Commission, April 4, 2002.

NRC Information Notice 2003-02: *Recent Experience with Reactor Coolant System Leakage and Boric Acid Corrosion,* U.S. Nuclear Regulatory Commission, January 16, 2003.

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NUREG-1823, *U.S. Plant Experience with Alloy 600 Cracking and Boric Acid Corrosion of Light-Water Reactor Pressure Vessel Materials*, U.S. Nuclear Regulatory Commission, April 2005.

XI.M12 THERMAL AGING EMBRITTLEMENT OF CAST AUSTENITIC STAINLESS STEEL (CASS)

Program Description

The reactor coolant system components are inspected in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI. This inspection is augmented to detect the effects of loss of fracture toughness due to thermal aging embrittlement of cast austenitic stainless steel (CASS) components. This aging management program (AMP) includes determination of the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite. For "potentially susceptible" components, as defined below, aging management is accomplished through either (a) qualified inspections, such as enhanced visual examination (EVT-1); (b) a qualified ultrasonic testing (UT) methodology; or (c) a component-specific flaw tolerance evaluation in accordance with the American Society of Mechanical Engineers (ASME) Code, Section XI, 2004 edition[11]. Additional inspection or evaluations to demonstrate that the material has adequate fracture toughness are not required for components that are not susceptible to thermal aging embrittlement.

For pump casings and valve bodies, based on results of the assessment documented in the letter dated May 19, 2000, from Christopher Grimes, Nuclear Regulatory Commission (NRC), to Douglas Walters, Nuclear Energy Institute (NEI), screening for susceptibility to thermal aging embrittlement is not required for the pump casings and valve bodies. The existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate for all pump casings.

Evaluation and Technical Basis

111. ***Scope of Program:*** The program includes screening criteria to determine which CASS components are potentially susceptible to thermal aging embrittlement and require augmented inspection. The screening criteria are applicable to all primary pressure boundary components constructed from SA-351 Grades CF3, CF3A, CF8, CF8A, CF3M, CF3MA, and CF8M with service conditions above 250°C (482°F). The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis. For potentially susceptible piping components, aging management is accomplished either through (a) qualified inspections, such as enhanced visual examination (EVT-1); (b) a qualified UT methodology; or (c) a component-specific flaw tolerance evaluation. Aging management of PWR CASS reactor internal components is discussed in AMP XI.M16. Aging management of BWR CASS reactor internal components is discussed in AMP XI.M9.

Based on the criteria set forth in the May 19, 2000, NRC letter, the susceptibility to thermal aging embrittlement of CASS materials is determined in terms of casting method, molybdenum content, and ferrite content. For low-molybdenum content (0.5 weight percent [wt.%] maximum) steels, only static-cast steels with greater than 20 percent ferrite are potentially susceptible to thermal embrittlement. Static-cast low-molybdenum steels with less than or equal to 20 percent ferrite and all centrifugal-cast low-molybdenum steels are not susceptible. For high-molybdenum content (2.0 to 3.0 wt.%) steels, static-cast steels with greater than 14 percent ferrite and centrifugal-cast steels with greater than 20 percent ferrite

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[11] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

are potentially susceptible to thermal embrittlement. Static-cast high-molybdenum steels with less than or equal to14 percent ferrite and centrifugal-cast high-molybdenum steels with less than or equal to 20 percent ferrite are not susceptible. In the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factors (described in NUREG/CR-4513, Rev. 1) or a method producing an equivalent level of accuracy (plus or minus 6 percent deviation between measured and calculated values). A fracture toughness value of 255 kilojoules per square meter (kJ/m^2) (1,450 inches-pounds per square inch) at a crack depth of 2.5 millimeters (0.1 inch) is used to differentiate between CASS materials that are not susceptible and those that are potentially susceptible to thermal aging embrittlement. Extensive research data indicate that for CASS materials not susceptible to thermal aging embrittlement, the saturated lower-bound fracture toughness is greater than 255 kJ/m^2 (NUREG/CR-4513, Rev. 1).

For pump casings and valve bodies, screening for susceptibility to thermal aging embrittlement is not required (and thus there are no AMR line items). The staff's bounding integrity analysis shows that thermally aged CASS valve bodies and pump casings are resistant to failure. For all pump casings and valve bodies greater than a nominal pipe size (NPS) of 4 inches, the existing ASME Section XI inspection requirements, including the alternative requirements of ASME Code Case N-481 for pump casings, are adequate. ASME Section XI, Subsection IWB, requires only surface examination of valve bodies less than a NPS of 4 inches. For these valve bodies less than a NPS of 4 inches, the adequacy of inservice inspection (ISI) according to ASME Section XI has been demonstrated by an NRC-performed bounding integrity analysis (Reference letter from Christopher Grimes dated May 19, 2000).

112. ***Preventive Actions:*** The program consists of evaluation and inspection and provides no guidance on methods to mitigate thermal aging embrittlement.

113. ***Parameters Monitored/Inspected:*** The AMP monitors the effects of loss of fracture toughness on the intended function of the component by identifying the CASS materials that are susceptible to thermal aging embrittlement. For potentially susceptible materials, the program consists of either (a) qualified inspections, such as enhanced visual examination (EVT-1); (b) a qualified UT methodology; or (c) a plant- or component-specific flaw tolerance evaluation (loss of fracture toughness is of consequence only if cracks exist).

114. ***Detection of Aging Effects:*** For pump casings and valve bodies and "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. For "potentially susceptible" piping, because the base metal does not receive periodic inspection per ASME Section XI, the CASS AMP provides for qualified inspections of the base metal, such as enhanced visual examination (EVT-1) or a qualified UT methodology, with the scope of the inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examination methods that meet the criteria of the ASME Section XI, Appendix VIII, are acceptable. Alternatively, a plant- or component-specific flaw tolerance evaluation, using specific geometry, stress information, material properties, and ASME Code, Section XI can be used to demonstrate that the thermally-embrittled material has adequate toughness. Current UT methodology can not detect and size cracks; thus, EVT1 is used until newer and more effective UT methodology for CASS can be established. A description of EVT-1 is found in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 and Materials Reliability Program (MRP)-228.

115. ***Monitoring and Trending:*** Inspection schedules in accordance with IWB-2400 or IWC-2400, reliable examination methods, and qualified inspection personnel provide timely and reliable detection of cracks. If flaws are detected, the period of acceptability is determined from analysis of the flaw, depending on the crack growth rate and mechanism.

116. ***Acceptance Criteria:*** Flaws detected in CASS components are evaluated in accordance with the applicable procedures of IWB-3500 or IWC-3500. Flaw tolerance evaluation for components with ferrite content up to 25 percent is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20 percent ferrite in IWB-3641(b)(1). Extensive research data indicate that the lower-bound fracture toughness of thermally aged CASS materials with up to 25 percent ferrite is similar to that for SAWs with up to 20 percent ferrite (Lee et al., 1997). Flaw tolerance evaluation for piping with greater than 25 percent ferrite is performed on a case-by-case basis by using fracture toughness data provided by the applicant.

117. ***Corrective Actions:*** Repair and replacement are performed in conformance with IWA-4000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

118. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

119. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

120. ***Operating Experience:*** The AMP was developed by using research data obtained on both laboratory-aged and service-aged materials. Based on this information, the effects of thermal aging embrittlement on the intended function of CASS components will be effectively managed.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR Part 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2008.

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Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components*, May 19, 2000. (ADAMS Accession No. ML003717179)

NUREG/CR-4513, Rev. 1, *Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems*, U.S. Nuclear Regulatory Commission, August 1994.

BWRVIP-03, *BWR Vessel and Internals Project: Reactor Pressure Vessel and Internals Examination Guidelines* (EPRI TR-105696).

MRP-228, *Materials Reliability Program: Inspection Standard for PWR Internals,* 2009.

XI.M7 BWR STRESS CORROSION CRACKING

Program Description

The program to manage intergranular stress corrosion cracking (IGSCC) in boiling water reactor (BWR) coolant pressure boundary piping made of stainless steel (SS) and nickel based alloy components is delineated in NUREG-0313, Rev. 2, and Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-01 and its Supplement 1. The material includes base metal and welds. The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause IGSCC. These elements consist of a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. Sensitization of nonstabilized austenitic stainless steels containing greater than 0.03 weight percent carbon involves precipitation of chromium carbides at the grain boundaries during certain fabrication or welding processes. The formation of carbides creates a chromium depleted region that, in certain environments, is susceptible to stress corrosion cracking (SCC). Residual tensile stresses are introduced from fabrication processes, such as welding, surface grinding, or forming. High levels of dissolved oxygen or aggressive contaminants, such as sulfates or chlorides, accelerate the SCC processes. The program includes (a) preventive measures to mitigate IGSCC and (b) inspection and flaw evaluation to monitor IGSCC and its effects. The staff-approved boiling water reactor vessel and internals project (BWRVIP-75A) report allows for modifications to the inspection scope in the GL 88-01 program.

Evaluation and Technical Basis

121. ***Scope of Program:*** The program focuses on (a) managing and implementing countermeasures to mitigate IGSCC and (b) performing inservice inspection to monitor IGSCC and its effects on the intended function of BWR piping components. The program is applicable to all BWR piping and piping welds made of austenitic SS and nickel alloy that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93 degrees Celsius (200 degrees Fahrenheit) during power operation, regardless of code classification. The program also applies to pump casings, valve bodies, and reactor vessel attachments and appurtenances, such as head spray and vent components. NUREG-0313 and NRC GL 88-01, respectively, describe the technical basis and staff guidance regarding mitigation of IGSCC in BWRs. Attachment A of NRC GL 88-01 delineates the staff-approved positions regarding materials, processes, water chemistry, weld overlay reinforcement, partial replacement, stress improvement of cracked welds, clamping devices, crack characterization and repair criteria, inspection methods and personnel, inspection schedules, sample expansion, leakage detection, and reporting requirements.

122. ***Preventive Actions:*** The program delineated in NUREG-0313 and NRC GL 88-01 does not provide specific guidelines for controlling reactor water chemistry to mitigate IGSCC. Maintaining high water purity reduces susceptibility to SCC or IGSCC. The program description and evaluation and technical basis of monitoring and maintaining reactor water chemistry are addressed through implementation of Section XI.M2, “Water Chemistry.”

123. ***Parameters Monitored/Inspected:*** The program detects and sizes cracks and detects leakage by using the examination and inspection guidelines delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 or the referenced BWRVIP-75A guideline as approved by the NRC staff.

124. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 or BWRVIP-75A are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. The inspection guidance in approved BWRVIP-75A replaces the extent and schedule of inspection in NRC GL 88-01. The program uses volumetric examinations to detect IGSCC.

Inspection can reveal cracking and leakage of coolant. The extent and frequency of inspection recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce residual stresses, and how the weld was repaired if it had been cracked).

125. ***Monitoring and Trending:*** The extent and schedule for inspection, in accordance with the recommendations of NRC GL 88-01 or approved BWRVIP-75A guidelines, provide timely detection of cracks and leakage of coolant. Indications of cracking are evaluated and trended in accordance with the 2004[12] edition of the American Society of Mechanical Engineers (ASME) Code, Section XI, IWB-3100, against applicable acceptance standard criteria that are specified in the ASME Code, Section XI, IWB-3400 or IWB-3500. Applicable and approved BWRVIP-14A, BWRVIP-59A, BWRVIP-60, and BWRVIP-62 documents provide guidelines for evaluation of crack growth in SSs, nickel alloys, and low-alloy steels. An applicant may use BWRVIP-61 guidelines for BWR vessel and internals induction heating stress improvement effectiveness on crack growth in operating plants.

126. ***Acceptance Criteria:*** Any cracking is evaluated in accordance with IWB-3100 by comparing inspection results with the acceptance standards of IWB-3400 and IWB-3500.

127. ***Corrective Actions***: The guidance for weld overlay repair and stress improvement or replacement is provided in NRC GL 88-01. Corrective action is performed in accordance with IWA -4000-. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

128. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

129. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

130. ***Operating Experience:*** Intergranular SCC has occurred in small- and large-diameter BWR piping made of austenitic SS and nickel-base alloys. Cracking has occurred in recirculation, core spray, residual heat removal, control rod drive return line penetrations, and reactor water cleanup system piping welds (NRC GL 88-01, NRC Information Notices [INs] 82-39, 84-41, and 04-08). The comprehensive program outlined in NRC GL 88-01, NUREG-0313, and in the staff-approved BWRVIP-75A report addresses mitigating measures for SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an

[12] Refer to the GALL Report, Volume 2, Chapter 1, for applicability of other editions of ASME Code, Section XI.

aggressive environment). The GL 88-01 program has been effective in managing IGSCC in BWR reactor coolant pressure-retaining components, and the revision to the GL 88-01 program, according to the staff-approved BWRVIP-75A report, will adequately manage IGSCC degradation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Code Case N-504-1, *Alternative Rules for Repair of Class 1, 2, and 3 Austenitic Stainless Steel Piping*, Section XI, Division 1, 1995 edition, ASME Boiler and Pressure Vessel Code – Code Cases – Nuclear Components, American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition, American Society of Mechanical Engineers, New York, NY.

BWRVIP-14A, (EPRI TR- New number), *Evaluation of Crack Growth in BWR Stainless Steel RPV Internals,* September 2008.

BWRVIP-59A, (EPRI TR-new number), *Evaluation of Crack Growth in BWR Nickel-Base Austenitic Alloys in RPV Internals,* May 2007.

BWRVIP-60, (EPRI TR-108709, April 14, 2000), *BWR Vessel and Internals Project, Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,* Final Safety Evaluation Report by the Office of Nuclear Reactor Regulation for BWRVIP-60, July 8, 1999.

BWRVIP-61, (EPRI TR-112076), *BWR Vessel and Internals Induction Heating Stress Improvement Effectiveness on Crack Growth in Operating Reactors,* January 29, 1999.

BWRVIP-62, (EPRI TR-108705), *BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,* March 7, 2000.

BWRVIP-75A, (EPRI TR-new number), *Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313),* October 2005.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping*, U.S. Nuclear Regulatory Commission, January 25, 1988; Supplement 1, February 4, 1992.

NRC Information Notice 04-08, *Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds,* U.S. Nuclear Regulatory Commission, April 22, 2004.

NRC Information Notice 82-39, *Service Degradation of Thick Wall Stainless Steel Recirculation System Piping at a BWR Plant*, U.S. Nuclear Regulatory Commission, September 21, 1982.

NRC Information Notice 84-41, *IGSCC in BWR Plants*, U.S. Nuclear Regulatory Commission, June 1, 1984.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping*, W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

XI.M17 FLOW-AC CELERATED CORROSION

Program Description

The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R3 for an effective flow-accelerated corrosion (FAC) program. The program includes performing (a) an analysis to determine critical locations, (b) limited baseline inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.

NSAC-202L-R3 provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R3 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, for development of procedures and control of special processes.

Evaluation and Technical Basis

131. ***Scope of Program:*** The FAC program, described by the EPRI guidelines in NSAC-202L-R3 (May 2006), includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two-phase as well as single-phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter 89-08.

132. ***Preventive Actions:*** The FAC program is an analysis, inspection, and verification program; no preventive action has been recommended in this program. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAC.

133. ***Parameters Monitored/Inspected:*** The aging management program monitors the effects of loss of material due to FAC on the intended function of piping and components by measuring wall thickness.

134. ***Detection of Aging Effects:*** Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L-R3 consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic or radiographic testing is used to detect wall thinning. A representative sample of components are selected based on the most susceptible locations for wall thickness measurement once every refueling outage. The extent and schedule of the inspections ensure detection of wall thinning before the loss of intended function.

135. ***Monitoring and Trending:*** CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions. CHECWORKS is acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides reasonable assurance that structural integrity will be maintained between inspections. Inspection results are evaluated to determine if additional inspections are needed to ensure that the extent of wall thinning is adequately determined, ensure that intended function will not be lost, and identify corrective actions. Previous loss of material predictions rates due to FAC may change after a power uprate is implemented.

136. ***Acceptance Criteria:*** Inspection results are input for a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, corrective action should be considered.

137. ***Corrective Actions:*** Prior to service, components for which the acceptance criteria are not satisfied are reevaluated, repaired, or replaced. Long-term corrective actions could include adjusting operating parameters or selecting materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

138. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

139. ***Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

140. ***Operating Experience:*** Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notice [IN] 81-28, IN 92-35, IN 95-11, IN 2006-08) and in two-phase piping in extraction steam lines (NRC IN 89-53, IN 97-84) and moisture separation reheater and feedwater heater drains (NRC IN 89-53, IN 91-18, IN 93-21, IN 97-84). Observed wall thinning may be due to mechanisms other than FAC, which require alternate materials to resolve the issue (Licensee Event Report 50-237/2007-003-00). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR Part 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*, U.S. Nuclear Regulatory Commission, May 2, 1989.

NRC IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, July 9, 1987.

NRC Information Notice 81-28, *Failure of Rockwell-Edward Main Steam Isolation Valves*, U.S. Nuclear Regulatory Commission, September 3, 1981.

NRC Information Notice 89-53, *Rupture of Extraction Steam Line on High Pressure Turbine*, U.S. Nuclear Regulatory Commission, June 13, 1989.

NRC Information Notice 91-18, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, March 12, 1991.

NRC Information Notice 91-18, Supplement 1, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, December 18, 1991.

NRC Information Notice 92-35, *Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor*, U.S. Nuclear Regulatory Commission, May 6, 1992.

NRC Information Notice 93-21, *Summary of NRC Staff Observations Compiled during Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs*, U.S. Nuclear Regulatory Commission, March 25, 1993.

NRC Information Notice 95-11, *Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device*, U.S. Nuclear Regulatory Commission, February 24, 1995.

NRC Information Notice 97-84, *Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion*, U.S. Nuclear Regulatory Commission, December 11, 1997.

NSAC-202L-R2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, (1011838) Electric Power Research Institute, Nuclear Safety Analysis Center, Palo Alto, CA, April 8, 1999.

NSAC-202L-R3, *Recommendations for an Effective Flow Accelerated Corrosion Program*, Electric Power Research Institute, Nuclear Safety Analysis Center, Palo Alto, CA, May 2006.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants*, P. C. Wu, U.S. Nuclear Regulatory Commission, April 1989.

NRC Information Notice 2006-08, *Secondary Piping Rupture at the Mihama Power Station in Japan*, U.S. Nuclear Regulatory Commission, March 16, 2006.

NRC Licensee Event Report 50‑237/2007‑003‑00, *Unit 2 High Pressure Coolant Injection System Declared Inoperable*, U.S. Nuclear Regulatory Commission, September 24, 2007.

XI.M18 BOLTING INTEGRITY

Program Description

The program focuses on closure bolting for pressure retaining components and relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program also relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213.

The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Aging management program (AMP) XI.M1, “ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD,” includes inspection of safety-related and non-safety-related closure bolting and supplements this bolting integrity program. AMPs XI.S1, “ASME Section XI, Subsection IWE”; XI.S3, “ASME Section XI, Subsection IWF”; and XI.M23, “Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems,” manage inspection of safety-related and non-safety related structural bolting.

Evaluation and Technical Basis

141. ***Scope of Program:*** This program covers closure bolting for pressure retaining components within the scope of license renewal, including both safety-related and non-safety-related bolting. The aging management of reactor head closure studs is addressed by AMP XI.M3 and is not included in this program.

142. ***Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769 and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting. NUREG-1339 takes exception to certain items in EPRI NP-5769 and recommends additional measures with regard to them. Of particular note, use of molybdenum disulfide (MoS_2) as a lubricant has been shown to be a potential contributor to stress corrosion cracking (SCC) and should not be used. Preventive measures also include using bolting material that has an actual measured yield strength limited to less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch [ksi]). Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation.

143. ***Parameters Monitored/Inspected:*** This program monitors the effects of aging on the intended function of bolting. Specifically, bolting for safety-related pressure retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss or prestress. Bolting for other pressure retaining components is inspected for signs of leakage.

High strength closure bolting (actual yield strength greater than or equal to 1,034 MPa [150 ksi]), if used, should be monitored for cracking.

144. ***Detection of Aging Effects:*** The American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program implements inspection of Class 1, Class 2, and Class 3 pressure retaining bolting in accordance with requirements of ASME Code Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1. These include volumetric and visual (VT-1) examinations, as appropriate. In addition, for both ASME Code class bolting and non-ASME Code class bolting, periodic system walkdowns and inspections (at least once per refueling cycle) ensure detection of leakage at bolted joints before the leakage becomes excessive. Bolting inspections should include consideration of the guidance applicable for pressure boundary bolting in NUREG-1339 and in EPRI NP-5769 and EPRI TR-104213.

Degradation of pressure boundary closure bolting due to crack initiation, loss of preload, or loss of material may result in leakage from the mating surfaces or joint connections of pressure boundary components. Periodic inspection of pressure boundary components for signs of leakage ensures that age-related degradation of closure bolting is detected and corrected before component leakage becomes excessive. Accordingly, pressure retaining bolted connections should be inspected at least once per refueling cycle. The inspections may be performed as part of ASME Code Section XI leakage tests or as part of other periodic inspection activities such as system walkdowns or an external surfaces monitoring program.

High strength closure bolting (actual yield strength greater than or equal to 1,034 MPa [150 ksi]), may be subject to stress corrosion cracking. For high strength closure bolts in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed in addition to visual examination. This volumetric examination may be waived with adequate plant-specific justification.

145. ***Monitoring and Trending:*** The inspection schedules of ASME Section XI are effective and ensure timely detection of applicable aging effects. If bolting connections for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to an inspection frequency based on evaluation in accordance with the corrective action process.

146. ***Acceptance Criteria:*** Any indications of aging effects in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. For other pressure retaining bolting, indications of aging should be dispositioned in accordance with the corrective action process.

147. ***Corrective Actions:*** Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI NP-5769. Replacement of other pressure retaining bolting (i.e., non-ASME code class bolting) is performed in accordance with the guidelines and recommendations of EPRI TR-104213. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

148. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report,

the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

149. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

150. ***Operating Experience:*** Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (U.S. Nuclear Regulatory Commission [NRC] IE Bulletin 82-02, NRC Generic Letter 91-17). SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with commitments made in response to NRC communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI NP-5769 and TR-104213 and represent industry consensus.

Degradation related failures have occurred in downcomer Tee-quencher bolting in boiling water reactors (BWRs) designed with drywells (ADAMS Accession Number ML050730347). Leakage from bolted connections has been observed in reactor building closed cooling systems of BWRs (LER 50-341/2005-001).

The applicant is to evaluate applicable operating experience to support the conclusion that the effects of aging are adequately managed.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2009.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition[1] (no addenda), American Society of Mechanical Engineers, New York, NY.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric Power Research Institute, December 1995.

NRC Generic Letter 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

[1] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

NRC Morning Report, *Failure of Safety/Relief Valve Tee-Quencher Support Bolts*, March 14, 2005. (ADAMS Accession Number ML050730347)

NUREG-1339, Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants, U.S. Nuclear Regulatory Commission, June 1990.

XI.M19 STEAM GENERATORS

Program Description

The Steam Generator program is applicable to managing the aging of steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals).

The establishment of a steam generator program for ensuring steam generator tube integrity is required by plant technical specifications. The technical specifications at each plant are modeled after the standard technical specifications of NUREG-1430, Volume 1, Rev. 3, for Babcock & Wilcox pressurized water reactors (PWRs); NUREG-1431, Volume 1, Rev. 3, for Westinghouse PWRs; and NUREG-1432, Volume 1, Rev. 3, for Combustion Engineering PWRs. The requirements pertaining to steam generators in these three versions of the standard technical specifications are essentially identical. The technical specifications require tube integrity to be maintained and specify performance criteria, condition monitoring requirements, inspection scope and frequency, acceptance criteria for the plugging or repair of flawed tubes, acceptable repair methods, and leakage monitoring requirements.

The nondestructive examination techniques used to inspect tubes, plugs, sleeves, and secondary side internals are intended to identify components (e.g., tubes, plugs) with degradation that may need to be removed from service or repaired.

The Steam Generator program is modeled after Nuclear Energy Institute (NEI) 97-06, Revision 2, "Steam Generator Program Guidelines." This program references a number of industry guidelines and incorporates a balance of prevention, mitigation, inspection, evaluation, repair, and leakage monitoring measures. The NEI 97-06 document (a) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis and (b) provides guidance for monitoring and maintaining the tubes to provide assurance that the performance criteria are met at all times between scheduled inspections of the tubes. Steam generator tube integrity can be affected by degradation of steam generator plugs, sleeves, and secondary side internals. Therefore, all these components are addressed by this aging management program (AMP). When properly implemented, the NEI 97-06 program can be effective at managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side internals.

Evaluation and Technical Basis

151. ***Scope of Program:*** This program addresses degradation associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals). It does not cover degradation associated with the steam generator shell, channelhead, nozzles, or the welds associated with these components.

152. ***Preventive Actions:*** This program includes preventive and mitigative actions for addressing degradation. Preventive and mitigative measures that are part of the Steam Generator program include primary- and secondary-side water chemistry programs, foreign material exclusion programs, and other primary and secondary side maintenance activities. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on the Electric Power Research Institute (EPRI) PWR Primary Water Chemistry Guidelines and the EPRI PWR Secondary Water Chemistry Guidelines. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, “Water Chemistry,” of this report. The program also includes foreign material exclusion as a means to inhibit wear degradation and secondary side maintenance activities such as sludge lancing and chemical cleaning for removing deposits that may contribute to degradation. Guidance on foreign material exclusion is provided in NEI 97-06. Guidance on maintenance of secondary side integrity is provided in the EPRI Steam Generator Integrity Assessment Guidelines. Primary side preventive maintenance activities include replacing plugs made with corrosion susceptible materials with more corrosion resistant materials and preventively plugging tubes susceptible to degradation.

153. ***Parameters Monitored/Inspected:*** There are currently three types of steam generator tubing used in the United States: mill annealed Alloy 600, thermally treated Alloy 600, and thermally treated Alloy 690. Mill annealed Alloy 600 steam generator tubes have experienced degradation due to corrosion (e.g., primary water stress corrosion cracking, outside diameter stress corrosion cracking, intergranular attack, pitting, wastage) and mechanically induced phenomena (e.g., denting, wear, impingement damage, fatigue). Thermally treated Alloy 600 steam generator tubes have experienced degradation due to corrosion (primarily cracking) and mechanically induced phenomena (primarily wear). Thermally treated Alloy 690 tubes have only experienced tube degradation due to mechanically induced phenomena (primarily wear). Degradation of tube plugs, sleeves, and secondary side internals have also been observed depending, in part, on the material of construction of the specific component.

The program includes an assessment of the forms of degradation to which a component is susceptible and implementation of inspection techniques capable of detecting those forms of degradation. The parameter monitored is specific to the component and the acceptance criteria for the inspection. For example, the severity of tube degradation may be evaluated in terms of the depth of degradation or measured voltage, dependent on whether a depth-based or voltage-based tube repair criteria (acceptance criteria) is being implemented for that specific degradation mechanism. Other parameters monitored include signals of excessive deposit buildup (e.g., steam generator water level oscillations), which may result in fatigue failure of tubes or corrosion of the tubes; water chemistry parameters, which may indicate unacceptable levels of impurities; primary-to-secondary leakage, which may indicate excessive tube, plug, or sleeve degradation; and the presence of loose parts or foreign objects on the primary and secondary side of the steam generator, which may result in tube damage.

Water chemistry parameters are also monitored as discussed in Chapter XI.M2. The EPRI PWR Steam Generator Primary-to-Secondary Leakage Guidelines (EPRI report 1008219) provides guidance on monitoring primary-to-secondary leakage. The EPRI Steam Generator Integrity Assessment Guidelines (EPRI report 1012987) provide guidance on secondary side activities.

In summary, the NEI 97-06 program (which references the EPRI guidelines) provides guidance on parameters to be monitored or inspected.

154. ***Detection of Aging Effects:*** The technical specifications require a Steam Generator program be established and implemented to ensure steam generator tube integrity is maintained. This requirement ensures that components that could compromise tube integrity are properly evaluated or monitored (e.g., degradation of a secondary side component that could result in a loss of tube integrity is managed by the Steam Generator program). The inspection requirements in the technical specifications are intended to detect tube and sleeve degradation (i.e., aging effects), if they should occur.

The technical specifications are performance-based, and the actual scope of the inspection and the expansion of sample inspections are justified based on the results of the inspections. The goal is to perform inspections at a frequency sufficient to provide reasonable assurance of steam generator tube integrity for the period of time between inspections.

The general condition of some components (e.g., plugs and secondary side components) may be monitored visually and subsequently, more detailed inspections may be performed if degradation is detected.

NEI 97-06 provides additional guidance on inspection programs to detect degradation of tubes, sleeves, plugs, and secondary side internals. The frequencies of the inspections are based on technical assessments. Guidance on performing these technical assessments is contained in NEI 97-06 and the associated industry guidelines.

The inspections and monitoring are performed by qualified personnel using qualified techniques in accordance with approved procedures. The EPRI PWR Steam Generator Examination Guidelines (EPRI Report 1013706) contains guidance on the qualification of steam generator tube inspection techniques.

The primary-to-secondary leakage monitoring program provides a potential indicator of a loss of steam generator tube integrity. NEI 97-06 and the associated EPRI guidelines provide information pertaining to an effective leakage monitoring program.

Extensive deposit buildup in the steam generators can be indicative of a condition that could affect tube integrity. The EPRI Steam Generator Integrity Assessment Guidelines provide guidance on maintenance on the secondary side of the steam generator, including secondary side cleaning.

155. ***Monitoring and Trending:*** Condition monitoring assessments are performed to determine whether the structural and accident induced leakage performance criteria were satisfied during the prior operating interval. Operational assessments are performed to verify that structural and leakage integrity will be maintained for the planned operating interval before the next inspection. If tube integrity can not be maintained for the planned operating interval before the next inspection, corrective actions are taken in accordance with the plant's corrective action program. Comparisons of the results of the condition monitoring assessment to the predictions of the previous operational assessment are performed to evaluate the adequacy of the previous operational assessment methodology. If the operational assessment was not conservative in terms of the number and/or severity of the condition, corrective actions are taken in accordance with the plant's corrective action program.

For tubes and sleeves, the technical specifications require condition monitoring and operational assessments to be performed (although the technical specifications do not explicitly require operational assessments, they are required implicitly by the need to maintain tube integrity for the period of time between inspections). NEI 97-06 provides guidance on performing condition monitoring and operational assessments by referencing the EPRI Steam Generator Integrity Assessment Guidelines.

The goal of the inspection program for all components covered by this AMP is to ensure the components continue to function consistent with the design and licensing basis of the facility (including regulatory safety margins).

NEI 97-06 also provides guidance on the purpose of the assessments of steam generator secondary side internals degradation by reference to the EPRI Steam Generator Integrity Assessment Guidelines.

156. ***Acceptance Criteria:*** Assessment of tube and sleeve integrity and plugging or repair criteria of flawed and sleeved tubes is in accordance with plant technical specifications. The criteria for plugging or repairing steam generator tubes and sleeves are based on U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.121 or other criteria previously reviewed and approved by the staff and incorporated into plant technical specifications. Guidance on assessing the acceptability of flaws is also provided in NEI 97-06 and the associated EPRI guidelines, including the EPRI Steam Generator In Situ Pressure Test Guidelines and EPRI Steam Generator Integrity Assessment Guidelines.

Degraded plugs and degraded secondary side internals in the steam generator are evaluated for continued acceptability on a case-by-case basis. NEI 97-06 and the associated EPRI guidelines provide additional guidance on these areas. The intent of these evaluations is to ensure the component has adequate integrity consistent with the design and licensing basis of the facility. In addition, the acceptability of leaving a loose part or a foreign object in the steam generator is evaluated on a case-by-case basis. The intent of these evaluations is to ensure the component(s) affected by these parts/objects will maintain adequate integrity consistent with the design and licensing basis of the facility.

Guidance on the acceptability of primary-to-secondary leakage and water chemistry parameters are also discussed in NEI 97-06 and the associated EPRI guidelines.

157. ***Corrective Actions:*** For degradation of steam generator tubes and sleeves (if applicable), the technical specifications provide requirements on the actions to be taken when the acceptance criteria are not met. For degradation of other components, the appropriate corrective action is evaluated per NEI 97-06 and the associated EPRI guidelines, the American Society of Mechanical Engineers (ASME) Code Section XI (2004 Edition)[14], 10 CFR 50.65, and 10 CFR Part 50, Appendix B, as appropriate. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable for ensuring effective corrective actions.

158. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

In addition, the adequacy of the preventive measures in the Steam Generator program is confirmed through periodic inspections.

[14] Refer to GALL Report Volume 2, Chapter 1, for applicability of other editions of the ASME Code.

159. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

160. ***Operating Experience:*** Several generic communications have been issued by the NRC related to the steam generator programs implemented at plants. The reference section lists many of these generic communications. In addition, NEI 97-06 provides guidance to the industry for routinely sharing pertinent steam generator operating experience and for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06. The latter includes providing interim guidance to the industry, when needed.

When properly implemented, the NEI 97-06 program can be effective at managing the aging effects associated with steam generator tubes, plugs, sleeves, and secondary side components that are contained within the steam generator (i.e., secondary side internals) such that the steam generators can perform their intended safety function.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR Part 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2009.

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2009.

EPRI 1008219, *PWR Primary-to-Secondary Leak Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, December 2004.

EPRI 1012987, *Steam Generator Integrity Assessment Guidelines: Revision 2*, Electric Power Research Institute, Palo Alto, CA, July 2006.

EPRI 1013706, *PWR Steam Generator Examination Guidelines: Revision 7*, Electric Power Research Institute, Palo Alto, CA, October 2007.

EPRI 1014983, *Steam Generator In Situ Pressure Test Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, August 2007.

EPRI 1014986, *Pressurized Water Reactor Primary Water Chemistry Guidelines: Revision 6*, Electric Power Research Institute, Palo Alto, CA, December 2007.

EPRI 1016555, *Pressurized Water Reactor Secondary Water Chemistry Guidelines: Revision 7*, Electric Power Research Institute, Palo Alto, CA, February 2009.

NEI 97-06, Rev. 2, *Steam Generator Program Guidelines*, Nuclear Energy Institute, September 2005.

NRC Bulletin 88-02, *Rapidly Propagating Cracks in Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, February 5, 1988.

NRC Bulletin 89-01, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, May 15, 1989.

NRC Bulletin 89-01, Supplement 1, *Failure of Westinghouse Steam Generator Tube Mechanical Plugs*, U.S. Nuclear Regulatory Commission, November 14, 1990.

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NRC Draft Regulatory Guide DG-1074, *Steam Generator Tube Integrity*, U.S. Nuclear Regulatory Commission, December 1998.

NRC Regulatory Guide, 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, August 1976.

NRC Generic Letter 95-03, *Circumferential Cracking of Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, April 28, 1995.

NRC Generic Letter 95-05, *Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking*, U.S. Nuclear Regulatory Commission, August 3, 1995.

NRC Generic Letter 97-05, *Steam Generator Tube Inspection Techniques*, U.S. Nuclear Regulatory Commission, December 17, 1997.

NRC Generic Letter 97-06, *Degradation of Steam Generator Internals*, U.S. Nuclear Regulatory Commission, December 30, 1997.

NRC Generic Letter 2004-01, *Requirements for Steam Generator Tube Inspections*, U.S. Nuclear Regulatory Commission, August 30, 2004.

NRC Generic Letter 2006-01, *Steam Generator Tube Integrity and Associated Technical Specifications*, U.S. Nuclear Regulatory Commission, January 20, 2006.

NRC Information Notice 88-99, *Detection and Monitoring of Sudden and/or Rapidly Increasing Primary-to-Secondary Leakage*, U.S. Nuclear Regulatory Commission, December 20, 1988.

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NRC Information Notice 2003-13, *Steam Generator Tube Degradation at Diablo Canyon*, U.S. Nuclear Regulatory Commission, August 28, 2003.

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XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system is managed for the extended period of operation. NRC GL 89-13 defines the OCCW system as a system or systems that transfer heat from safety-related structures, systems, and components (SSCs) to the ultimate heat sink (UHS). The guidelines of NRC GL 89-13 for managing an OCCW include: (a) surveillance and control of biofouling (see Chapter IX of NUREG-1801); (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, sediment deposition (silting), and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walkdown inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.

In accordance with guidance of NRC GL 89-13, the OCCW aging management program manages aging effects of components in raw water systems, such as the service water or river water, by using a combination of preventive, condition, and performance monitoring activities. These include (a) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system; (b) inspection of critical components for signs of corrosion, erosion, and biofouling; and (c) testing the heat transfer capability of heat exchangers that remove heat from components important to safety.

For buried OCCW piping, the aging effects on the external surfaces are managed by XI.M28 or XI.M34, but the internal surfaces are managed by this program.

Evaluation and Technical Basis

161. ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms generally found in OCCW systems and OCCW steel piping components with or without protective coating as committed to in response to NRC GL 89-13. OCCW systems, as defined by NRC GL 89-13, include the service water system and any other cooling system exposed to raw water that transfers heat from safety-related SSCs to the UHS. The aging management of closed-cycle cooling water (CCCW) systems is described in XI.M21 “Closed-Cycle Cooling Water System,” and is not included as part of this program. The OCCW System program applies to components constructed of various materials, including steel, stainless steel, aluminum, copper alloys, polymeric materials, and concrete. Piping may be lined with internal coatings or unlined.

162. ***Preventive Actions:*** Preventive actions begin with the use of appropriate material for construction. Steel piping system components are typically lined or coated to protect the underlying metal surfaces from exposure to corrosive cooling water environments. Implementation of NRC GL 89-13 includes control or preventive measures, such as chemical treatment, whenever the potential for biological fouling exists or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically-influenced corrosion (MIC) and buildup of macroscopic biological fouling debris from biota, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and debris or silt.

163. ***Parameters Monitored/Inspected:*** This program manages the aging effects, such as loss of heat transfer capability, loss of material, and corrosion effects, through preventive, condition, and performance monitoring. Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure their heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

164. ***Detection of Aging Effects:*** Inspections, surveillance, and testing are done in accordance with the applicant's commitments to NRC GL 89-13. Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, and eddy current testing are effective methods to measure surface conditions or the extent of wall thinning associated with the service water system piping and components. Inspection scope, methods (e.g., visual or nondestructive examination), and testing frequencies are in accordance with the applicant's commitments under NRC GL 89-13. Inspections or nondestructive testing determines the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable.

165. ***Monitoring and Trending:*** Heat transfer testing results are documented in plant test procedures and are trended in accordance with commitments to NRC GL 89-13. Corrosion in these systems should be evaluated for impact on the remaining wall thickness of the component, and if occlusion is noted, also evaluated for impact on the heat transfer capability of the system.

166. ***Acceptance Criteria:*** The acceptance criteria are in accordance with the applicant's commitments to NRC GL 89-13. Corrosion, erosion, and biofouling can cause significant loss of material in components. Inspected components should exhibit adequate design margin regarding design dimensions (e.g., minimum required wall thickness). As applicable, coatings or linings should be intact to protect the underlying metal. Heat removal capability is within allowable values for the system and components tested, in accordance with NRC GL 89-13.

167. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria, and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

168. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process controls.

169. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

170. ***Operating Experience:*** Significant microbiologically-influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for more than 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems. [Note - Recent operating experience indicates that loss of material due to microbiologically influenced corrosion may be occurring in some OCCW systems in spite of the programs associated with GL 89-13 and this aging management program. The staff is considering whether additional actions should be taken by plants which have experienced loss of material in OCCW systems.]

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

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NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, U.S. Nuclear Regulatory Commission, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, U.S. Nuclear Regulatory Commission, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, U.S. Nuclear Regulatory Commission, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems*, U.S. Nuclear Regulatory Commission, November 20, 1986.

NRC Information Notice 2004-07, *Plugging of Safety Injection Pump Lubrication Oil Coolers With Lakeweed*, U.S. Nuclear Regulatory Commission, April 7, 2004.

NRC Information Notice 2007-28*, Potential Common Cause Vulnerabilities in Essential Service Water Systems Due to Inadequate Chemistry Controls*, U.S. Nuclear Regulatory Commission, September 17, 2007.

XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system is managed for the extended period of operation. NRC GL 89-13 defines the OCCW system as a system or systems that transfer heat from safety-related structures, systems, and components (SSCs) to the ultimate heat sink (UHS). The guidelines of NRC GL 89-13 for managing an OCCW include: (a) surveillance and control of biofouling (see Chapter IX of NUREG-1801); (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, sediment deposition (silting), and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walkdown inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.

In accordance with guidance of NRC GL 89-13, the OCCW aging management program manages aging effects of components in raw water systems, such as the service water or river water, by using a combination of preventive, condition, and performance monitoring activities. These include (a) surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system; (b) inspection of critical components for signs of corrosion, erosion, and biofouling; and (c) testing the heat transfer capability of heat exchangers that remove heat from components important to safety.

For buried OCCW piping, the aging effects on the external surfaces are managed by XI.M28 or XI.M34, but the internal surfaces are managed by this program.

Evaluation and Technical Basis

171. ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms generally found in OCCW systems and OCCW steel piping components with or without protective coating as committed to in response to NRC GL 89-13. OCCW systems, as defined by NRC GL 89-13, include the service water system and any other cooling system exposed to raw water that transfers heat from safety-related SSCs to the UHS. The aging management of closed-cycle cooling water (CCCW) systems is described in XI.M21 “Closed-Cycle Cooling Water System,” and is not included as part of this program. The OCCW System program applies to components constructed of various materials, including steel, stainless steel, aluminum, copper alloys, polymeric materials, and concrete. Piping may be lined with internal coatings or unlined.

172. ***Preventive Actions:*** Preventive actions begin with the use of appropriate material for construction. Steel piping system components are typically lined or coated to protect the underlying metal surfaces from exposure to corrosive cooling water environments. Implementation of NRC GL 89-13 includes control or preventive measures, such as chemical treatment, whenever the potential for biological fouling exists or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically-influenced corrosion (MIC) and buildup of macroscopic biological fouling debris from biota, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and debris or silt.

173. ***Parameters Monitored/Inspected:*** This program manages the aging effects, such as loss of heat transfer capability, loss of material, and corrosion effects, through preventive, condition, and performance monitoring. Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure their heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

174. ***Detection of Aging Effects:*** Inspections, surveillance, and testing are done in accordance with the applicant's commitments to NRC GL 89-13. Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, and eddy current testing are effective methods to measure surface conditions or the extent of wall thinning associated with the service water system piping and components. Inspection scope, methods (e.g., visual or nondestructive examination), and testing frequencies are in accordance with the applicant's commitments under NRC GL 89-13. Inspections or nondestructive testing determines the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable.

175. ***Monitoring and Trending:*** Heat transfer testing results are documented in plant test procedures and are trended in accordance with commitments to NRC GL 89-13. Corrosion in these systems should be evaluated for impact on the remaining wall thickness of the component, and if occlusion is noted, also evaluated for impact on the heat transfer capability of the system.

176. ***Acceptance Criteria:*** The acceptance criteria are in accordance with the applicant's commitments to NRC GL 89-13. Corrosion, erosion, and biofouling can cause significant loss of material in components. Inspected components should exhibit adequate design margin regarding design dimensions (e.g., minimum required wall thickness). As applicable, coatings or linings should be intact to protect the underlying metal. Heat removal capability is within allowable values for the system and components tested, in accordance with NRC GL 89-13.

177. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria, and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

178. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process controls.

179. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

180. ***Operating Experience:*** Significant microbiologically-influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for more than 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems. [Note - Recent operating experience indicates that loss of material due to microbiologically influenced corrosion may be occurring in some OCCW systems in spite of the programs associated with GL 89-13 and this aging management program. The staff is considering whether additional actions should be taken by plants which have experienced loss of material in OCCW systems.]

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, U.S. Nuclear Regulatory Commission, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, U.S. Nuclear Regulatory Commission, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, U.S. Nuclear Regulatory Commission, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems*, U.S. Nuclear Regulatory Commission, November 20, 1986.

NRC Information Notice 2004-07, *Plugging of Safety Injection Pump Lubrication Oil Coolers With Lakeweed*, U.S. Nuclear Regulatory Commission, April 7, 2004.

NRC Information Notice 2007-28*, Potential Common Cause Vulnerabilities in Essential Service Water Systems Due to Inadequate Chemistry Controls*, U.S. Nuclear Regulatory Commission, September 17, 2007.

XI.M21A TREATED WATER SYSTEMS

Program Description

Nuclear power plants contain many closed, treated water systems. These systems undergo water treatment to control water chemistry and prevent corrosion (i.e., they are treated water systems). These systems are also recirculating systems in which the rate of recirculation is much higher than the rate of addition of makeup water (i.e., they are closed systems). The program includes (a) water treatment, including the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion and/or cracking. Depending on the industry standard selected for use in association with this aging management program (AMP) and/or plant operating experience, this program also may include corrosion monitoring (e.g., corrosion coupon testing) and microbiological testing.

Evaluation and Technical Basis

181. ***Scope of Program:*** This program manages the aging effects of loss of material from and cracking due to corrosion and/or stress corrosion cracking of the internal surfaces of piping, piping components, and piping elements fabricated from any material and exposed to treated water. Not included are those piping systems that are managed by another AMP. Examples of systems managed by this AMP include closed-cycle cooling water systems (as defined by NRC GL 89-13[15]), closed portions of heating, ventilation, and air conditioning systems, and auxiliary boiler systems. Examples of systems not addressed by this AMP include BWR coolant, PWR primary and secondary water, and PWR/BWR condensate systems. Aging in these systems is managed by the water chemistry AMP (XI.M2) and American Society of Mechanical Engineers (ASME) Section XI, Inservice Inspection Subsections IWB, IWC, and IWD AMP (XI.M1). Treated fire water systems, if present, are also not included in this AMP. The water used in systems covered by this AMP may, but need not, be demineralized. The water used in systems covered by this AMP receives chemical treatment including corrosion inhibitors. Untreated water systems are addressed using other AMPs, such as Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (XI.M38).

182. ***Preventive Actions:*** This program mitigates the occurrence of the aging effects “loss of material” and “cracking” that are due to corrosion and stress corrosion cracking through water treatment. The water treatment program includes corrosion inhibitors and is designed to maintain the function of associated equipment and minimize the corrosivity of the water.

183. ***Parameters Monitored:*** This program monitors water chemistry (preventive monitoring) and the visual appearance of surfaces exposed to the water (condition monitoring). Depending on the industry standard selected for use in association with this AMP and/or plant operating experience, this program may also include corrosion monitoring (e.g., corrosion coupon testing) and microbiological testing. These parameters are monitored because maintenance of optimal water chemistry prevents loss of material and cracking due

[15] Generic Letter (GL) 89-13 defines a service water system as “the system or systems that transfer heat from safety-related structures, systems, or components to the ultimate heat sink.” GL 89-13 further defines a closed-cycle system as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled and on which heat is not directly rejected to an ultimate heat sink.

to corrosion and stress corrosion cracking. In addition, the visual appearance of surfaces provides evidence of the existence of loss of material or cracking. The specific water chemistry parameters monitored and the acceptable range of values for these parameters are in accordance with industry standard guidance documents such as, but not limited to, documents produced by the Electric Power Research Institute (EPRI), the American Society of Heating Refrigeration and Air-Conditioning Engineers, the Cooling Technology Institute, the American Boiler Manufacturer's Association, or the ASME. For closed-cycle cooling water systems as defined in GL 89-13, EPRI TR-1007820 is used. For other systems, the applicant selects an appropriate industry standard document. In all cases, the selected document is used in its entirety.

184. ***Detection of Aging Effects:*** In this program, aging effects are detected through water testing and periodic inspections. Water testing ensures that the water treatment program is effective in maintaining acceptable water chemistry. Water testing is conducted in accordance with the selected industry standard. The frequency of water testing is in accordance with the selected industry standard, but in no case should the testing frequency be greater than quarterly. Because the control of water chemistry may not be fully effective in mitigating the aging effects, visual inspections are conducted. Inspections are conducted whenever the system boundary is opened. Additionally, a representative sample of piping and components is selected based on likelihood of corrosion or cracking and inspected at an interval not to exceed once in 10 years. Visual inspections may be conducted in accordance with the selected industry standard document or may be in accordance with ASME standard VT-1. If visual examination identifies adverse conditions, additional examinations, including UT, are conducted. Plant operating experience and/or the industry standard program selected for use in association with this AMP may recommend corrosion testing and/or microbiological testing. If warranted, these tests are conducted in accordance with the industry standard selected or other industry standards appropriate for the conduct of corrosion or microbiological testing.

185. ***Monitoring and Trending:*** Water chemistry data are evaluated against the standards contained in the selected industry standard documents. These data are trended with time so corrective actions are taken, based on trends in water chemistry, before permanent damage is done to the system. Inspection results also are trended with time so the progression of any corrosion or cracking can be evaluated and predicted.

186. ***Acceptance Criteria:*** Water chemistry concentrations are maintained within the limits specified in the selected industry standard document. System components should meet system design requirements, such as minimum wall thickness.

187. ***Corrective Actions:*** Water chemistry concentrations that are not in accordance with the selected industry standard document should be rapidly returned to an "in specification" condition. Some industry standard documents have time guidelines which govern how rapidly "out of specification" conditions should be corrected. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50 Appendix B, acceptable to address corrective actions.

188. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

189. ***Administrative Controls:*** As discussed in the Generic Aging Lessons Learned (GALL) Report, the staff finds the requirements 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

190. ***Operating Experience:*** Degradation of closed-cycle cooling water systems due to corrosion product buildup (NRC Licensee Event Report [LER] 50-327/93-029-00) or through-wall cracks in supply lines (NRC LER 50-280/91-019-00) has been observed in operating plants. Accordingly, operating experience demonstrates the need for this program.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

EPRI TR-1007820, *Closed Cooling Water Chemistry Guideline*, Electric Power Research Institute, Palo Alto, CA, April 2004.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Licensee Event Report 50-280/91-019-00, *Loss of Containment Integrity due to Crack in Component Cooling Water Piping*, October 26, 1991.

NRC Licensee Event Report 50-327/93-029-00, *Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components*, December 13, 1993.

XI.M22 BOR AFLEX MONITORING

Program Description

For Boraflex panels in spent fuel storage racks, gamma irradiation and long-term exposure to the wet fuel pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets. A monitoring program for the Boraflex panels in the spent fuel storage racks is implemented to assure that no unexpected degradation of the Boraflex material compromises the criticality analysis in support of the design of spent fuel storage racks. This aging management program (AMP) relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5 percent subcriticality margin is maintained. Therefore, this AMP includes: (a) completing sampling and analysis for silica levels in the spent fuel pool water on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition), and trending the results by using the EPRI RACKLIFE predictive code or its equivalent; and (b) performing neutron attenuation testing to determine gap formation in Boraflex panels or measuring boron areal density by techniques such as the BADGER device.

Evaluation and Technical Basis

191. ***Scope of Program****:* This AMP manages the effect of reduction in neutron-absorbing capacity due to degradation in sheets of neutron-absorbing material made of Boraflex affixed to spent fuel racks.

192. ***Preventive Actions:*** This is a performance monitoring program. The program includes no preventive actions.

193. ***Parameters Monitored/Inspected:*** The parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25 percent silica, 25 percent polydimethyl siloxane polymer, and 50 percent boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.

194. ***Detection of Aging Effects:*** Aging effects on Boraflex panels are detected by monitoring silica levels in the spent fuel storage pool on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition); by performing blackness testing to measure gap formation or measuring boron areal density on a frequency determined by the material condition of the Boraflex panels, with a maximum of 5 years; and by applying predictive methods to the measured results. The amount of boron carbide present in the Boraflex panel is determined through direct measurement of boron areal density by blackness testing or by periodic verification of boron loss through areal density measurement techniques such as the BADGER device. Frequency of Boraflex testing is sufficient to ensure that Boraflex panel degradation does not compromise criticality analysis for the spent fuel pool storage racks. Additionally, changes in the level of silica present in the spent fuel pool water provide an indication of changes in the rate of degradation of Boraflex panels.

195. ***Monitoring and Trending:*** The periodic inspection measurements and analysis are compared to values of previous measurements and analysis providing a continuing level of data for trend analysis. Sampling and analysis for silica levels in the spent fuel pool water is performed on a regular basis, such as monthly, quarterly, or annually (depending on Boraflex panel condition), and results are trended using the EPRI RACKLIFE predictive code or its equivalent.

196. ***Acceptance Criteria:*** The 5 percent subcriticality margin of the spent fuel racks is maintained for the period of extended operation.

197. ***Corrective Actions:*** Corrective actions are initiated if the test results find that the 5 percent subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts or other options which are available to maintain a subcriticality margin of 5 percent. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

198. ***Confirmation Process:*** Site quality assurance procedures, site review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

199. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

200. ***Operating Experience:*** NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 inches, with the largest 4 inches) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC IN 93-70, NRC IN 95-38, and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. Two spent fuel rack cells with about 12 years of service have only 40 percent of the Boraflex remaining. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets maintain their integrity and are effective in performing their intended function.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

BNL-NUREG-25582, *Corrosion Considerations in the Use of Boral in Spent Fuel Storage Pool Racks*, January 1979.

EPRI NP-6159, *An Assessment of Boraflex Performance in Spent-Nuclear-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 14, 1988.

EPRI TR-1003413, *Guidance and Recommended Procedure for Maintaining and Using RACKLIFE Version 1.10*, Electric Power Research Institute, Palo Alto, CA, April 2002.

EPRI TR-101986, *Boraflex Test Results and Evaluation*, Electric Power Research Institute, Palo Alto, CA, March 1, 1993.

EPRI TR-103300, *Guidelines for Boraflex Use in Spent-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 1, 1993.

NRC Generic Letter 96-04, *Boraflex Degradation in Spent Fuel Pool Storage Racks*, U.S. Nuclear Regulatory Commission, June 26, 1996.

NRC Information Notice 87-43, *Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks,* U.S. Nuclear Regulatory Commission, September 8, 1987.

NRC Information Notice 93-70, *Degradation of Boraflex Neutron Absorber Coupons*, U.S. Nuclear Regulatory Commission, September 10, 1993.

NRC Information Notice 95-38, *Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1995.

NRC Regulatory Guide 1.26, Rev. 3, *Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment),* U.S. Nuclear Regulatory Commission, February 1976.

XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

Most commercial nuclear facilities have between 50 and 100 cranes. Many are industrial grade cranes, which meet the requirements of 29 CFR Volume XVII, Part 1910, and Section 1910.179. Most are not within the scope of 10 CFR 54.4 and therefore are not required to be part of the integrated plant assessment. Because only a few cranes operate over safety-related equipment, normally fewer than 10 cranes fall within the scope of 10 CFR 54.4.

Many of the systems and components of these cranes perform an intended function with moving parts or with a change in configuration or are subject to replacement based on qualified life. In these instances, these types of crane systems and components are not within the scope of this aging management program. This program is primarily concerned with structural components that make up the bridge and trolley. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," provides specific guidance on the control of overhead heavy load cranes. The aging management activities specified in this program utilize the guidance provided in American Society of Mechanical Engineers (ASME) Safety Standard B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)."

Evaluation and Technical Basis

201. ***Scope of Program:*** The program manages (a) the effects of loss of material due to general corrosion on the bridge and trolley structural components for those cranes that are within the scope of 10 CFR 54.4 and (b) the effects of wear on the rails in the rail system. The program also manages the effects of loss of preload of bolted connections.

202. ***Preventive Actions:*** No preventive actions are identified. The crane program is a condition monitoring program.

203. ***Parameters Monitored/Inspected:*** Surface condition is monitored by visual inspection to ensure that loss of material is not occurring due to corrosion or wear. Bolted connections are monitored for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload.

204. **Detection of Aging Effect:** Crane rails and structural components are visually inspected at a frequency in accordance ASME B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)," or other appropriate standard in the ASME B30 series. For systems that are infrequently in service, such as containment polar cranes, periodic inspections are performed once every refueling cycle just prior to use. Bolted connections are visually inspected for loss bolts or missing nuts at the same frequency as crane rails and structural components.

205. ***Monitoring and Trending:*** Visual inspection activities are performed by associated personnel qualified in accordance with controlled procedures and processes. Deficiencies are documented using approved processes and procedures such that results can be trended; however, the program does not include formal trending.

206. ***Acceptance Criteria:*** Any visual indication of loss of material due to corrosion or wear and any visual sign of loss of bolting pre-load is evaluated according to ASME B30.2 or other applicable industry standard in the ASME B30 series.

207. ***Corrective Actions:*** Repairs are performed as specified in ASME B30.2 or other appropriate standard in the ASME B30 series. Site corrective action programs, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

208. ***Confirmation Process:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

209. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

210. Operating Experience: There has been no history of corrosion-related degradation that threatened the ability of a crane to perform its intended function. Likewise, because cranes have not been operated beyond their design lifetime, there have been no significant fatigue-related structural failures.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 54.4, *Scope*, Office of the Federal Register, National Archives and Records Administration, 2009.

ASME Safety Standard B30.2, Overhead and Gantry Cranes *(Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist),* American Society of Mechanical Engineers, 2005.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, March 1997.

NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, U.S. Nuclear Regulatory Commission, 1980.

XI.M24 COMPRESSED AIR MONITORING

Program Description

The purpose of the compressed air monitoring program is to ensure the integrity of the compressed air system. The program consists of moisture content and corrosion monitoring, and performance monitoring of the compressed air system. This includes (a) frequent leak testing of valves, piping, and other system components; (b) preventive monitoring to ensure that water is kept within the specified limits; and (c) inspection of components for indications of loss of material due to corrosion.

The compressed air monitoring aging management program (AMP) is based on results of the plant owner's response to Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14 (applicable to license renewal) and reported in previous NRC Information Notices (IN) 81-38; IN 87-28; IN 87-28, Supplement 1; and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01. NRC GL 88-14, issued after several years of study of problems and failures of instrument air systems, recommends each holder of an operating license perform an extensive design and operations review and verification of its instrument air system. GL 88-14 also recommends the licensees describe their program for maintaining proper instrument air quality. This AMP does not include all aspects of GL 88-14 because many of the issues in the GL are not relevant for license renewal considerations.

This AMP does not change the applicant's commitments relative to GL 88-14 for the rest of their operations. The program utilizes the aging management aspects of the applicant's response to GL 88-14 for license renewal with regard to preventative measures, inspections of components, and testing to ensure the compressed air system will be able to perform its intended function in the period of extended operation. The AMP also incorporates the air quality provisions provided in the guidance of the Electric Power Research Institute (EPRI) NP-7079. NP-7079 was issued in 1990 to assist utilities in identifying and correcting system problems in the instrument air system and to enable them to maintain required industry safety standards. Subsequent to these initial actions by all plant licensees to implement an improved AMP, some utilities decided to replace their instrument air system with newer models and types of components. The EPRI then issued TR-108147, which addresses maintenance of the latest compressors and other instrument air system components currently in use at those plants. The American Society of Mechanical Engineers (ASME) operations and maintenance standards and guides (ASME OM-S/G-1998, Part 17) provides additional guidance to the maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

Evaluation and Technical Basis

211. ***Scope of Program:*** The program manages aging effects of loss of material due to corrosion in compressed air systems that are exposed to an environment of dried air.

212. ***Preventive Actions:*** For the purposes of aging management, moisture and other corrosive contaminants in the system's air are maintained below specified limits to ensure that the system and components maintain their intended functions. These requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME OM-S/G-1998, Part 17; American National Standards Institute (ANSI)/ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147.

213. ***Parameters Monitored/Inspected:*** Maintaining air quality below acceptable limits ensures that loss of material due to corrosion is prevented or mitigated. Periodic air samples are taken and analyzed for moisture and other corrosives. Inspections of all accessible internal surfaces are performed for signs of corrosion, erosion, and abnormal corrosion products that might indicate a loss of material within the system. Pressure decay leak testing is performed periodically to ensure the integrity of the pressure boundary. Performance monitoring, such as compressor cycle time, provides an indication of system integrity.

214. ***Detection of Aging Effects:*** Moisture and other corrosives increase the potential for the loss of material due to corrosion. The program calls for the periodic sampling and testing of air quality in the compressed system for moisture in accordance with industry standards, such as ASI –S7.0.01. Typically, compressed systems have in-line dew point instrumentation that is checked daily to ensure moisture content is within specifications. Additionally, periodic visual inspections of critical component internal surfaces (compressors, dryers, after-coolers, and filters) are performed for signs of loss of material due to corrosion. ASME O/M-S/G, Part 17 (1998) provides guidance for inspection frequency and inspection methods of these components. Leaks found during pressure testing are evaluated for potential wall thinning due to loss of material. If corrosives other than moisture are present, appropriate testing should be proposed.

215. ***Monitoring and Trending:*** Daily readings of system dew point are recorded and reviewed for adverse trends. Air quality analysis results are reviewed to determine if alert levels or limits have been reached or exceeded. This review also checks for unusual trends. ASME O/M-S/G, Part 17, also provides guidance for monitoring and trending data. Visual inspection results are compared to previous results to ascertain if adverse long term trends exist. The effects of corrosion are monitored by visual inspection and periodic system and component tests, including leak rate tests on the system and on individual items of components. These tests verify proper operation by comparing measured values of performance with specified performance limits. Test data are analyzed and compared to data from previous tests to provide for the timely detection of aging effects on passive components.

216. ***Acceptance Criteria:*** Acceptance criteria for air quality moisture limits are established based on accepted industry standards, such as ISA-S7.0.01. Internal surfaces should not show signs of loss of material due to the presence of moisture. Manufacturers' certifications can be used to demonstrate that the bottled air meets acceptable quality standards. The pressure decay leak tests verify proper operation by comparing measured values of performance with specific performance limits. Test data are analyzed and compared to data from previous tests to provide for timely detection of aging effects.

217. ***Corrective Actions:*** Corrective actions are taken if any parameters are out of acceptable ranges, such as moisture content in the system air. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

218. ***Confirmation Process:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

219. ***Administrative Controls:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

220. ***Operating Experience:*** Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38; IN 87-28; IN 87-28, Supplement 1; and License Event Report 50-237/94-005-3. Some of the systems that have been significantly degraded or have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal system. In 2008, one plant incurred an unplanned reactor trip from a failure of a mechanical joint in the instrument air system (IN 2008-06). Nevertheless, as a result of NRC GL 88-14 and in consideration of INPO SOER 88-01, EPRI NP-7079, and EPRI TR-108147, performance of air systems has improved significantly.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ANSI/ISA-S7.0.01-1996, *Quality Standard for Instrument Air*, American National Standards Institute (ANSI), 1996.

ASME OM-S/G-1998, Part 17, *Performance Testing of Instrument Air Systems Information Notice Light-Water Reactor Power Plants*, 1ISA-S7.0.1-1996, “Quality Standard for Instrument Air,” American Society of Mechanical Engineers, New York, NY, 1998.

EPRI NP-7079, *Instrument Air System: A Guide for Power Plant Maintenance Personnel*, Electric Power Research Institute, Palo Alto, CA, December 1990.

EPRI/NMAC TR-108147, *Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079*, Electric Power Research Institute, Nuclear Maintenance Application Center, Palo Alto, CA, March 1998.

INPO Significant Operating Experience Report 88-01, *Instrument Air System Failures*, Institute of Nuclear Power Operations, May 18, 1988.

NRC Generic Letter 88-14, *Instrument Air Supply Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, August 8, 1988.

NRC Information Notice 81-38, *Potentially Significant Components Failures Resulting from Contamination of Air-Operated Systems*, U.S. Nuclear Regulatory Commission, December 17, 1981.

NRC Information Notice 87-28, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, June 22, 1987.

NRC Information Notice 87-28, Supplement 1, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, December 28, 1987.

NRC Information Notice 2008-06, *Instrument Air System Failure Resulting In Manual Reactor Trip*, U.S. Nuclear Regulatory Commission, April 10, 2008.

NRC Licensee Event Report 50-237/94-005-3, *Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction*, U.S. Nuclear Regulatory Commission, April 23, 1997.

XI.M25 BWR REACTOR WATER CLEANUP SYSTEM

Program Description

This program provides inservice inspection (ISI) to manage the aging effects of cracking due to stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of austenitic stainless steel (SS) piping outboard of the second primary containment isolation valves in the reactor water cleanup (RWCU) system. Based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and in NRC Generic Letter (GL) 88-01 and its Supplement 1. The aging management review (AMR) line item in the Generic Aging Lessons Learned (GALL) Report that credits this program also credits AMP XI.M2, “Water Chemistry,” to provide mitigation of the aging effects.

NRC GL 88-01 applies to all boiling water reactor (BWR) piping made of austenitic SS that is 4 inches or larger in nominal diameter and contains reactor coolant at a temperature above 93.3 degrees Celsius (200 degrees Fahrenheit) during power operation regardless of code classification. NRC GL 88-01 requests, in part, that affected licensees implement an ISI program conforming to staff positions for austenitic SS piping covered under the scope of the letter. In response to NRC GL 88-01, affected licensees committed to perform ISI in accordance with the scope and schedules described in the letter and the commitments included affected portions of RWCU piping outboard of the second isolation valves.

The NRC issued GL 88-01, Supplement 1, to provide acceptable alternatives to staff positions delineated in NRC GL 88-01. In NRC GL 88-01, Supplement 1, the staff noted, in part, that the position stated in NRC GL 88-01 on inspection sample size of RWCU system welds outboard of the second isolation valves had created an unnecessary hardship for affected licensees because of the very high radiation levels associated with this portion of RWCU piping. The staff also noted that affected licensees had requested that they be exempted from NRC GL 88-01 with regard to inspection of this piping of the RWCU system. The staff determined, however, that the service-sensitive RWCU system piping is subject to the most aggressive environment with regard to IGSCC and that until the actions associated with NRC GL 89-10 on motor-operated valves are completed by a licensee, an inspection of the subject RWCU piping on a sampling basis of at least 10 percent of the affected weld population should be performed during each refueling outage to ensure the integrity of the piping.

Although NRC GL 88-01, Supplement 1, does not provide explicit generic guidance with regard to staff criteria for reduction or elimination of previously committed RWCU weld inspections, it does suggest that the staff would be receptive to reduction or elimination of a licensee’s original NRC GL 88-01 commitment for RWCU weld inspections, provided all issues with reactor safety were adequately addressed. The staff has subsequently allowed individual licensees to reduce or eliminate their NRC GL 88-01 commitments for ISI of RWCU welds in the piping outboard of the second isolation valves.

Evaluation and Technical Basis

221. ***Scope of Program:*** This program provides ISI to manage the aging effects of cracking due to SCC or IGSCC in austenitic SS piping outboard of the second primary containment isolation valves in the RWCU system. The components included in this program are the welds in piping that has a nominal diameter 4 inches or larger and that contains reactor coolant at a temperature above 200 degrees Fahrenheit during power operation, regardless of code classification.

222. ***Preventive Actions:*** The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG-0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 weight percent and a minimum ferrite of 7.5 weight percent in weld metal and cast austenitic stainless steel. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

The program delineated in NUREG-0313 and NRC GL 88-01 varies depending on the plant-specific reactor water chemistry to mitigate SCC or IGSCC.

223. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detecting and sizing cracks in accordance with the requirements of American Society of Mechanical Engineers (ASME) Code, Section XI; the guidelines of NUREG-0313, NRC GL 88-01, and NRC GL 88-01, Supplement 1; and the NRC screening criteria for the RWCU piping outboard of the second isolation valves.

224. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and testing techniques delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, sample expansion, and leak detection guidelines are based on the guidelines of NRC GL 88-01 and GL 88-01, Supplement 1, and subsequent licensing correspondence. Consistent with the NRC guidelines and with licensees' completion of all actions requested in NRC GL 89-10, no inspection of the outboard piping is required for (a) piping systems that are made of IGSCC-resistant piping materials or (b) piping with no IGSCC detected inboard of the second isolation valves (ongoing GL 88-01 inspection) and outboard of the second isolation valves (after inspecting a minimum of 10 percent of susceptible piping welds). For piping that includes a non-resistant base or weld material in the scope of the program or piping that has experienced IGSCC, either inboard or outboard of the second isolation valves, an inspection of at least 2 percent of the welds or two welds, whichever is greater, is performed on the portions of the RWCU system outboard of the second isolation valves every refueling outage.

225. ***Monitoring and Trending:*** The extent and schedule for inspection in accordance with the recommendations of NRC GL 88-01 provide timely detection of cracks and leakage of coolant. Based on inspection results, NRC GL 88-01 provides guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.

226. ***Acceptance Criteria:*** NRC GL 88-01 recommends that any indication detected be evaluated in accordance with the requirements of ASME Code, Section XI, Subsection IWB-3640.

227. *Corrective Actions*: The guidance for weld overlay repair, stress improvement, or replacement is provided in NRC GL 88-01. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

228. *Confirmation Process:* Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

229. *Administrative Controls:* As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

230. *Operating Experience:* The IGSCC has occurred in small- and large-diameter BWR piping made of austenitic SS. The comprehensive program outlined in NRC GL 88-01 and NUREG-0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition[1] (no addenda), American Society of Mechanical Engineers, New York, NY.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,* U.S. Nuclear Regulatory Commission, January 25, 1988.

NRC Generic Letter 88-01, Supplement 1, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,* U.S. Nuclear Regulatory Commission, February 4, 1992.

NRC Generic Letter 89-10, *Safety-related Motor Operated Valve Testing and Surveillance,* U.S. Nuclear Regulatory Commission, June 28, 1989; through Supplement 7, January 24, 1996.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping,* W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

Letter from Joseph W. Shea, U.S. Nuclear Regulatory Commission, to George A. Hunger, Jr., PECO Energy Company, *Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station*, *Units 2 and 3 (TAC Nos. M92442 and M92443)*, September 15, 1995. (ADAMS Accession Number ML090930466)

[1] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code Section XI.

Letter from Robert M. Pulsifer, U.S. Nuclear Regulatory Commission, to Michael A Balduzzi, Vermont Yankee Nuclear Power Corporation, *Review of Request to Discontinue Intergranular Stress Corrosion Cracking Inspection of RWCU Piping Welds Outboard of the Second Containment Isolation Valves (TAC No. MB0468),* March 27, 2001. (ADAMS Accession Number ML010780094)

XI.M26 FIRE PROTECTION

Program Description

For operating plants, the Fire Protection aging management program (AMP) includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals; fire barrier walls, ceilings, and floors; and periodic visual inspection and functional tests of fire-rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection program requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The AMP also includes periodic inspection and testing of the halon/carbon dioxide (CO_2) fire suppression system.

Evaluation and Technical Basis

231. ***Scope of Program:*** For operating plants, the AMP manages the aging effects on the intended function of the penetration seals; fire barrier walls, ceilings, and floors; other materials (e.g., flamastic, 3M fire wrapping, spray-on fire proofing material, intumescent coating, etc.) that serve a fire barrier function; and all fire-rated doors (automatic or manual) that perform a fire barrier function. It also manages the aging effects on the intended function of the fuel supply line. The AMP also includes management of the aging effects on the intended function of the halon/CO_2 fire suppression system.

232. ***Preventive Actions:*** For operating plants, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing structures, systems, and components important to safety.

233. ***Parameters Monitored/Inspected:*** Visual inspection of not less than 10 percent of each type of penetration seal is performed during walkdowns. These inspections examine any sign of degradation such as cracking; seal separation from walls and components; separation of layers of material; rupture and puncture of seals, which are directly caused by increased hardness; and shrinkage of seal material due to weathering. Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Visual inspection of other fire barrier materials examines any signs of degradation. Fire-rated doors are visually inspected to verify the integrity of door surfaces and for clearances.

The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detection of any degradation of the fuel supply line. Visual inspection of the fuel oil supply line is performed during the performance test to detect for any sign of degradation.

The periodic visual inspection and function test is performed to examine the signs of degradation of the halon/CO_2 fire suppression system. Material conditions that may affect the performance of the system, such as corrosion or mechanical damage/damage to dampers (which could be a precursor to corrosion), are observed during these tests.

234. ***Detection of Aging Effects:*** Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture of seals. Visual inspection by fire protection qualified inspectors of not less than 10 percent of each type of seal in walkdowns is performed at least once every refueling cycle. If any sign of degradation is detected within that sample, the scope of the inspection is expanded to include additional seals. Visual inspection by fire protection qualified inspectors of the fire barrier walls, ceilings, and floors performed in walkdowns at least once every refueling outage ensures timely detection of concrete cracking, spalling, and loss of material. Visual inspection of other fire barrier materials is performed at least once every refueling outage to detect any signs of degradation. Visual inspection by fire protection qualified inspectors detects any sign of degradation of the fire door, such as wear and missing parts. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.

Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pumps, ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before the loss of the component intended function.

Visual inspections of the halon/CO_2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers (which could be a precursor to corrosion). The periodic function test is performed at least once every 6 months or on a schedule from the current licensing basis, and inspections are performed every 6 months to detect degradation of the halon/CO_2 fire suppression system before the loss of the component intended function.

235. ***Monitoring and Trending:*** The aging effects of weathering on fire barrier penetration seals are detectable by visual inspection. Results of inspections are used to trend future actions.

Concrete cracking, spalling, and loss of material are detectable by visual inspection. Degraded integrity or clearances in the fire door are detectable by visual inspection. Results of inspections are used to trend future actions.

The performance of the fire pump is monitored during the periodic test to detect any degradation in the fuel supply lines. Periodic testing provides data (e.g., pressure) necessary for trending.

The performance of the halon/CO_2 fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

236. ***Acceptance Criteria:*** Inspection results are acceptable if there are (a) no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals; (b) no visual indications of concrete cracking, spalling, and loss of material of fire barrier walls, ceilings, and floors; (c) no sign of degradation in other fire barrier materials; (d) no visual indications of missing parts, holes, and wear; and (e) no deficiencies in the functional tests of fire doors. No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump. Also, any signs of corrosion in the halon/CO_2 fire suppression system are not acceptable.

237. ***Corrective Actions:*** For fire protection structures and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. This commitment is documented in the final safety analysis report supplement in accordance with 10 CFR 54.21(d). As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

238. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

239. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

240. ***Operating Experience:*** Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes (U.S. Nuclear Regulatory Commission [NRC] Information Notice [IN] 88-56, IN 94-28, and IN 97-70). Degradation of electrical raceway fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (NRC IN 91-47 and NRC Generic Letter 92-08). Fire doors have experienced wear of the hinges and handles.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 92-08, *Thermo-Lag 330-1 Fire Barrier*, U.S. Nuclear Regulatory Commission, December 17, 1992.

NRC Information Notice 88-56, *Potential Problems with Silicone Foam Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, August 14, 1988.

NRC Information Notice 91-47, *Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test*, U.S. Nuclear Regulatory Commission, August 6, 1991.

NRC Information Notice 94-28, *Potential Problems with Fire-Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, April 5, 1994.

NRC Information Notice 97-70, *Potential Problems with Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, September 19, 1997.

XI.M27 FIRE WATER SYSTEM

Program Description

This aging management program (AMP) applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated.

A sample of sprinkler heads is tested by using the guidance of NFPA 25, "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1, or NFPA 25 (2002 Edition), Section 5.3.1.1.1. These NFPA sections state "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing.

The fire protection system piping is subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness (e.g., non-intrusive volumetric testing or plant maintenance visual inspections) to ensure that aging effects are managed and that wall thickness is within acceptable limits. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. The plant-specific inspection intervals are determined by engineering evaluation of the fire protection piping to ensure that degradation is detected before the loss of intended function. The purpose of the full flow testing and wall thickness evaluations is to ensure that corrosion, microbiologically influenced corrosion (MIC), or biofouling is managed such that the system function is maintained.

Evaluation and Technical Basis

241. ***Scope of Program:*** The AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of steel components in fire protection systems exposed to water. Hose stations and standpipes are considered as piping in the AMP. Hoses and gaskets can be excluded from the scope of license renewal if the standards that are relied upon to prescribe replacement of the hose and gaskets are identified in the scoping methodology description.

242. ***Preventive Actions:*** To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing and system performance testing may be conducted.

243. ***Parameters Monitored/Inspected:*** Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Periodic flow testing of the fire water system is performed using the guidelines of NFPA 25, or wall thickness evaluations may be performed to ensure that the system maintains its intended function. Testing of sprinklers ensures degradation is detected in timely manner.

244. ***Detection of Aging Effects:*** Fire protection system testing is performed to ensure that the system functions by maintaining required operating pressures. Wall thickness evaluations of fire protection piping are performed on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation.

As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis. These inspections are capable of evaluating (a) wall thickness to ensure against catastrophic failure and (b) the inner diameter of the piping as it applies to the design flow of the fire protection system.

If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of below grade fire protection piping. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping is maintained consistent with the current licensing basis for the period of extended operation.

Continuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and the system's intended function is maintained.

General requirements of existing fire protection programs include testing and maintenance of fire detection and protection systems and surveillance procedures to ensure that fire detectors as well as fire protection systems and components are operable.

Visual inspection of yard fire hydrants performed annually in accordance with NFPA 25 ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities to detect degradation before a loss of intended function can occur.

Sprinkler heads are tested before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

245. ***Monitoring and Trending:*** System discharge pressure is monitored continuously. Results of system performance testing are monitored and trended as specified by the associated plant commitments pertaining to NFPA codes and standards. Degradation identified by non-intrusive or visual inspection is evaluated.

246. ***Acceptance Criteria:*** The acceptance criteria are (a) the fire protection system is able to maintain required pressure, (b) no unacceptable signs of degradation are observed during non-intrusive or visual inspection of components, (c) minimum design wall thickness is maintained and (d) no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.

247. ***Corrective Actions:*** Repair and replacement actions are initiated as necessary. For fire water systems and components identified within scope that are subject to an aging management review (AMR) for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions for aging management during the period of extended operation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

248. ***Confirmation Process:*** For fire water systems and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for confirmation process for aging management during the period of extended operation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

249. ***Administrative Controls:*** For fire water systems and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for administrative controls for aging management during the period of extended operation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

250. ***Operating Experience:*** Water-based fire protection systems designed, inspected, tested, and maintained in accordance with the NFPA minimum standards have demonstrated reliable performance.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NFPA 25, *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*, 1998 Edition, National Fire Protection Association.

NFPA 25, *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*, 2002 Edition, National Fire Protection Association.

NFPA 25, *Inspection, Testing and Maintenance of Water-Based Fire Protection Systems*, 2008 Edition, National Fire Protection Association.

XI.M29 ABOVEGROUND METALLIC TANKS

Program Description

The Aboveground Metallic Tanks aging management program (AMP) manages the effects of loss of material on the outer surfaces of above ground tanks constructed on concrete or soil. If the tank exterior is fully visible, the program for inspection of external surfaces may be used instead (XI.M36). This program credits the standard industry practice of coating or painting the external of steel tanks as a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor degradation of the protective paint or coating. However, for storage tanks supported on earthen or concrete foundations, corrosion may occur at inaccessible locations, such as the tank bottom. Accordingly, verification of the effectiveness of the program is performed to ensure that significant degradation in inaccessible locations is not occurring and the component intended function is maintained during the extended period of operation. For reasons set forth below, an acceptable verification program consists of thickness measurement of the tank bottom surface.

Evaluation and Technical Basis

251. ***Scope of Program****:* The program consists of periodic inspections of metallic tanks (with or without coatings) to manage the effects of corrosion on the intended function of these tanks. Inspections cover the entire outer surface of the tank. Because lower portions of the tank are on concrete or soil, this program includes the bottom of the tank as well. If the tank exterior is fully visible, the program for inspection of external surfaces may be used instead (XI.M36).

252. ***Preventive Actions:*** In accordance with industry practice, tanks may be coated with protective paint or coating to mitigate corrosion by protecting the external surface of the tank from environmental exposure. Sealant or caulking may be applied at the external interface between the tank and concrete or earthen foundation to mitigate corrosion of the bottom surface of the tank by minimizing the amount of water and moisture penetrating the interface, which would lead to corrosion of the bottom surface.

253. ***Parameters Monitored/Inspected:*** The AMP utilizes periodic plant inspections to monitor degradation of coatings, sealants, and caulking because it is a condition directly related to the potential loss of materials. Additionally, thickness measurements of the bottom of the tanks are made periodically for the tanks monitored by this program as an additional measurement to ensure loss of material is not occurring at locations that are inaccessible for inspection.

254. ***Detection of Aging Effects:*** Degradation of exterior metallic surface can occur in the presence of moisture; therefore, an inspection of the coating is performed to ensure that the surface is protected from moisture. Conducting periodic visual inspections (VT-3) at each outage to confirm that the paint, coating, sealant, and caulking are intact is an effective method to manage the effects of corrosion on the external surface of the component. Potential corrosion of tank bottoms is determined by taking ultrasonic testing (UT) thickness measurements of the tank bottoms whenever the tank is drained and at least once within 5 years of entering the period of extended operation. Measurements are taken to ensure that significant degradation is not occurring and the component intended function is maintained during the extended period of operation.

255. ***Monitoring and Trending:*** The effects of corrosion of the aboveground external surface are detectable by visual techniques. Based on operating experience, plant inspections during each outage provide for timely detection of aging effects. The effects of corrosion of the underground external surface are detectable by UT thickness measurement of the tank bottom and are monitored and trended if significant material loss is detected where multiple measurements are available.

256. ***Acceptance Criteria:*** Any degradation of paints or coatings (cracking, flaking, or peeling) is reported and requires further evaluation. Drying, cracking, or missing sealant and caulking are unacceptable and need to be repaired. UT thickness measurements of the tank bottom are evaluated against the design thickness and corrosion allowance.

257. ***Corrective Actions:*** The site corrective actions program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls. Flaws in the caulking or sealant are repaired.

258. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

259. ***Administrative Controls:*** As discussed in the appendix to the GALL Report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

260. ***Operating Experience:*** Coating degradation, such as flaking and peeling, has occurred in safety-related systems and structures (U.S. Nuclear Regulatory Commission [NRC] Generic Letter 98-04). Corrosion damage near the concrete-metal interface and sand-metal interface has been reported in metal containments (NRC Information Notice [IN] 89-79, Supplement 1, and NRC IN 86-99, Supplement 1).

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 98-04, *Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment*, U.S. Nuclear Regulatory Commission, July 14, 1998.

NRC Information Notice 86-99, *Degradation of Steel Containments*, U.S. Nuclear Regulatory Commission, December 8, 1986.

NRC Information Notice 86-99, Supplement 1, *Degradation of Steel Containments*, U.S. Nuclear Regulatory Commission, February 14, 1991.

NRC Information Notice 89-79, *Degraded Coatings and Corrosion of Steel Containment Vessel*, U.S. Nuclear Regulatory Commission, December 1, 1989.

NRC Information Notice 89-79, Supplement 1, *Degraded Coatings and Corrosion of Steel Containment Vessel*, U.S. Nuclear Regulatory Commission, June 29, 1990.

XI.M30 FUEL OIL CHEMISTRY

Program Description

The program includes (a) surveillance and maintenance procedures to mitigate corrosion and (b) measures to verify the effectiveness of the mitigative actions and confirm the insignificance of an aging effect. Fuel oil quality is maintained by monitoring and controlling fuel oil contamination in accordance with the plant's technical specifications. Guidelines of the American Society for Testing Materials (ASTM) Standards, such as ASTM D 0975-04, D 1796-97, D 2276-00, D 2709-96, D 6217-98, and D 4057-95, may also be used. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by periodic draining or cleaning of tanks and by verifying the quality of new oil before its introduction into the storage tanks. However, corrosion may occur at locations in which contaminants may accumulate, such as tank bottoms. Accordingly, the effectiveness of the program is verified to ensure that significant degradation is not occurring and the component's intended function is maintained during the extended period of operation. Thickness measurement of tank bottom surfaces is an acceptable verification program.

Evaluation and Technical Basis

261. ***Scope of Program:*** Components within the scope of the program are the diesel fuel oil storage tanks, piping, and other metal components subject to aging management review that are exposed to an environment of diesel fuel oil. The program is focused on managing loss of material due to general, pitting, and microbiologically-influenced corrosion (MIC) of the diesel fuel tank internal surfaces.

262. ***Preventive Actions:*** The program reduces the potential for (a) exposure of the storage tanks' internal surface to fuel oil contaminated with water and microbiological organisms, reducing the potential for age-related degradation in other components exposed to diesel fuel oil; and (2) transport of corrosion products, sludge, or particulates to components serviced by the fuel oil storage tanks. Biocides or corrosion inhibitors are added as a preventive measure or if periodic testing indicates biological activity or evidence of corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

263. ***Parameters Monitored/Inspected:*** The program is focused on managing loss of material due to general, pitting, and MIC of the diesel fuel tank internal surfaces. The aging management program monitors fuel oil quality through receipt testing and periodic sampling of stored fuel oil. Parameters monitored include water and sediment content, total particulate concentration, and the levels of microbiological organisms in the fuel oil. Water and microbiological organisms in the fuel oil storage tank increase the potential for corrosion. Sediment and total particulate content may be indicative of water intrusion or corrosion.

264. ***Detection of Aging Effects:*** Loss of material due to corrosion of the diesel fuel oil tank or other components exposed to diesel fuel oil cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring. Each diesel fuel oil storage tank should be cleaned and inspected at least once during the 10-year period prior to the period of extended operation.

Prior to the period of extended operation, a one-time inspection of selected components exposed to diesel fuel oil is performed to verify the effectiveness of the Fuel Oil Chemistry program.

265. ***Monitoring and Trending:*** Water, biological activity, and particulate contamination concentrations are monitored and trended at least quarterly. Based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function.

266. ***Acceptance Criteria:*** Acceptance criteria for fuel oil quality parameters are as invoked or referenced in a plant's technical specifications. Additional acceptance criteria may be implemented using guidance from industry standards and equipment manufacturer or fuel oil supplier recommendations. ASTM D 0975-04 or other appropriate standards may be used to develop fuel oil quality acceptance criteria. Suspended water concentrations are in accordance with the applicable fuel oil quality specifications. Corrective actions are taken if microbiological activity is detected.

267. ***Corrective Actions:*** Specific corrective actions are implemented in accordance with the plant quality assurance (QA) program. For example, corrective actions are taken to prevent recurrence when the specified limits for fuel oil standards are exceeded or when water is drained during periodic surveillance. If accumulated water is found in a fuel oil storage tank, it is immediately or promptly removed. Also, when the presence of biological activity is confirmed, a biocide is added to fuel oil. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

268. ***Confirmation Process:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

269. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's quality assurance (QA) program in accordance with the requirements of 10 CFR Part 50, Appendix B.

270. ***Operating Experience:*** The operating experience at some plants has included identification of water in the fuel, particulate contamination, and biological fouling. In addition, when a diesel fuel oil storage tank at one plant was cleaned and visually inspected, the inside of the tank was found to have unacceptable pitting corrosion (greater than 50 percent of the wall thickness), which was repaired in accordance with American Petroleum Institute (API) 653 standard by welding patch plates over the affected area.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

API 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, American Petroleum Institute, April 23, 2009.

ASTM D 0975-04, *Standard Specification for Diesel Fuel Oils*, American Society for Testing Materials, West Conshohocken, PA, 2004.

ASTM D 1796-97,*Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method*, American Society for Testing Materials, West Conshohocken, PA, 1997.

ASTM D 2276-00,*Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling,* American Society for Testing Materials, West Conshohocken, PA, 2000.

ASTM D 2709-96,*Standard Test Method for Water and Sediment in Middle Distillate Fuels by Centrifuge*, American Society for Testing Materials, West Conshohocken, PA, 1996.

ASTM D 4057-95, *Standard Practice for Manual Sampling of Petroleum and Petroleum Products*, American Society for Testing Materials, West Conshohocken, PA, 2000.

ASTM D 6217-98, *Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration*, American Society for Testing Materials, West Conshohocken, PA, 1998.

Safety Evaluation Report Related to the License Renewal of Three Mile Island Nuclear Unit 1, Section 3.0.3.2.12, *Fuel Oil Chemistry – Operating Experience*, June 2009.

XI.M31 REACTOR VESSEL SURVEILLANCE

Program Description

The Code of Federal Regulations, 10 CFR Part 50, Appendix H, requires that peak neutron fluence at the end of the design life of the vessel will not exceed 10^{17} n/cm^2 (E > 1 MeV) or that reactor vessel beltline materials be monitored by a surveillance program to meet the American Society for Testing and Materials (ASTM) E 185 standard. However, the surveillance program in ASTM E 185 is based on plant operation during the current license term, and additional surveillance capsules may be needed for the period of extended operation. Alternatively, an integrated surveillance program for the period of extended operation may be considered for a set of reactors that have similar design and operating features in accordance with 10 CFR Part 50, Appendix H, Paragraph II.C. Additional surveillance capsules may also be needed for the period of extended operation for this alternative.

The existing reactor vessel material surveillance program provides sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux. If surveillance capsules are not withdrawn during the period of extended operation, operating restrictions are to be established to ensure that the plant is operated under the conditions to which the surveillance capsules were exposed.

All capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of the 1982 edition of ASTM E 185 (ASTM E 185-82), to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including spare capsules, must be approved by the Nuclear Regulatory Commission (NRC) prior to implementation. Untested capsules placed in storage must be maintained for future insertion.

Evaluation and Technical Basis

The Reactor Vessel Surveillance program is plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR Part 50, Appendix H, an applicant submits its proposed withdrawal schedule for approval prior to implementation. Thus, further staff evaluation is required for license renewal.

271. **Scope of Program**: The program includes all reactor vessel beltline materials as defined by 10 CFR 50, Appendix G, Section II.F. The program is a condition monitoring program that measures the increase in Charpy V-notch 30 foot-pound (ft-lb) transition temperature and the drop in the upper shelf energy as a function of neutron fluence and irradiation temperature. The data from this surveillance program is used to monitor neutron irradiation embrittlement and is used in the time limited aging analyses that are described in Section 4.2 of the safety evaluation for license renewal. Materials originally monitored within the scope of the licensee’s existing 10 CFR Part 50, Appendix H, materials surveillance program will continue to serve as the basis for the reactor vessel surveillance aging management program unless safety considerations for the term of the renewed license would require the monitoring of additional or alternative materials.

272. ***Preventive Actions:*** The program is a surveillance program; no preventive actions are identified.

273. ***Parameters Monitored/Inspected:*** The program monitors reduction of fracture toughness of reactor vessel beltline materials due to neutron irradiation embrittlement and monitors reactor vessel long term operating conditions (cold leg operating temperature and neutron fluence) that could effect neutron irradiation embrittlement of the reactor vessel. The program uses two parameters to monitor the effects of neutron irradiation: (a) the increase in the Charpy V-notch 30 ft-lb transition temperature and (b) the drop in the Charpy V-notch upper shelf energy. The program uses neutron dosimeters to monitor neutron fluence. Low melting point elements or eutectic alloys may be used to monitor irradiation temperature. Preferably, irradiation temperature will be monitored from cold leg operating temperatures. The Charpy V-notch specimens, neutron dosimeters, and temperature monitors are placed in capsules that are located within the reactor vessel; the capsules are withdrawn periodically to monitor the reduction in fracture toughness due to neutron irradiation.

274. **Detection of Aging Effects:** Reactor vessel beltline materials will be monitored by a surveillance program in which surveillance capsules are withdrawn from the reactor vessel and tested in accordance with ASTM E 185-82. This ASTM standard describes the methods used to monitor irradiation embrittlement (described in Element 3, above), selection of materials, and the withdrawal schedule for capsules. However, the surveillance program in ASTM E 185 is based on plant operation during the current license term, and additional surveillance capsules may be needed for the period of extended operation. Alternatively, an integrated surveillance program for the period of extended operation may be considered for a set of reactors that have similar design and operating features in accordance with 10 CFR Part 50, Appendix H, Paragraph II.C. Additional surveillance capsules may also be needed for the period of extended operation for this alternative.

The plant-specific or integrated surveillance program shall have at least one capsule with a projected neutron fluence exceeding the 60-year peak reactor vessel wall neutron fluence prior to the end of the period of extended operation. The program withdraws one capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation and tests the capsule in accordance with the requirements of ASTM E 185-82. The applicant shall make necessary adjustments to the withdrawal schedule so that meaningful high fluence data can be obtained from the capsules.

The program may retain additional capsules within the reactor vessel to support additional testing if, for example, the data from the required surveillance capsule turn out to be invalid or another license extension is expected. These additional capsules may be managed in a similar way for future use. If the projected neutron fluence for these additional capsules is expected to be excessive if left in the reactor vessel, the program may propose to withdraw and place one or more untested capsules in the storage for future reinsertion and/or testing.

If a plant has ample capsules remaining for future use, all pulled and tested samples or capsules placed in storage with a reactor vessel neutron fluence less than 50 percent of the projected neutron fluence at the end of the period of extended operation may be discarded. Pulled and tested samples, unless discarded before August 31, 2000, and capsules with a neutron fluence greater than 50 percent of the projected reactor vessel neutron fluence at the end of the period of extended operation are placed in storage (These specimens and capsules are saved for future reconstitution and reinsertion use.) unless the applicant has gained NRC approval to discard the pulled and tested samples or capsules.

If an applicant does not have ample capsules remaining for future use, all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage. (These specimens are saved for future reconstitution use, in case the surveillance program is reestablished.)

Plant-specific and fleet operating experience should be considered in determining the withdrawal schedule for all capsules; the withdrawal schedule shall be submitted as part of a license renewal application for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.

If all surveillance capsules have been removed, a licensee may seek membership in an integrated surveillance program unless the integrated surveillance program does not have surveillance material representative of its limiting beltline materials or the program can propose one of the following:

(a) An Active Surveillance Program with Reinstituted Specimens

This program consists of (1) capsules from a surveillance program described above, (2) reconstitution of specimen from tested capsules, (3) capsules made from any available archival materials, or (4) some combination of the three previous options. This program could be a plant-specific program or an integrated surveillance program.

(b) An Alternative Neutron Monitoring Program

Programs without in-vessel capsules use alternative dosimetry to monitor neutron fluence during the period of extended operation.

If all surveillance capsules have been removed, operating restrictions are established to ensure that the plant is operated under conditions to which the surveillance capsules were exposed. The exposure conditions of the reactor vessel are monitored to ensure that they continue to be consistent with those used to project the effects of embrittlement to the end of license. If the reactor vessel exposure conditions (neutron flux, spectrum, irradiation temperature, etc.) are altered, then the basis for the projection to 60 or more years is reviewed and, if deemed appropriate, modifications are made to the Reactor Vessel Surveillance program. Any changes to the Reactor Vessel Surveillance program must be submitted for NRC review and approval in accordance with 10 CFR Part 50, Appendix H.

275. Monitoring and Trending: The program provides reactor vessel embrittlement data for the time limited aging analyses (TLAAs) on neutron irradiation embrittlement (e.g., upper-shelf energy, pressurized thermal shock and pressure-temperature limits evaluations, etc.) for 60 years. The programs are designed to periodically remove and test capsules for monitoring and trending purposes. Refer to the Standard Review Plan for License Renewal, Section 4.2, for the NRC acceptance criteria and review procedures for reviewing TLAAs for neutron irradiation embrittlement.

The TLAAs are projected in accordance with NRC Regulatory Guide (RG) 1.99, Rev. 2, “Radiation Embrittlement of Reactor Vessel Materials,” and the pressurized thermal shock rules (10 CFR 50.61 and 10 CFR 50.61a). When using NRC RG 1.99, Rev. 2, or equivalent provisions in 10 CFR 50.61, a licensee has a choice of the following:

(a) Neutron Embrittlement Using Chemistry Tables and Upper Shelf Energy Figures

An applicant may use the tables and figures in NRC RG 1.99, Rev. 2, to project the extent of reactor vessel neutron embrittlement for the period of extended operation based on material chemistry and neutron fluence. This is described as Regulatory Position 1 in NRC RG 1.99, Rev. 2.

(b) Neutron Embrittlement Using Surveillance Data

When credible surveillance data are available, the extent of reactor vessel neutron embrittlement for the period of extended operation must be projected according to Regulatory Position 2 in NRC RG 1.99, Rev. 2, based on best fit of the surveillance data. The credible data could be collected during the current and extended operating term. A plant-specific program or an integrated surveillance program during the period of extended operation provides for the collection of additional data.

A program that determines embrittlement by using NRC RG 1.99, Rev. 2, tables and figures (item [a]) uses the applicable limitations in Regulatory Position 1.3 of NRC RG 1.99, Rev. 2. The limits are based on material properties, temperature, material chemistry, and neutron fluence.

The program that determines embrittlement by using surveillance data (item [b]) defines the applicable bounds of the data, such as cold leg operating temperature and neutron fluence. These bounds are specific for the referenced surveillance data. For example, the plant-specific data could be collected within a smaller temperature range than that in NRC RG 1.99, Rev. 2.

The reactor vessel monitoring program provides that if future plant operations exceed these limitations or bounds, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of reactor vessel embrittlement is evaluated and the NRC is notified.

276. Acceptance Criteria: Reactor vessel embrittlement projections comply with 10 CFR Part 50, Appendix G, requirements and 10 CFR 50.61 or 10 CFR 50.61a limits through the period of extended operation.

Acceptable pressure-temperature curves for heatup and cooldown of the unit are maintained in Technical Specifications. The operational effective full power years shall not exceed the Technical Specification limits for the pressure-temperature curves.

277. Corrective Actions: Results of surveillance capsule testing is incorporated into site operating limitations. Affected documents may include pressure-temperature (P-T) curves in the Technical Specifications, Updated Final Safety Analysis Report, and operating procedures. If changes to the P-T curves are required, a licensing basis change shall be prepared and the revised curves shall be submitted to the NRC. A submittal is only required if the existing P-T curves are determined to be non-conservative.

If embrittlement projections indicate that material upper-shelf energy will drop below 50 ft-lbs, the margins of safety against fracture is demonstrated to be equivalent to those of Appendix G of ASME Section XI.

If RT_{PTS} for a material in the beltline is projected to exceed the screening criteria in 10 CFR 50.61 or 10 CFR 50.61a using the end of extended license fluence, a site may implement flux reduction programs that are reasonably practicable to avoid exceeding this criterion. If no reasonably practicable flux reduction program can avoid exceeding the screening criteria, the site submits a safety analysis to determine actions to prevent potential failure of the reactor vessel as a result of postulated events if continued operation beyond the screening criteria is allowed.

If a capsule is not withdrawn as scheduled, the NRC is notified and a revised withdrawal schedule is submitted to the NRC.

Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

278. Confirmati on Process: Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls

279. Administrative Controls: The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

280. Operating Experience: The existing reactor vessel material surveillance program provides sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) determine the need for operating restrictions on the inlet temperature, neutron spectrum, and neutron flux.

References

10 CFR Part 50, Appendix G, *Fracture Toughness Requirements*, Office of the Federal Register, National Archives and Records Administration, 2009.

10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASTM E 185, S*tandard Practice for Conducting Surveillance Tests of Light-Water Cooled Nuclear Power Reactor Vessels*, American Society for Testing Materials, Philadelphia, PA. (Versions of ASTM E 185 to be used for the various aspects of the reactor vessel surveillance program are as specified in 10 CFR Part 50, Appendix H.)

NRC Regulatory Guide 1.99, Rev. 2, *Radiation Embrittlement of Reactor Vessel Materials*, U.S. Nuclear Regulatory Commission, May 1988.

XI.M32 ONE-TIME INSPECTION

Program Description

A one-time inspection of selected components is used to verify the system-wide effectiveness of an aging management program (AMP) that is designed to prevent or minimize aging to the extent that it will not cause the loss of intended function during the period of extended operation. For example, effective control of water chemistry can prevent some aging effects and minimize others. However, there may be locations that are isolated from the flow stream for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. This program provides inspections that verify that unacceptable degradation is not occurring. It also may trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.

The program includes measures to verify the effectiveness of an AMP and confirm the insignificance of an aging effect. Situations in which additional confirmation is appropriate include (a) an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence; or (b) an aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse than that generally expected. For these cases, there is to be confirmation that either the aging effect is indeed not occurring or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation. Class 1 piping less than nominal pipe size (NPS) 4 is addressed in Chapter XI.M35, “One Time Inspection of ASME Code Class 1 Small Bore-Piping.”

The elements of the program include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined; and (d) evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could jeopardize an intended function before the end of the period of extended operation.

An acceptable program to verify system-wide effectiveness of an AMP may consist of a one-time inspection of selected components and susceptible locations in the system. Verification may include a review of routine maintenance, repair, or inspection records to confirm that these components have been inspected for aging degradation and that significant aging degradation has not occurred. A one-time inspection program is acceptable when using Chapter XI.M2, “Water Chemistry”; Chapter XI.M30, “Fuel Oil Chemistry”; and Chapter XI.M39, “Lubricating Oil Analysis,” programs or where the environment in the period of extended operation is expected to be equivalent to that in the prior 40 years and for which no aging effects have been observed. However, one-time inspection for all other environments, or any other action or program created to verify the effectiveness of an AMP and confirm the absence of an aging effect, is to be reviewed by the staff on a plant-specific basis.

This program cannot be used for structures or components with known age-related degradation mechanisms or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections should be proposed in these cases.

Evaluation and Technical Basis

281. ***Scope of Program:*** The scope of this program includes systems and components that are subject to aging management using the aging management programs Chapter XI.M2, "Water Chemistry"; Chapter XI.M30, "Fuel Oil Chemistry"; and Chapter XI.M39, "Lubricating Oil Analysis," and for which no aging effects have been observed. The scope of this program also may include other components and materials where the environment in the period of extended operation is expected to be equivalent to that in the prior 40 years and for which no aging effects have been observed.

The program cannot be used for structures or components with known age-related degradation mechanisms or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections should be proposed in these cases.

282. ***Preventive Actions:*** One-time inspection is a condition monitoring program. It does not include methods to mitigate or prevent age-related degradation.

283. ***Parameters Monitored/Inspected:*** The program monitors parameters directly related to the age-related degradation of a component. Examples of parameters monitored and the related aging effect are provided in the table in Element 4, below. Inspection is performed using a variety of nondestructive examination (NDE) methods, including visual, volumetric, and surface techniques.

284. ***Detection of Aging Effects:*** Elements of the program include: (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience; (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur; and (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined. Where practical, the inspection includes a representative sample of the system population and focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. For components managed by the Chapter XI.M2, Water Chemistry"; Chapter XI.M30, "Fuel Oil Chemistry"; and Chapter XI.M39, "Lubricating Oil Analysis," programs, 20 percent of the population with a maximum sample of 25 constitutes a representative sample size. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection should be included as part of the program's documentation.

The program relies on established NDE techniques, including visual, ultrasonic, and surface techniques similar to those specified in American Society of Mechanical Engineers (ASME) Code, Section XI[1]; inspections are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR Part 50, Appendix B. In addition, a description of Enhanced Visual Examination (EVT-1) is found in Boiling Water Reactor Vessel and Internals Project (BWRVIP)-03 and Materials Reliability Program (MRP)-228.

[1] Refer to the GALL Report, Volume 2, Chapter I, for application of other editions of the ASME Code, Section XI.

The inspection and test techniques should have a demonstrated history of effectiveness in detecting the aging effect of concern. Typically, the one-time inspections should be performed as indicated in the following table.

Examples of Parameters Monitored or Inspected and Aging Effect for Specific Structure or Component[1]			
Aging Effect	**Aging Mechanism**	**Parameter(s) Monitored**	**Inspection Method**[2]
Loss of Material	Crevice Corrosion	Surface Condition, Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (ultrasonic testing [UT])
Loss of Material	Galvanic Corrosion	Surface Condition, Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (UT)
Loss of Material	General Corrosion	Surface Condition, Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (UT)
Loss of Material	MIC	Surface Condition, Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (UT)
Loss of Material	Pitting Corrosion	Surface Condition, Wall Thickness	Visual (VT-1 or equivalent) and/or Volumetric (UT)
Loss of Material	Erosion	Surface Condition, Wall Thickness	Visual (VT-3 or equivalent) and/or Volumetric (UT)
Loss of Heat Transfer	Fouling	Tube Fouling	Visual (VT-3 or equivalent) or Enhanced VT-1 for CASS
Cracking	SCC or Cyclic Loading	Surface Condition, Cracks	Enhanced Visual (VT-1 or equivalent) or Surface Examination (magnetic particle, liquid penetrant) or Volumetric (radiographic testing or UT)

With respect to inspection timing, the population of components inspected before the end of the current operating term needs to be sufficient to provide reasonable assurance that the aging effect will not compromise any intended function at any time during the period of extended operation. Specifically, inspections need to be completed early enough to ensure that the aging effects that may affect intended functions early in the period of extended operation are appropriately managed. Conversely, inspections need to be timed to allow the inspected components to attain sufficient age to ensure that the aging effects with long incubation periods (i.e., those that may affect intended functions near the end of the period of extended operation) are identified. Within these constraints, the applicant should schedule the inspection no earlier than 10 years prior to the period of extended operation and in such a way as to minimize the impact on plant operations. As a plant will have

[1] The examples provided in the table may not be appropriate for all relevant situations. If the applicant chooses to use an alternative to the recommendations in this table, a technical justification should be provided as an exception to this AMP. This exception should list the AMR line item component, examination technique, acceptance criteria, evaluation standard, and a description of the justification.
[2] Visual inspection may be used only when the inspection methodology examines the surface potentially experiencing the aging effect.

accumulated at least 30 years of use before inspections under this program begin, sufficient time will have elapsed for aging effects, if any, to be manifest.

An aging management review (AMR) line item in the Generic Aging Lessons Learned (GALL) Report, together with Chapter XI.M2, “Water Chemistry,” identifies this program as acceptable to manage the aging effect of erosion in the stainless steel miniflow orifice exposed to treated, borated water in the emergency core cooling system at some pressurized water reactors. When this program is credited to manage the aging effect of erosion in this component, the miniflow orifice should be explicitly examined. The staff believes that potential age-related degradation in this miniflow orifice cannot be inferred by examination of other representative components.

285. ***Monitoring and Trending:*** This is a one-time inspection program. Monitoring and trending are not applicable.

286. ***Acceptance Criteria*****:** Any indication or relevant conditions of degradation detected are evaluated. Acceptance criteria may be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. For example, ultrasonic thickness measurements are compared to predetermined limits.

287. ***Corrective Actions:*** Unacceptable inspection findings are evaluated in accordance with the site’s corrective action process to determine appropriate corrective actions and the need for subsequent (including periodic) inspections under another AMP. Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

288. ***Confirmation Process:*** Confirmation processes to ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective are implemented through the site QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

289. ***Administrative Controls:*** Administrative controls to provide a formal review and approval for corrective actions are implemented through the site QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

290. ***Operating Experience:*** The elements that comprise inspections associated with this program (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice. An applicant’s operating experience with detection of aging effects should be adequate to demonstrate that the program is capable of detecting the presence or noting the absence of aging effects in the components, materials, and environments where one-time inspection is used to confirm system-wide effectiveness of another preventive or mitigative AMP.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2009.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition (no addenda), American Society of Mechanical Engineers, New York, NY.

BWRVIP-03, *BWR Vessel and Internals Project: Reactor Pressure Vessel and Internals Examination Guidelines* (EPRI TR-105696- R6, January 6, 2004).

MRP-228, *Materials Reliability Program: Inspection Standard for PWR Internals*, 2009.

XI.M33 SELECTIVE LEACHING OF MATERIALS

Program Description

This aging management program (AMP) determines the acceptability of the components that may be susceptible to selective leaching and assesses their ability to perform the intended function during the period of extended operation. The program for selective leaching of materials ensures the integrity of the components made of gray cast iron[20] and uninhibited brass containing > 15% zinc[21], exposed to a raw water, brackish water, closed cooling water, treated water, or ground water environment that may lead to selective leaching of one of the metal components where there has not been previous experience of selective leaching. The AMP includes a one-time visual inspection of selected components that may be susceptible to selective leaching, coupled with either hardness measurements (where feasible, based on form and configuration), or mechanical examination techniques. These techniques can determine whether loss of materials due to selective leaching is occurring and whether selective leaching will affect the ability of the components to perform their intended function for the period of extended operation.

The selective leaching process involves the preferential removal of one of the alloying elements from the material, which leads to the enrichment of the remaining alloying elements. Dezincification (loss of zinc from brass) and graphitization (removal of iron from cast iron) are examples of such a process. Susceptible materials, high temperatures, stagnant-flow conditions, and a corrosive environment, such as acidic solutions for brasses with high zinc content and dissolved oxygen, are conducive to selective leaching.

Although the program does not provide guidance on preventive action, it is noted that monitoring of water chemistry to control pH and concentration of corrosive contaminants and treatment to minimize dissolved oxygen in water are effective in reducing selective leaching.

Evaluation and Technical Basis

291. ***Scope of Program:*** This program applies only to plants where there has not been previous experience of selective leaching. If this is not the case, a plant-specific program should be proposed in lieu of this program. Components include piping, valve bodies and bonnets, pump casings, and heat exchanger components that are susceptible to selective leaching. The materials of construction for these components may include cast grey iron and uninhibited brass containing greater than 15% zinc. These components may be exposed to raw water, treated water, closed cooling water, ground water, water contaminated fuel oil, or water contaminated diesel oil.

292. ***Preventive Actions:*** The one-time visual inspection and hardness measurement is a conditioning monitoring program. It contains no preventive actions.

293. ***Parameters Monitored/Inspected:*** The one-time visual inspection and hardness measurement includes close examination of a select set of components to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation.

[20] Ductile or malleable iron are not subject to selective leaching.
[21] Red brass (Zn ≤ 15%) and all inhibited brasses are not subject to selective leaching.

294. ***Detection of Aging Effects:*** The visual inspection and hardness measurement or other mechanical examination techniques, such as destructive testing (when the opportunity arises), chipping, or scraping, is a one-time inspection within the last 5 years prior to entering the period of extended operation. Because selective leaching is a slow acting corrosion process, this measurement is performed just before the beginning of the license renewal period. Follow-up of unacceptable inspection findings includes an evaluation using the corrective action program and a possible expansion of the inspection sample size and location.

Where practical, the inspection includes a representative sample of the system population and focuses on the bounding or lead components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. Twenty percent of the population with a maximum sample of 25 constitutes a representative sample size. Otherwise, a technical justification of the methodology and sample size used for selecting components for one-time inspection should be included as part of the program's documentation. Each group of components with different material/environment combinations is considered a separate population.

Selective leaching generally does not cause changes in dimensions and is difficult to detect. However, in certain brasses it causes plug-type dezincification, which can be detected by visual inspection. One acceptable procedure is to visually inspect the susceptible components closely and conduct Brinell hardness testing (where feasible, based on form and configuration or other industry-accepted mechanical inspection techniques) on the inside surfaces of the selected set of components to determine if selective leaching has occurred. If it is occurring, an engineering evaluation is initiated to determine acceptability of the affected components for further service.

295. ***Monitoring and Trending:*** This is a one-time inspection to determine if selective leaching is an issue. Monitoring and trending is not required.

296. ***Acceptance Criteria:*** The acceptance criteria are no visible evidence of selective leaching or no more than a 10 percent decrease in hardness. For copper alloys with greater than 15 percent zinc, the criteria is no noticeable change in color from the normal yellow color to the reddish copper color.

297. ***Corrective Actions:*** Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria. The corrective actions program ensures that conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions. Unacceptable inspection findings result in additional inspection(s) being performed, which may be on a periodic basis, or in component repair or replacement.

298. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

299. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

300. ***Operating Experience:*** The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. Selective leaching has been detected in components constructed from cast iron, brass, bronze, and aluminum bronze. Components affected have included valve bodies, pump casings, piping, and cast iron fire protection piping buried in soil.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

EPRI TR-107514, *Age Related Degradation Inspection Method and Demonstration*, Electric Power Research Institute, April 1998.

Fontana, M. G., *Corrosion Engineering*, McGraw Hill, p 86-90, 1986.

NUREG-1705, *Safety Evaluation Report Related to the License Renewal of Calvert Cliffs Nuclear Power Plant, Units 1 and 2*, U.S. Nuclear Regulatory Commission, December 1999.

NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, U.S. Nuclear Regulatory Commission, March 2000.

NUREG-1930, *Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Units 2 and 3*, U.S. Nuclear Regulatory Commission, November 2009.

Schweitzer, P. A., *Encyclopedia of Corrosion Technology 2nd Ed*, Marcel Dekker, p 201-202. March 17, 2004.

XI.M34 BURIED PIPING AND TANKS INSPECTION

Program Description

This program includes preventive measures to mitigate corrosion and periodic inspections to manage the aging effects of corrosion on the external surface of buried piping and tanks to ensure that their pressure-retaining capacity is maintained. This program provides for the aging management of buried piping and tanks constructed from materials that include steel, stainless steels (e.g., AISI Type 304, 304L, 304LN, 316, 316L, 316LN), duplex stainless steels, super austenitic stainless steels (such as AL6XN specialty steel), titanium alloys, aluminum alloys, copper alloys and high density polyethylene (HDPE) or other rigid polymeric piping, fiberglass pipe, concrete cylinder pipe, and concrete pipe. Gray cast iron, which is included under the definition of steel, is also subject to a loss of material due to selective leaching, which is an aging effect managed under Chapter XI.M33, “Selective Leaching of Materials.”

This program involves the inspection of buried piping and tanks when they are excavated during maintenance and during periodic focused inspections when the surface of the piping or tanks is exposed. The program also includes a one-time inspection of the interior surfaces of buried metallic tanks.

This program may be used with another aging management program that manages the aging effects on the interior of the buried piping. An example is to use the Buried Piping and Tanks Inspection program for the exterior of buried service water piping, and the Open-cycle Cooling Water program for the interior of the piping.

Evaluation and Technical Basis

301. ***Scope of Program***: The Buried Piping and Tanks Inspection program is used to manage the effects of aging for buried piping and tanks constructed of steel, stainless steels, duplex stainless steels, super austenitic stainless steels, titanium alloys, aluminum alloys, copper alloys and HDPE and other rigid polymeric piping, fiberglass pipe, concrete cylinder pipe, concrete pipe, and gray cast iron. Typical systems that are buried include service water piping and components, condensate storage transfer lines, fuel oil and lubricating oil lines, fire protection piping and piping components (fire hydrants), and storage tanks.

302. ***Preventive Actions:*** In accordance with industry standards (e.g., NACE, AWWA, etc.), underground steel piping and tanks are coated during installation with a protective coating system, such as coal tar epoxy or enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment. The need to use coatings and wrappings for piping constructed from metallic materials other than steel is made on a case-by-case basis. Piping constructed from fiberglass, high density polyethylene and other rigid polymeric materials, or concrete are not normally coated or wrapped.

To prevent damage to the pipe and coating, backfill around the excavated piping should be free of large rocks, trash, debris, ice, and other miscellaneous solid materials. If the tanks are anchored to counteract buoyant forces, the anchor material should consist of flat straps that are electrically isolated from the tanks. Buried steel tanks have a coating on the exterior surface and may have an interior coating. Tanks constructed from metallic materials other than steel may be coated, on a case-by-case basis.

303. ***Parameters Monitored/Inspected:*** This program monitors the loss of material in piping, and tanks, or damage to coating/wrapping integrity that is directly related to corrosion of the external surfaces. Coatings and wrappings are inspected by visual techniques. Any evidence of damaged wrapping or coating defects, such as coating perforation, holidays, or other damage, can indicate possible corrosion damage to the external surface of piping and tanks. Uncoated metallic piping is visually examined for evidence of corrosion and the presence of mechanical damage. In particular, the piping is examined for evidence of general corrosion, pitting, crevice corrosion, microbiologically influenced corrosion (MIC), and cracking. Mechanical damage might be important because it may introduce residual stress that could be the initiation site for stress corrosion cracking. High density polyethylene, other rigid polymeric materials, and fiberglass piping is visually inspected for evidence of blistering and cracking. Concrete piping is examined visually for evidence of exposure of rebar, corrosion of the rebar, spalling, or cracking.

Buried tank interior surfaces are ultrasonically (UT) inspected to determine if wall thinning has occurred from external corrosion.

304. ***Detection of Aging Effects:*** Inspections performed to confirm that coating and wrapping of coated piping is intact and are an effective method to ensure that corrosion of external surfaces has not occurred and the intended function is maintained. Metallic piping that is not coated is visually examined for evidence of general corrosion, pitting, crevice corrosion, or MIC. Nonmetallic piping is visually examined for evidence of cracking, blistering, or other signs of deterioration.

Buried piping and tanks are inspected periodically using focused inspections in areas with the highest likelihood of corrosion problems and in areas with a history of corrosion problems. Opportunistic inspections are conducted whenever the piping or tanks are accessible.

The applicant is to conduct a focused visual inspection of the buried piping three times in the 10 years prior to entering the period of extended operation and three times in the first 10 years after entering the period of extended operation unless an opportunistic inspection has been conducted in any 3-year period. These inspections are conducted approximately every 3 years. In addition to the visual inspection, the inspection should be supplemented by newer techniques, such as guided wave UT, to determine if wall loss is occurring in a larger portion of the piping than the section uncovered for visual inspection. These visual inspections and enhanced inspections should be conducted on each system that contains buried piping and for each material of construction for the piping.

Potential corrosion of tank surfaces exposed to soil is determined by taking UT thickness measurements of the tank bottom walls and ceiling within 10 years of entering the period of extended operation. The UT measurements should be conducted prior to entering the period of extended operation. A representative sample size is 20 percent of the population with a maximum sample of 25. Otherwise, a technical justification of the methodology and sample size used should be included as part of the program's documentation.

305. ***Monitoring and Trending:*** Results of previous inspections are used to identify susceptible locations and the necessity to conduct follow-up inspections. For example, if general corrosion is detected, it may be necessary to determine the extent of corrosion and perform trending to estimate where the piping does not meet the minimum wall thickness requirement.

306. ***Acceptance Criteria:*** For coated piping, there should be no evidence of coating degradation. If coating degradation is observed, the coating should be repaired. An evaluation should be conducted to determine the cause of coating degradation and the decision made whether additional inspections are required. If coated or uncoated metallic piping shows evidence of corrosion, the remaining wall thickness should be determined to ensure that the minimum wall thickness remains. This may include different values for large area minimum wall thickness, and local area wall thickness. An evaluation should be conducted to determine the cause of corrosion and the decision made whether additional inspections are required. Nonmetallic piping will be visually examined for evidence of cracking or blistering. Concrete piping should have no spalling of concrete, no exposed rebar, no corrosion of rebar, and no cracking.

307. ***Corrective Actions:*** The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

308. ***Confirmation Process:*** The confirmation process ensures that preventive actions are adequate and that appropriate corrective actions have been completed and are effective. The confirmation process for this program is implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

309. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

310. ***Operating Experience:*** Operating experience shows that the program described here is effective in managing corrosion of external surfaces of buried steel piping and tanks. However, the applicant’s plant-specific operating experience needs to be further evaluated to determine whether some augmented actions may be necessary for the period of extended operation.

For existing buried tanks, information should be gathered concerning the history of the tank. The history of the tank should include a physical description of the tank and operating history. The physical description of the tank should include size, configuration, and condition of the tank; materials of construction; electrical continuity; presence of other underground structures; and presence of pavement. The operating history should include date of installation and as-built drawings; results of tightness testing; results of internal inspections and other industry accepted methods of integrity assessment; the leak history of the tank, including the date, location, and types of each leak; repairs or replacements of system components, including the reason for repairs or replacements; and any experience with cathodic protection systems in the past.

During June 2009, an active leak was discovered at Dresden in underground piping associated with the condensate storage tank (CST). The leak was discovered because elevated levels of tritium were detected. There were similar leaks in buried piping in 2004 and 2006, and those sections of piping were replaced.

In May 2009, diesel/fuel oil odor was identified in the groundwater near the diesel generator building at Hatch. The area was excavated to find the source of the leak.

On September 6, 2005, a service water leak was discovered at Dresden from an buried service water header after 38 years of service. The cause of the leak was either failure of the external coating or damage caused by improper backfill. The service water header was relocated above ground.

On February 21, 2005, a leak was detected in a 4-inch condensate storage supply line at Callaway Unit 1. The cause of the leak was MIC or under deposit corrosion. The leak was repaired in accordance with the American Society of Mechanical Engineers (ASME) Section XI, “Repair/Replacement Plan.”

On August 19, 2008, a flexible PVC pipe ruptured in the service water system at St. Lucie. The rupture was related to Tropical Storm Fay, which washed away the soil where the piping was buried and washed additional soil away beneath the piping. This caused the PVC piping to sag and break free at the connecting joints. This section of piping was repaired.

On February 2009, a leak was discovered on the return line to the CST for Indian Point Unit 2. As a result of this operating experience, the applicant plans to include a risk assessment to classify in-scope buried piping segments and buried tanks as high, medium, or low impact of leakage based on the safety classification, the hazard posed by the fluids in the piping and tanks, and the impact of leakage on reliable plant operation. The applicant considers the piping or tank material of construction, soil resistivity, drainage, the presence of cathodic protection, and the type of coating for corrosion risk.

The applicant’s modification to the Buried Piping and Tanks Inspection program significantly increases the number of inspections of buried piping and tanks. Rather than conduct one inspection prior to entering the period of extended operation, consistent with the Generic Aging Lessons Learned (GALL) Report where site-specific operating experience is not a factor, the applicant conducts 15 periodic inspections for Indian Point Unit 2 prior to entering the period of extended operation in 2013, and 30 periodic inspections for Indian Point Unit 3 prior to entering the period of extended operation in 2015. Also, because of the recent leak in the CST return line, the applicant plans to conduct six additional inspections in 2009 at lower level elevations for the service water and auxiliary feedwater systems, based on a determination that these locations have the highest risk of corrosion due to their proximity to the water table.

In April 2009, Oyster Creek had a leak in an aluminum pipe where it went through a concrete wall. The piping was for the condensate transfer system. The failure was caused by degradation of the coating in contact with the concrete. The piping was replaced with piping in kind.

In October 2007, Byron reported degradation of an essential service water piping resulting in an NRC special inspection in February 2008. INPO issued an SER discussing the degradation of the essential service water piping and concluded the degradation was caused by exposure to extreme conditions (including being buried).

In March 2006, Byron reported elevated tritium levels near buried piping.

In December 2005, Braidwood reported elevated tritium levels near buried piping.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

XI.M35 ONE-TIME INSPECTION OF ASME CODE CLASS 1 SMALL-BORE PIPING

Program Description

This program augments the existing American Society of Mechanical Engineers (ASME) Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and systems less than 4 inches nominal pipe size (NPS<4), which includes pipes, fittings, branch connections, and all full penetration and partial penetration (socket) welds. According to Table IWB-2500-1, Examination Category B-J Item No. B9.21 of the current ASME Code, for small-bore Class 1 piping, a surface examination should be included for piping less than NPS 4 and greater than or equal to NPS 1. Also, Examination Category B-P requires system leakage and hydrostatic tests. However, the staff believes that for a one-time inspection to detect cracking resulting from thermal and mechanical loading or intergranular stress corrosion, the inspection should be a volumetric examination. This is to provide additional assurance that either aging of small-bore ASME Code Class 1 piping is not occurring or the aging is insignificant, such that an aging management program (AMP) is not warranted. This program is applicable only to plants that have not experienced cracking of ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading. Should evidence of cracking of ASME Code Class 1 small-bore piping be revealed by a one-time inspection or previous operating experience, periodic inspection will be proposed, as managed by a plant-specific AMP.

Evaluation and Technical Basis

311. ***Scope of Program:*** This program is a one-time inspection of a sample of ASME Code Class 1 piping less than NPS 4. This program is applicable only to plants that have not experienced cracking of ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading. Should evidence of cracking of ASME Code Class 1 small-bore piping be revealed by a one-time inspection or previous operating experience, periodic inspection will be proposed, as managed by a plant-specific AMP. The program includes measures to verify that degradation is not occurring; thereby either confirming that there is no need to manage aging-related degradation or validating the effectiveness of any existing AMP for the period of extended operation. The one-time inspection program for ASME Code Class 1 small-bore piping includes locations that are susceptible to cracking. Guidelines for identifying piping susceptible to potential effects of thermal stratification or turbulent penetration are provided in EPRI Report 1000701, "Interim Thermal Fatigue Management Guideline (MRP-24)."

312. ***Preventive Actions:*** This program is a condition monitoring activity independent of methods to mitigate or prevent degradation.

313. ***Parameters Monitored/Inspected:*** This inspection detects cracking in ASME Code Class 1 small-bore piping.

314. ***Detection of Aging Effects:*** The inspection is designed to provide assurance, in plants that have not experienced cracking of ASME Code Class 1 small-bore piping due to stress corrosion or thermal and mechanical loading, that aging of this piping is not occurring or that the effects of aging are not significant. For ASME Code Class 1 small-bore piping, one-time inspections using volumetric examination are performed on selected weld locations to detect cracking.

Aging management review line items in the Generic Aging Lessons Learned (GALL) Report identify this program as acceptable to manage the aging effect of cracking due to stress corrosion cracking in stainless steel or nickel-alloy vessel flange leak detection lines of both boiling water reactors and pressurized water reactors. When this program is credited to manage the aging effect of cracking in these components, the leak detection line should be explicitly examined; the staff believes that potential age-related degradation in the leak detection lines cannot be inferred by examination of other representative components.

315. ***Monitoring and Trending:*** This is a one-time inspection to determine whether cracking in ASME Code Class 1 small-bore piping resulting from stress corrosion or thermal and mechanical loading is an issue. A one-time volumetric inspection is an acceptable method for confirming that cracking of ASME Code Class 1 small-bore piping, as a result of stress corrosion or thermal and mechanical loading, is not occurring in plants that have not experienced cracking due to these aging effects. However, evaluation of the inspection results may indicate the need for additional or periodic examinations (i.e., a plant-specific AMP for Class 1 small-bore piping using volumetric inspection methods consistent with ASME Code, Section XI, Subsection IWB). This inspection should be performed at a sufficient number of locations to ensure an adequate sample. This number, or sample size, is based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations.

316. ***Acceptance Criteria:*** If flaws or indications exceed the acceptance criteria of ASME Code, Section XI, Paragraph IWB-3400, they are evaluated in accordance with ASME Code, Section XI, Paragraph IWB-3131; additional examinations are performed in accordance with ASME Code, Section XI, Paragraph IWB-2430.

317. ***Corrective Actions:*** The site corrective action program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

318. Confirmati on Process: As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

319. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

320. ***Operating Experience*****:** This inspection uses volumetric inspection techniques with demonstrated capability and a proven industry record to detect cracking in piping weld and base material. However, the application of the specific technique to ASME Code Class 1 small-bore piping needs to be qualified before the examination.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2009.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2004 edition[1] (no addenda), American Society of Mechanical Engineers, New York, NY.

EPRI Report 1000701, *Interim Thermal Fatigue Management Guideline (MRP-24)*, Electric Power Research Institute, January 2001. (ADAMS Accession No. ML010810162)

NRC Information Notice 97-46, *Unisolable Crack in High-Pressure Injection Piping*, U.S. Nuclear Regulatory Commission, July 9, 1997.

[1] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

XI.M36 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

Program Description

The External Surfaces Monitoring of Mechanical Components program is based on system inspections and walkdowns. This program consists of periodic visual inspections of metallic and polymeric components such as piping, piping components, ducting, polymeric components, and other components within the scope of license renewal and subject to aging management review (AMR) in order to manage aging effects. The program manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking, and change in material properties. When appropriate for the component and material, manipulation may be used to augment visual inspection to confirm the absence of elastomer hardening and loss of strength. Loss of material due to boric acid corrosion is managed by the Boric Acid Corrosion program (XI.M10).

Evaluation and Technical Basis

321. ***Scope of Program:*** This program visually inspects the external surface of in-scope mechanical components and monitors external surfaces of metallic components in systems within the scope of license renewal and subject to AMR for loss of material and leakage. This program also visually inspects and monitors the external surfaces of polymeric components in mechanical systems within the scope of license renewal and subject to AMR for change in material properties (such as hardening and loss of strength), cracking, and loss of material due to wear. This program manages the effects of aging of polymer materials in all environments to which these materials are exposed.

The program may also be credited with managing loss of material from internal surfaces of metallic components and with loss of material, hardening and change in material properties from the internal surfaces of polymers, for situations in which material and environment combinations are the same for internal and external surfaces such that external surface condition is representative of internal surface condition. When credited, the program should describe the component internal environment and the credited similar external component environment inspected.

322. ***Preventive Actions:*** The External Surfaces Monitoring of Mechanical Components program is a condition monitoring program that does not include preventive actions.

323. ***Parameters Monitored/Inspected:*** The External Surfaces Monitoring of Mechanical Components program utilizes periodic plant system inspections and walkdowns to monitor for material degradation and leakage. This program inspects components such as piping, piping components, ducting, polymeric components, and other components. For metallic components, coatings deterioration is an indicator of possible underlying degradation. The aging effects for flexible polymeric components may be monitored through a combination of visual inspection and manual or physical manipulation of the material. “Manual or physical manipulation of the material” means touching, pressing on, flexing, bending, or otherwise manually interacting with the material. The purpose of the manual manipulation is to reveal changes in material properties, such as hardness, and to make the visual examination process more effective in identifying aging effects such as cracking.

Examples of inspection parameters for metallic components include:

- corrosion and material wastage (loss of material)
- leakage from or onto external surfaces (loss of material)
- worn, flaking, or oxide-coated surfaces (loss of material)
- corrosion stains on thermal insulation (loss of material)
- protective coating degradation (cracking, flaking, and blistering)

Examples of inspection parameters for polymers include:

- surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”)
- discoloration
- exposure of internal reinforcement for reinforced elastomers
- hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation

324. ***Detection of Aging Effects:*** This program manages aging effects of loss of material, cracking, and change in material properties using visual inspection. For coated surfaces, confirmation of the integrity of the paint or coating is an effective method for managing the effects of corrosion on the metallic surface.

A visual inspection (VT-3 or equivalent) is conducted for metallic and polymeric component surfaces at least once per refueling cycle. This frequency accommodates inspections of components that may be in locations that are normally only accessible during outages. System walkdowns are normally performed on a frequency of at least once per fuel cycle. Surfaces that are inaccessible or not readily visible during plant operations and refueling outages are inspected at such intervals that would ensure the components intended function is maintained. Surfaces that are insulated may be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure the components’ intended function is maintained. The intervals of inspections may be adjusted as necessary based on plant-specific inspection results and industry operating experience.

Visual inspection (VT-3 or equivalent) of flexible polymeric components is performed whenever the component surface is accessible. Visual inspection will identify indirect indicators of flexible polymer hardening and loss of strength to include the presence of surface cracking, crazing, discoloration, and for elastomers with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. Visual inspection should be 100 percent of accessible components. Visual inspection will identify direct indicators of loss of material due to wear to include dimensional change, scuffing, and for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. Manual or physical manipulation can be used to augment visual inspection to confirm the absence of hardening and loss of strength for flexible polymeric materials (e.g., HVAC flexible connectors), where appropriate. The sample size for manipulation should be at least 10 percent of available surface area. Hardening and loss of strength and loss of material due to wear for flexible polymeric materials is expected to be detectable prior to any loss of intended function.

This program is credited with managing the following aging effects.

- loss of material for external surfaces
- loss of material for internal surfaces exposed to the same environment as the external surface

- cracking and change in material properties (hardening and loss of strength) of flexible polymers

325. ***Monitoring and Trending:*** Visual inspection and manual or physical manipulation activities are performed and associated personnel are qualified in accordance with site controlled procedures and processes. The External Surfaces Monitoring of Mechanical Components program uses standardized monitoring and trending activities to track degradation. Deficiencies are documented using approved processes and procedures such that results can be trended. However, the program does not include formal trending. Inspections are performed at frequencies identified in Element 4, "Detection of Aging Effects."

326. ***Acceptance Criteria:*** For each component/aging effect combination, the acceptance criteria are defined to ensure that the need for corrective actions will be identified before loss of intended functions. For metallic surfaces, any indications of relevant degradation detected are evaluated. For stainless steel surfaces, a clean shiny surface is expected. The appearance of rust spots may indicate the loss of material on the stainless steel surface. For aluminum and copper alloys exposed to marine or industrial environments, any indications of relevant degradation detected are evaluated. For flexible polymers, a uniform surface texture and uniform color with no unanticipated dimensional change is expected. Any abnormal surface condition may be an indication of an aging effect for metals and for polymers. For flexible materials to be considered acceptable, the inspection results should indicate that the flexible polymer material is in "as new" condition (e.g., the hardness, flexibility, physical dimensions, and color of the material are unchanged from when the material was new). Cracks should be absent within the material. For rigid polymers, surface changes affecting performance, such as erosion, cracking, crazing, checking, and chalking, are subject to further investigation. Acceptance criteria include design standards, procedural requirements, current licensing basis, industry codes or standards, and engineering evaluation.

327. ***Corrective Actions:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

328. ***Confirmation Process***: As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

329. ***Administrative Controls*****:** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

330. ***Operating Experience:*** External surfaces inspections via system inspections and walkdowns have been in effect at many utilities since the mid 1990's in support of the Maintenance Rule (10 CFR 50.65) and have proven effective in maintaining the material condition of plant systems. The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

INPO Good Practice TS-413, *Use of System Engineers*, INPO 85-033, May 18, 1988.

EPRI Technical Report 1007933, *Aging Assessment Field Guide*, December 2003.

EPRI Technical Report 1009743, *Aging Identification and Assessment Checklist*, August 27, 2004.

XI.M37 FLUX THIMBLE TUBE INSPECTION

Program Description

The Flux Thimble Tube Inspection is a condition monitoring program used to inspect for thinning of the flux thimble tube wall, which provides a path for the incore neutron flux monitoring system detectors and forms part of the reactor coolant system (RCS) pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel where flow-induced fretting causes wear at discontinuities in the path from the reactor vessel instrument nozzle to the fuel assembly instrument guide tube. A nondestructive examination methodology, such as eddy current testing (ECT) or other applicant-justified and U.S. Nuclear Regulatory Commission (NRC)-accepted inspection method, is used to monitor for wear of the flux thimble tubes. This program implements the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," as described below.

Evaluation and Technical Basis

331. ***Scope of Program:*** The flux thimble tube inspection encompasses all of the flux thimble tubes that form part of the RCS pressure boundary. The instrument guide tubes are not in the scope of this program. Within scope are the licensee responses to Bulletin 88-09, as accepted by the staff in its closure letters on the bulletin, and any amendments to the licensee responses as approved by the staff.

332. ***Preventive Actions:*** The program consists of inspection and evaluation and provides no guidance on preventive actions.

333. ***Parameters Monitored/Inspected:*** Flux thimble tube wall thickness is monitored to detect loss of material from the flux thimble tubes during the period of extended operation.

334. ***Detection of Aging Effects:*** An inspection methodology (such as ECT) that has been demonstrated to be capable of adequately detecting wear of the flux thimble tubes is used to detect loss of material during the period of extended operation. Justification for methods other than ECT should be provided unless use of the alternative method has been previously accepted by the NRC.

    Examination frequency is based upon actual plant-specific wear data and wear predictions that have been technically justified as providing conservative estimates of flux thimble tube wear. The interval between inspections is established such that no flux thimble tube is predicted to incur wear that exceeds the established acceptance criteria before the next inspection. The examination frequency may be adjusted based on plant-specific wear projections. Re-baselining of the examination frequency should be justified using plant-specific wear-rate data unless prior plant-specific NRC acceptance for the re-baselining is received outside the license renewal process. If design changes are made to use more wear-resistant thimble tube materials (e.g., chrome-plated stainless steel), sufficient inspections are conducted at an adequate inspection frequency, as described above, for the new materials.

335. ***Monitoring and Trending:*** Flux thimble tube wall thickness measurements are trended and wear rates are calculated based on plant-specific data. Wall thickness is projected using plant-specific data and a methodology that includes sufficient conservatism to ensure that

wall thickness acceptance criteria continue to be met during plant operation between scheduled inspections.

336. ***Acceptance Criteria:*** Appropriate acceptance criteria such as percent through-wall wear are established, and inspection results are evaluated and compared with the acceptance criteria. The acceptance criteria are technically justified to provide an adequate margin of safety to ensure that the integrity of the reactor coolant system pressure boundary is maintained. The acceptance criteria include allowances for factors such as instrument uncertainty, uncertainties in wear scar geometry, and other potential inaccuracies, as applicable, to the inspection methodology chosen for use in the program. Acceptance criteria different from those previously documented in the applicant's response to Bulletin 88-09 and amendments thereto, as accepted by the NRC, should be justified.

337. ***Corrective Actions:*** Flux thimble tubes with wall thickness which do not meet the established acceptance criteria are isolated, capped, plugged, withdrawn, replaced, or otherwise removed from service in a manner that ensures the integrity of the reactor coolant system pressure boundary is maintained. Analyses may allow repositioning of flux thimble tubes that are approaching the acceptance criteria limit. Repositioning of a tube exposes a different portion of the tube to the discontinuity that is causing the wear.

Flux thimble tubes that cannot be inspected over the tube length, that are subject to wear due to restriction or other defects, and that cannot be shown by analysis to be satisfactory for continued service are removed from service to ensure the integrity of the reactor coolant system pressure boundary.

The site corrective actions program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

338. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

339. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

340. ***Operating Experience:*** In IE Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," the NRC requested that licensees implement a flux thimble tube inspection program due to several instances of leaks and due to licensees identifying wear. Utilities established inspection programs in accordance with IE Bulletin 88-09, which have shown excellent results in identifying and managing wear of flux thimble tubes.

As discussed in IE Bulletin 88-09, the amount of vibration the thimble tubes experience is determined by many plant-specific factors. Therefore, the only effective method for determining thimble tube integrity is through inspections which are adjusted to account for plant-specific wear patterns and history.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC IE Bulletin 88-09, *Thimble Tube Thinning in Westinghouse Reactors*, July 26, 1988.

NRC Information Notice No. 87-44, *Thimble Tube Thinning in Westinghouse Reactors*, September 16, 1987.

NRC Information Notice No. 87-44, Supplement 1, *Thimble Tube Thinning in Westinghouse Reactors*, March 28, 1988.

XI.M38 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

Program Description

The program consists of inspections of the internal surfaces of metallic piping, piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, condensation, and any water system other than open- and closed-cycle cooling and fire water. These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to ensure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. For certain materials, such as polymers, physical manipulation (such as pressurization) to detect hardening or loss of strength should be used to augment the visual examinations conducted under this program. If visual inspection of internal surfaces is not possible, then the applicant needs to provide a plant-specific program.

This program is not intended for piping and ducts where failures have occurred from loss of material from corrosion. [Note - Recent operating experience indicates that loss of material due to microbiologically influenced corrosion may be occurring in some water systems in spite of the programs associated with this aging management program. The staff is considering whether additional actions should be taken by plants which have experienced loss of material in raw water systems.]

Evaluation and Technical Basis

341. ***Scope of Program:*** For metallic components, the program calls for the visual inspection of the internal surface of in-scope components that are not included in other AMPs for loss of materials. For metallic components with polymeric liners or for polymeric and elastomeric components, the program includes visual inspections of the internal polymer surfaces when coupled with additional augmented techniques such as manipulation or pressurization. This program also includes metallic piping (including steel, stainless steel, galvanized, nickel, and copper alloys) with or without polymeric linings, piping elements, ducting, and components in an internal environment. The program also calls for visual inspection and monitors the internal surfaces of polymeric and elastomeric components in mechanical systems within the scope of license renewal and subject to aging management review for hardening and loss of strength, cracking, and for loss of material due to wear. The program manages the effects of aging of polymer materials in all environments to which these materials are exposed. Inspections are performed when the internal surfaces are accessible during the performance of periodic surveillances or during maintenance activities or scheduled outages.

342. ***Preventive Actions:*** This program is a condition monitoring program to detect signs of degradation and does not provide guidance for prevention.

343. ***Parameters Monitored/Inspected:*** Parameters monitored or inspected include visible evidence of loss of material in metallic components.

This program manages loss of material and possible change in material properties. The program monitors for evidence of surface discontinuities. For changes in material properties, the visual examinations are supplemented so changes in the properties are readily observable.

Examples of inspection parameters for metallic components include:

- corrosion and material parameters wastage (loss of material)
- leakage from or onto internal surfaces (loss of material)
- worn, flaking, or oxide-coated surfaces (loss of material)

Examples of inspection parameters for polymers are:

- surface cracking, crazing, scuffing, and dimensional change (e.g., “ballooning” and “necking”)
- discoloration
- exposure of internal reinforcement for reinforced elastomers
- hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate to manipulation

344. ***Detection of Aging Effects:*** Visual inspections (VT-3 or equivalent) of internal surfaces of metallic and rigid polymeric components are performed during each maintenance or surveillance activity. These inspections provide for the detection of aging effects prior to the loss of component function. Visual inspection (VT-3 or equivalent) of flexible polymeric components is performed whenever the component surface is accessible. Visual inspection can provide indirect indicators of the presence of surface cracking, crazing, and discoloration. For elastomers with internal reinforcement, visual inspection can detect the exposure of reinforcing fibers, mesh, or underlying metal. Visual inspections should be performed on nearly 100 percent of readily accessible components or include 100 percent on a rotating basis. Visual inspection provides direct indicators of loss of material due to wear, including dimensional change, scuffing, and for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal.

Manual or physical manipulation of flexible polymeric components should be used to augment visual inspection, where appropriate, to assess loss of material or strength. The sample size for manipulation should be at least 10 percent of available surface area, including visually identified suspect areas. For flexible polymeric materials, hardening, loss of strength, or loss of material due to wear is expected to be detectable prior to any loss of intended function.

345. ***Monitoring and Trending:*** The inspection of internal surfaces in miscellaneous piping and ducting components program uses standardized monitoring and trending activities to track degradation. Deficiencies are documented using approved processes and procedures such that results can be trended. However, the program does not include formal trending. Inspections are performed at frequencies identified in Element 4, “Detection of Aging Effects.”

346. ***Acceptance Criteria:*** For each component/aging effect combination, the acceptance criteria are defined to ensure that the need for corrective actions are identified before loss of intended functions. For metallic surfaces, any indications of relevant degradation detected are evaluated. For stainless steel surfaces, a clean shiny surface is expected. The appearance of discoloration may indicate the loss of material on the stainless steel surface. For aluminum and copper alloys exposed to marine or industrial environments, any indications of relevant degradation detected are evaluated. Any abnormal surface condition may be an indication of an aging effect for metals.

For flexible polymers, a uniform surface texture and uniform color with no unanticipated dimensional change is expected. Any abnormal surface condition may be an indication of an aging effect for metals and for polymers. For flexible materials to be considered acceptable, the inspection results should indicate that the flexible polymer material is in “as new” condition (e.g., the hardness, flexibility, physical dimensions, and color of the material are unchanged from when the material was new). Cracks should be absent within the material. For rigid polymers, surface changes affecting performance, such as erosion, cracking, crazing, checking, and chalks, are subject to further investigation.

Acceptance criteria include design standards, procedural requirements, current licensing basis, industry codes or standards, and engineering evaluation.

347. ***Corrective Actions:*** The site corrective actions program, quality assurance procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

348. ***Confirmation Process:*** As discussed in the GALL Report, the staff finds the requirements 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

349. ***Administrative Controls:*** As discussed in the GALL Report, the staff finds the requirements 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

350. Operating Experience: Inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant components reliability programs. These activities have proven effective in maintaining the material condition of plant systems, structures, and components.

The elements that comprise these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. However, because the inspection frequency is plant-specific and depends on the plant operating experience, the applicant’s plant-specific operating experience or applicable generic operating experience is further evaluated for the extended period of operation. The applicant evaluates recent operating experience and provides objective evidence to support the conclusion that the effects of aging are adequately managed.

This program is not intended for piping and ducts where failures have occurred from loss of material from corrosion. [Note - Recent operating experience indicates that loss of material due to microbiologically influenced corrosion may be occurring in some water systems in spite of the programs associated this aging management program. The staff is considering whether additional actions should be taken by plants which have experienced loss of material in raw water systems.]

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

INPO Good Practice TS-413, *Use of System Engineers*, INPO 85-033, May 18, 1988.

EPRI Technical Report 1007933, *Aging Assessment Field Guide*, December 2003.

EPRI Technical Report 1009743, *Aging Identification and Assessment Checklist*, August 27, 2004.

XI.M39 LUBRICATING OIL ANALYSIS PROGRAM

Program Description

The purpose of the Lubricating Oil Analysis Program is to ensure the oil environment in the mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of the program. The Lubricating Oil Analysis Program maintains oil systems contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction of heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of water or particulates may also be indicative of inleakage and corrosion product buildup.

Evaluation and Technical Basis

351. ***Scope of Program:*** The program manages aging effects of loss of material due to corrosion or wear, cracking due to stress corrosion cracking (SCC), or reduction of heat transfer due to fouling. Components within the scope of the program include piping, piping components, and piping elements; heat exchanger tubes; reactor coolant pump elements; and any other plant components subject to aging management review that are exposed to an environment of lubricating oil.

352. ***Preventive Actions:*** The Lubricating Oil Analysis Program maintains oil system contaminants (primarily water and particulates) within acceptable limits.

353. ***Parameters Monitored/Inspected:*** This program performs a check for water and a particle count to detect evidence of contamination by moisture or excessive corrosion.

354. ***Detection of Aging Effects:*** Moisture or corrosion products increase the potential for, or may be indicative of, loss of material due to corrosion, cracking due to SCC, or reduction of heat transfer due to fouling. The program performs periodic sampling and testing of lubricating oil for moisture and corrosion particles in accordance with industry standards. The program performs sampling and testing of the old oil following periodic oil changes or on a schedule consistent with equipment manufacturer’s recommendations or industry standards (e.g., American Society for Testing of Materials [ASTM] D 6224-02) when oil changes are not periodically performed. Plant-specific operating experience may also be considered in determining the schedule for periodic sampling and testing.

Prior to the period of extended operation, a one-time inspection of selected components exposed to lubricating oil is performed to verify the effectiveness of the Lubricating Oil Analysis Program in preventing age-related component degradation.

355. ***Monitoring and Trending:*** Oil analysis results are reviewed to determine if alert levels or limits have been reached or exceeded. This review also checks for unusual trends.

356. ***Acceptance Criteria:*** Water and particle concentration should not exceed limits based on equipment manufacturer’s recommendations or industry standards. Phase-separated water in any amount is not acceptable.

357. ***Corrective Actions:*** Pursuant to 10 CFR Part 50, Appendix B, specific corrective actions are implemented in accordance with the plant quality assurance (QA) program. For example, if a limit is reached or exceeded, actions to address the condition are taken. These may include increased monitoring, corrective maintenance, further laboratory analysis, and engineering evaluation. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

358. ***Confirmation Process:*** Site QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

359. ***Administrative Controls:*** The administrative controls for this program provide for a formal review and approval of corrective actions. The administrative controls for this program are implemented through the site's QA program in accordance with the requirements of 10 CFR Part 50, Appendix B.

360. ***Operating Experience:*** The operating experience at some plants has identified (a) water in the lubricating oil and (b) particulate contamination. However, no instances of component failures attributed to lubricating oil contamination have been identified.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

ASTM D 6224-02, *Standard Practice for In-Service Monitoring of Lubricating Oil for Auxiliary Power Plant Equipment*, American Society of Testing Materials, West Conshohocken, PA, 2002.

XI.S1 ASME SECTION XI, SUBSECTION IWE

Program Description

10 CFR 50.55a imposes the inservice inspection (ISI) requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE, for steel containments (Class MC) and steel liners for concrete containments (Class CC). The full scope of IWE includes steel containment shells and their integral attachments, steel liners for concrete containments and their integral attachments, containment hatches and airlocks and moisture barriers, and pressure-retaining bolting. This evaluation covers the 2004 edition[23], as approved in 10 CFR 50.55a. ASME Code, Section XI, Subsection IWE, and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of steel containments, steel liners of concrete containments, and other containment components for license renewal.

The primary ISI method specified in IWE is visual examination (general visual, VT-3, VT-1). Limited volumetric examination (ultrasonic thickness measurement) and surface examination (e.g., liquid penetrant) may also be necessary in some instances to detect aging effects. IWE specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The program attributes are augmented to incorporate aging management activities, recommended in the Final Interim Staff Guidance LR-ISG-2006-01, needed to address the potential loss of material due to corrosion in the inaccessible areas of the boiling water reactor (BWR) Mark I steel containment. The attributes also are augmented to require surface examination for detection of cracking described in NRC Information Notice (IN) 92-20 and address recommendations delineated in NUREG-1339 and industry recommendations delineated in the Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 for structural bolting.

Evaluation and Technical Basis

361. ***Scope of Program:*** The scope of this program addresses the components of steel containments and steel liners of concrete containments specified in Subsection IWE-1000 as augmented by LR-ISG-2006-01. The components within the scope of Subsection IWE are Class MC pressure-retaining components (steel containments) and their integral attachments, metallic shell and penetration liners of Class CC containments and their integral attachments, containment moisture barriers, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal. The concrete portions of containments are inspected in accordance with Subsection IWL.

Subsection IWE exempts the following from examination:

(a) Components that are outside the boundaries of the containment as defined in the plant-specific design specification;

(b) Embedded or inaccessible portions of containment components that met the requirements of the original construction code of record;

[23] Refer to the GALL Report, Volume 2,Chapter I, for applicability of other editions of ASME Code, Section XI.

(c) Components that become embedded or inaccessible as a result of containment structure (i.e., steel containments [Class MC] and steel liners for concrete containments [Class CC]) repair or replacement, provided IWE-1232 and IWE-5220 are met; and

(d) Piping, pumps, and valves that are part of the containment system or that penetrate or are attached to the containment vessel (governed by IWB or IWC).

362. ***Preventive Action:*** The ASME Section XI, Subsection IWE, is a condition monitoring program. The program is augmented to include preventive actions that ensure moisture levels associated with an accelerated corrosion rate do not exist in the exterior portion of the BWR Mark I steel containment drywell shell. The actions consist of ensuring that the sand pocket area drains and/or the refueling seal drains are clear. The program is also augmented to require that the selection of bolting material installation torque or tension and the use of lubricants and sealants are in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of structural bolting.

363. ***Parameters Monitored or Inspected:***Table IWE-2500-1 references the applicable section in IWE-2300 and IWE-3500 that identify the parameters examined or monitored. Non-coated surfaces are examined for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents, and other signs of surface irregularities. Painted or coated surfaces are examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis are monitored for cracking. The moisture barriers are examined for wear, damage, erosion, tear, surface cracks, or other defects that permit intrusion of moisture against inaccessible areas of the pressure retaining surfaces of the metal containment shell or liner. Pressure-retaining bolting is examined for loosening and material conditions that cause the bolted connection to affect either containment leak-tight or structural integrity.

As recommended in LR-ISG-2006-01, license renewal applicants with BWR Mark I containments should monitor the sand pocket area drains and/or the refueling seal drains for water leakage. The licensees should ensure the drains are clear to prevent moisture levels associated with accelerated corrosion rates do not exist in the exterior portion of the drywell shell.

364. ***Detection of Aging Effects:*** The examination methods, frequency, and scope of examination specified in 10 CFR 50.55a and Subsection IWE ensure that aging effects are detected before they compromise the design-basis requirements. IWE-2500-1 and the requirements of 10 CFR 50.55a provide information regarding the examination categories, parts examined, and examination methods to be used to detect aging.

As indicated in IWE-2400, inservice examinations and pressure tests are performed in accordance with one of two inspection programs, A or B, on a specified schedule. Under Inspection Program A, there are four inspection intervals (at 3, 10, 23, and 40 years) for which 100 percent of the required examinations must be completed. Within each interval, there are various inspection periods for which a certain percentage of the examinations are to be performed to reach 100 percent at the end of that interval.

After 40 years of operation, any future examinations are performed in accordance with Inspection Program B. Under Inspection Program B, starting with the time the plant is placed into service, there is an initial inspection interval of 10 years and successive inspection intervals of 10 years each, during which 100 percent of the required examinations are to be completed. An expedited examination of containment is required by 10 CFR 50.55a, in which an inservice (baseline) examination specified for the first period of the first inspection interval for containment was to be performed by September 9, 2001. Thereafter, subsequent examinations are performed every 10 years from the baseline examination. Regarding the extent of examination, all accessible surfaces receive a visual examination as specified in IWE-2500-1 and the requirements of 10 CFR 50.55a. The acceptability of inaccessible areas of the BWR Mark I steel containment drywell is evaluated when conditions exist in the adjacent accessible areas that could indicate the presence of or could result in degradation to such inaccessible areas. IWE-1240 requires augmented examinations (Examination Category E-C) of containment surface areas subject to degradation. A VT-1 visual examination is performed for areas accessible from both sides, and volumetric (ultrasonic thickness measurement) examination is performed for areas accessible from only one side.

The requirements of ASME Section XI, Subsection IWE and 10 CFR 50.55a are augmented to require surface examination, in addition to visual examination, to detect cracking in stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis.

365. ***Monitoring and Trending:*** With the exception of inaccessible areas, all surfaces are monitored by virtue of the examination requirements on a scheduled basis. IWE-2420 specifies that:

(a) The sequence of component examinations established during the first inspection interval shall be repeated.

(b) When examination results require evaluation of flaws or areas of degradation in accordance with IWE-3000, and component is acceptable for continued service, the areas containing such flaws or areas of degradation shall be reexamined during the next inspection period listed in the schedule of the inspection program of IWE-2411 or IWE-2412, in accordance with Table IWE-2500-1, Examination Category E-C.

(c) When the reexaminations required by IWE-2420(b) reveal that the flaws or areas of degradation remain essentially unchanged for the next inspection period, these areas no longer require augmented examination in accordance with Table IWE-2500-1 and the regular inspection schedule is continued.

Applicants for license renewal for plants with BWR Mark I containment should augment IWE monitoring and trending requirements to address inaccessible areas of the drywell. The applicant should consider the following recommended actions based on plant-specific operating experience.

(a) Develop a corrosion rate that can be inferred from past ultrasonic testing (UT) examinations or establish a corrosion rate using representative samples in similar operating conditions, materials, and environments. If degradation has occurred, provide a technical basis using the developed or established corrosion rate to demonstrate that the drywell shell will have sufficient wall thickness to perform its intended function through the period of extended operation.

(b) Demonstrate that UT measurements performed in response to U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 87-05 did not show degradation inconsistent with the developed or established corrosion rate.

366. ***Acceptance Criteria:*** IWE-3000 provides acceptance standards for components of steel containments and liners of concrete containments. Table IWE-3410-1 presents criteria to evaluate the acceptability of the containment components for service following the preservice examination and each inservice examination. This table specifies the acceptance standard for each examination category. Most of the acceptance standards rely on visual examinations. Areas that are suspect require an engineering evaluation or require correction by repair or replacement. For some examinations, such as augmented examinations, numerical values are specified for the acceptance standards. For the containment steel shell or liner, material loss locally exceeding 10 percent of the nominal containment wall thickness or material loss that is projected to locally exceed 10 percent of the nominal containment wall thickness before the next examination are documented. Such areas are corrected by repair or replacement in accordance with IWE-3122 or accepted by engineering evaluation. Cracking of stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis is corrected by repair or replacement or accepted by engineering evaluation.

367. ***Corrective Actions:*** Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in IWE-3500 are acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment. Components that do not meet the acceptance standards are subject to additional examination requirements, and the components are repaired or replaced to the extent necessary to meet the acceptance standards of IWE-3000. For repair of components within the scope of Subsection IWE, IWE-3124 states that repairs and reexaminations are to comply with IWA-4000. IWA-4000 provides repair specifications for pressure retaining components, including metal containments and metallic liners of concrete containments. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

If moisture has been detected or suspected in the inaccessible area on the exterior of the Mark I containment drywell shell or the source moisture cannot be determined subsequent to root cause analysis then:

(a) Include in the scope of license renewal any components that are identified as a source of moisture, if applicable, such as the refueling seal or cracks in the stainless liners of the refueling cavity pools walls, and perform aging management review.

(b) Identify surfaces requiring examination by implementing augmented inspections for the period of extended operation in accordance with Subsection IWE-1240, as identified in Table IWE-2500-1, Examination Category E-C.

(c) Use examination methods that are in accordance with Subsection IWE-2500.

(d) Demonstrate, through use of augmented inspections performed in accordance with Subsection IWE, that corrosion is not occurring or that corrosion is progressing so slowly that the age-related degradation will not jeopardize the intended function of the drywell shell through the period of extended operation.

368. ***Confirmation Process:*** When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. If the evaluation determines that repair or replacement is necessary, Subsection IWE specifies confirmation that appropriate corrective actions have been completed and are effective. Subsection IWE states that repairs and reexaminations are to comply with the requirements of IWA-4000. Reexaminations are conducted in accordance with the requirements of IWA-2200, and the recorded results are to demonstrate that the repair meets the acceptance standards set forth in IWE-3500. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

369. ***Administrative Controls:*** IWA-6000 provides specifications for the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address administrative controls.

370. ***Operating Experience:*** ASME Section XI, Subsection IWE, was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of steel components of containment was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the NRC. NRC Information Notice (IN) 86-99, IN 88-82, IN 89-79, IN 2004-09, and NUREG-1522 described occurrences of corrosion in steel containment shells. NRC GL 87-05 addressed the potential for corrosion of BWR Mark I steel drywells in the “sand pocket region.” NRC IN 97-10 identified specific locations where concrete containments are susceptible to liner plate corrosion; IN 92-20 described an instance of containment bellows cracking, resulting in loss of leak tightness. More recently, IN 2006-01 described a through-wall cracking and its probable cause in the torus of a BWR Mark I containment. The cracking was identified by the licensee in the heat-affected zone at the high pressure cooling injection (HPCI) turbine exhaust pipe torus penetration. The licensee concluded that the cracking was most likely initiated by cyclic loading due to condensation oscillation during HPCI operation. These condensation oscillations induced on the torus shell may have been excessive due to a lack of an HPCI turbine exhaust pipe sparger that many licensees have installed. Other operating experience indicates that foreign objects embedded in concrete have caused through-wall corrosion of the liner plate at a few plants with reinforced concrete containments. The program is to consider the liner plate and containment shell corrosion and cracking concerns described in these generic communications. Implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, augmented to consider operating experience, and as recommended in LR-ISG-2006-01, is a necessary element of aging management for steel components of steel and concrete containments through the period of extended operation.

Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, stress corrosion cracking (SCC), and fatigue loading (NRC IE Bulletin 82-02, NRC GL 91-17). SCC has occurred in high strength bolts used for nuclear steam supply system component supports (EPRI NP-5769). The augmented ASME Section XI, Subsection IWE, incorporating recommendations documented in EPRI NP-5769 and TR-104213, is necessary to ensure containment bolting integrity.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2008.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWA, *General Requirements,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWB, *Requirements for Class 1 Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWC, *Requirements for Class 2 Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, April 1988.

EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel*, Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners, Electric Power Research Institute, 1990.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric Power Research Institute, December 1995.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

NRC Generic Letter 87-05, *Request for Additional Information Assessment of Licensee Measures to Mitigate and/or Identify Potential Degradation of Mark I Drywells,* U.S. Nuclear Regulatory Commission, March 12, 1987.

NRC Generic Letter 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC Information Notice 86-99, *Degradation of Steel Containments,* U.S. Nuclear Regulatory Commission, December 8, 1986 and Supplement 1, February 14, 1991.

NRC Information Notice 88-82, *Torus Shells with Corrosion and Degraded Coatings in BWR Containments,* U.S. Nuclear Regulatory Commission, October 14, 1988 and Supplement 1, May 2, 1989.

NRC Information Notice 89-79, *Degraded Coatings and Corrosion of Steel Containment Vessels,* U.S. Nuclear Regulatory Commission, December 1, 1989 and Supplement 1, June 29, 1989.

NRC Information Notice 92-20, *Inadequate Local Leak Rate Testing,* U.S. Nuclear Regulatory Commission, March 3, 1992.

NRC Information Notice 97-10, *Liner Plate Corrosion in Concrete Containment,* U.S. Nuclear Regulatory Commission, March 13, 1997.

NRC Information Notice 2004-09, *Corrosion of Steel Containment and Containment Liner*, U.S. Nuclear Regulatory Commission, April 27, 2004.

NRC Information Notice 2006-01, *Torus Cracking in a BWR Mark I Containment*, U.S. Nuclear Regulatory Commission, January 12, 2006.

NRC Morning Report, *Failure of Safety/Relief Valve Tee-Quencher Support Bolts*, March 14, 2005. (ADAMS Accession Number ML050730347)

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

NUREG-1552, *Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures*, June 1995.

Staff Position and Rationale for the Final License Renewal Interim Staff Guidance LR-ISG-2006-01, *Plant-Specific Aging Management Program for Inaccessible Areas of Boiling Water Reactor (BWR) Mark I Steel Containments Drywell Shell,* Nuclear Regulatory Commission, November 16, 2006.

XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL, for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. This evaluation covers the 2004[24] edition of the Code, as approved in 10 CFR 50.55a. ASME Code, Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of containment reinforced concrete and unbonded post-tensioning systems for license renewal.

The primary inspection method specified in IWL-2500 is visual examination supplemented by testing. For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. The quantity of free water contained in the anchorage end cap and any free water which drains from tendons during the examination is documented. Samples of free water are analyzed for pH. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The 2004 edition of the Code specifies augmented examination requirements following post-tensioning system repair/replacement activities. The post-tensioning system repair/replacement activities are to be in accordance with these requirements.

Evaluation and Technical Basis

371. ***Scope of Program:*** Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete; unbonded post-tensioning systems of Class CC containments, as defined by CC-1000; and testing of the tendon corrosion protection medium and free water. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill or obstructed by adjacent structures or other components).

10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL but are included within the scope of Subsection IWE.

372. ***Preventive Action:*** ASME Section XI, Subsection IWL is a condition monitoring program. However, the program includes actions to prevent or minimize corrosion of the prestressing tendons by maintaining corrosion protection medium chemistry within acceptable limits specified in IWL.

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[24] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

373. ***Parameters Monitored or Inspected:*** Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all accessible concrete surfaces and Category L-B for concrete surfaces surrounding anchorages of tendons selected for testing in accordance with IWL-2521. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R and ACI 349.3R[25]. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. The number of tendons are selected and examined in accordance with Table IWL-2521-1. Additional augmented examination requirements for post-tensioning system repair/replacement activities are to be in accordance with IWL-2521-2. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations. Free water samples are analyzed for pH.

374. ***Detection of Aging Effects:*** The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at 1, 3, and 5 years following the structural integrity test. Thereafter, inspections are performed at 5-year intervals.

For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Regarding detection methods for aging effects, all accessible concrete surfaces receive General Visual examination. Selected areas, such as those that indicate suspect conditions and concrete surface areas surrounding tendon anchorages (Category L-B), receive a more rigorous Detailed Visual examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments. Examination of corrosion protection medium and free water are tested for each examined tendon as specified in Table IWL-2525-1.

375. ***Monitoring and Trending:*** Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. Corrosion protection medium chemistry and free water pH are monitored for each examined tendon. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.

376. ***Acceptance Criteria:*** IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R and ACI 349.3R for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the Responsible Engineer.

The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. Free water in the tendon anchorage areas is not acceptable as specified in IWL-3221.3. If free water is found, the recommendations in Table IWL-2525-1 are followed. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation.

377. ***Corrective Actions:*** Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300, "Evaluation," and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

378. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

379. ***Administrative Controls:*** IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

380. ***Operating Experience:*** ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). NUREG-1522 described instances of cracked, spalled, and degraded concrete for reinforced and prestressed concrete containments. The NUREG also described cracked anchor heads for the prestressing tendons at three prestressed concrete containments. Recently, NRC Information Notice 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in these generic communications. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is a necessary element of aging management for concrete containments through the period of extended operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2008.

ACI Standard 201.1R, *Guide for Making a Condition Survey of Concrete in Service,* American Concrete Institute.

ACI Standard 349.3R, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWA, *General Requirements,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants,* 2004 edition, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 99-10, Revision 1, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment,* U.S. Nuclear Regulatory Commission, October 7, 1999.

NRC Regulatory Guide 1.35.1, *Determining Prestressing Forces for Inspection of Prestressed Concrete Containments*, U.S. Nuclear Regulatory Commission, July 1990.

NUREG-1522, *Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures,* June 1995.

XI.S3 ASME SECTION XI, SUBSECTION IWF

Program Description

10 CFR 50.55a imposes the inservice inspection requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, for Class 1, 2, 3, and metal containment (MC) piping and components and their associated supports. Inservice inspection of supports for ASME piping and components is addressed in Section XI, Subsection IWF. This evaluation covers the 2004 edition[1] of the ASME Code as approved in 10 CFR 50.55a. ASME Code, Section XI, Subsection IWF, constitutes an existing mandated program applicable to managing aging of ASME Class 1, 2, 3, and MC component supports for license renewal.

The IWF scope of inspection for supports is based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1). The sample size decreases for the less critical supports (ASME Class 2 and 3). Discovery of support deficiencies during regularly scheduled inspections triggers an increase of the inspection scope in order to ensure that the full extent of deficiencies is identified. The primary inspection method employed is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. IWF specifies acceptance criteria and corrective actions. Supports requiring corrective actions are re-examined during the next inspection period.

The requirements of subsection IWF are augmented to include monitoring of high strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) for cracking. The program is augmented to incorporate recommendations delineated in NUREG-1339 and industry recommendations delineated in the Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 for structural bolting. These recommendations emphasize proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload and cracking of high strength bolting.

Evaluation and Technical Basis

381. ***Scope of Program:*** This program addresses supports for ASME Class 1, 2, and 3 piping and components supports that are not exempt from examination in accordance with IWF -1230 and MC supports. The scope of the program includes support members, structural bolting, high strength structural bolting, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements.

382. Preventive Action: Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting. Operating experience and laboratory examinations show that the use of molybdenum disulfide (MoS_2) as a lubricant is a potential contributor to stress corrosion cracking (SCC), especially when applied to high strength bolting. Thus, molybdenum disulfide and other lubricants containing sulfur should not be used. Preventive measures also include using bolting material that has an actual measured yield strength less than 150 ksi or 1,034 MPa. Structural bolting replacement and maintenance activities include

[1] Refer to the GALL Report, Volume 2, Chapter I, for applicability of other editions of ASME Code, Section XI.

appropriate preload and proper tightening (torque or tension) as recommended in EPRI documents, American Society for Testing of Materials (ASTM) standards, American Institute of Steel Construction (AISC) Specifications, as applicable.

383. ***Parameters Monitored or Inspected:*** The parameters monitored or inspected include corrosion; deformation; misalignment of supports; missing, detached, or loosened support items; improper clearances of guides and stops; and improper hot or cold settings of spring supports and constant load supports. Accessible areas of sliding surfaces are monitored for debris, dirt, or indications of excessive loss of material due to wear that could prevent or restrict sliding as intended in the design basis of the support. Elastomeric vibration isolation elements are monitored for cracking, loss of material, and hardening. Structural bolts are monitored for corrosion and loss of preload due to self loosening. High strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) should be monitored for SCC.

384. ***Detection of Aging Effects:*** The program requires that a sample of ASME Class 1, 2, and 3 component supports that are not exempt from examination and 100 percent of MC component supports be examined as specified in Table IWF-2500-1. The sample size examined for ASME Class 1, 2, and 3 component supports is as specified in Table IWF-2500-1. The extent, frequency, and examination methods are designed to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program can reveal loss of material due to corrosion and wear, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections. The VT-3 examination can also detect loss of material and cracking of elastomeric vibration isolation elements. VT-3 examination of elastomeric vibration isolation elements should be supplemented by feel to detect hardening if the vibration isolation function is suspect. IWF-3200 specifies that visual examinations that detect surface flaws which exceed acceptance criteria may be supplemented by either surface or volumetric examinations to determine the character of the flaw. For high strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch nominal diameter, volumetric examination comparable to that of ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 should be performed to detect cracking in addition to the VT-3 examination. This volumetric examination may be waived with adequate plant-specific justification.

385. ***Monitoring and Trending:*** The ASME Class 1, 2, 3, and MC component supports are examined periodically as specified in Table IWF-2500-1. As required by IWF-2420(a), the sequence of component support examinations established during the first inspection interval is repeated during each successive inspection interval, to the extent practical. Component supports whose examinations do not reveal unacceptable degradations are accepted for continued service. Verified changes of conditions from prior examination are recorded in accordance with IWA-6230. Component supports whose examinations reveal unacceptable conditions and are accepted for continued service by corrective measures or repair/replacement activity are reexamined during the next inspection period. When the reexamined component support no longer requires additional corrective measures during the next inspection period, the inspection schedule may revert to its regularly scheduled inspection. Examinations that reveal indications which exceed the acceptance standards and require corrective measures are extended to include additional examinations in accordance with IWF-2430.

386. ***Acceptance Criteria:*** The acceptance standards for visual examination are specified in IWF-3400. IWF-3410(a) identifies the following conditions as unacceptable:

(a) Deformations or structural degradations of fasteners, springs, clamps, or other support items;

(b) Missing, detached, or loosened support items, including bolts and nuts;

(c) Arc strikes, weld spatter, paint, scoring, roughness, or general corrosion on close tolerance machined or sliding surfaces;

(d) Improper hot or cold positions of spring supports and constant load supports;

(e) Misalignment of supports; and

(f) Improper clearances of guides and stops.

Other unacceptable conditions include,

(a) Loss of material due to corrosion or wear, which reduces the load bearing capacity of the component support;

(b) Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support;

(c) Cracked or sheared bolts, including high strength bolts, and anchors; and

(d) Loss of material, cracking, and hardening of elastomeric vibration isolation elements that could reduce the vibration isolation function.

The above conditions may be accepted provided the technical basis for their acceptance is documented.

387. ***Corrective Actions:*** Identification of unacceptable conditions triggers an expansion of the inspection scope, in accordance with IWF-2430, and reexamination of the supports requiring corrective actions during the next inspection period, in accordance with IWF-2420(b). In accordance with IWF-3122, supports containing unacceptable conditions are evaluated or tested or corrected before returning to service. Corrective actions are delineated in IWF-3122.2. IWF-3122.3 provides an alternative for evaluation or testing to substantiate structural integrity and/or functionality. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

388. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

389. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

390. ***Operating Experience:*** To date, IWF sampling inspections have been effective in managing aging effects for ASME Class 1, 2, 3, and MC supports. There is reasonable assurance that the Subsection IWF inspection program will be effective in managing the aging of the in-scope component supports through the period of extended operation.

Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC IE Bulletin 82-02, NRC Generic Letter 91-17). SCC has occurred in high strength bolts used for NSSS component supports (EPRI NP-5769). The augmented ASME Section XI, Subsection IWE, incorporating recommendations documented in EPRI NP-5769 and TR-104213, is necessary to ensure containment bolting integrity.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.55a, *Codes and Standards,* Office of the Federal Register, National Archives and Records Administration, 2008.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWB, *Requirements for Class 1 Components of Light-Water Cooled Power Plants,* 2004 edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWC, *Requirements for Class 2 Components of Light-Water Cooled Power Plants,* 2004 edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWD, *Requirements for Class 3 Components of Light-Water Cooled Power Plants,* 2004 edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,* 2004 edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* Subsection IWF, *Requirements for Class 1, 2, 3, and MC Component Supports of Light-Water Cooled Power Plants,* 2004 edition. The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel*, Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners, Electric Power Research Institute, 1990.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide*, Electric Power Research Institute, December 1995.

NRC Generic Letter 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

NRC Morning Report, *Failure of Safety/Relief Valve Tee-Quencher Support Bolts*, March 14, 2005. (ADAMS Accession Number ML050730347)

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

XI.S4 10 CFR PART 50, APPENDIX J

Program Description

As described in 10 CFR Part 50, Appendix J, containment leak rate tests are required to "assure that (a) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the technical specifications and (b) integrity of the containment structure is maintained during its service life."

Appendix J provides two options, Option A and Option B, either of which can be chosen to meet the requirements of a containment leakage rate test (LRT) program. Option A is prescriptive with all testing performed on specified, uniform periodic intervals. Option B is a performance-based approach. Some of the differences between these options are discussed below, and more detailed information for Option B is provided in the Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.163[1] and NEI 94-01 as approved by the NRC Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2.

Three types of tests are performed under either Option A or Option B. Type A tests are performed to determine the overall primary containment integrated leakage rate at the loss of coolant accident peak containment. Type B tests are intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Type C tests are intended to detect local leaks and to measure leakage across containment isolation valves installed in containment penetrations or lines penetrating containment. If Type C tests are not performed under this program, they could be included under a leakage testing program for systems containing the isolation valves.

Appendix J requires a general inspection of the accessible interior and exterior surfaces of the containment structure and components be performed prior to any Type A test. Inspections performed in accordance with the ASME Section XI, Subsection IWE (XI.S1) or ASME Section XI, Subsection IWL (XI.S2) program are an acceptable substitute. The purpose of the inspection is to uncover any evidence of structural deterioration that may affect the containment structural integrity or leak-tightness. If there is evidence of structural deterioration, the Type A test is not performed until corrective action is taken in accordance with the repair/replacement procedures.

Evaluation and Technical Basis

391. ***Scope of Program:*** The scope of the containment LRT program includes all containment boundary pressure-retaining components.

392. Preventive Action: The containment LRT program is a performance monitoring program that includes no preventive actions.

393. ***Parameters Monitored or Inspected:*** The parameters to be monitored are leakage rates through containment shells, containment liners, and associated welds, penetrations, fittings, and other access openings.

394. ***Detection of Aging Effects:*** A containment LRT program is effective in detecting leakage rate of the containment pressure boundary components, including seals and gaskets. While the calculation of leakage rates and satisfactory performance of containment leakage rate testing demonstrates the leak-tightness and structural integrity of the

[1] RG 1.163 Rev. 0 or the latest Revision.

containment, it does not by itself provide information that would indicate that aging degradation has initiated or that the capacity of the containment may have been reduced for other types of loads, such as seismic loading. This would be achieved with the additional implementation of an acceptable containment inservice inspection program as described in ASME Section XI, Subsection IWE (XI.S1) and ASME Section XI, Subsection IWL (XI.S2).

395. ***Monitoring and Trending:*** Because the LRT program is repeated throughout the operating license period, the entire pressure boundary is monitored over time. The frequency of these tests depends on which option (A or B) is selected. With Option A, testing is performed on a regular fixed time interval as defined in 10 CFR Part 50, Appendix J. In the case of Option B, the interval for testing may be adjusted on the basis of acceptable performance in meeting leakage limits in prior tests. Additional details for implementing Option B are provided in NRC RG 1.163 and NEI 94-01.

396. ***Acceptance Criteria:*** Acceptance criteria for leakage rates are defined in plant technical specifications. These acceptance criteria meet the requirements in 10 CFR Part 50, Appendix J, and are part of each plant's current licensing basis.

397. ***Corrective Actions:*** Corrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01. When leakage rates do not meet the acceptance criteria, an evaluation is performed to identify the cause of the unacceptable performance and appropriate corrective actions are taken. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

398. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

399. ***Administrative Controls:*** Results of the LRT program are documented as described in 10 CFR Part 50, Appendix J, to demonstrate that the acceptance criteria for leakage have been satisfied. The test results that exceed the performance criteria are assessed under 10 CFR 50.72 and 10 CFR 50.73. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

400. ***Operating Experience:*** To date, the 10 CFR Part 50, Appendix J, LRT program, in conjunction with the containment in-service inspection program, has been effective in preventing unacceptable leakage through the containment pressure boundary. Implementation of Option B for testing frequency is consistent with plant-specific operating experience.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR Part 50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.72, *Immediate Notification Requirements for Operating Nuclear Power Reactors,* Office of the Federal Register, National Archives and Records Administration, 1997.

10 CFR 50.73, *Licensee Event Report System,* Office of the Federal Register, National Archives and Records Administration, 1997.

NEI 94-01, Rev. 2-A, *Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50 Appendix J,* Nuclear Energy Institute, August 2007.

NRC Regulatory Guide 1.163, Rev. 0, *Performance-Based Containment Leak-Test Program,* U.S. Nuclear Regulatory Commission, September 1995.

Final Safety Evaluation for 'Nuclear Energy Institute (NEI) Topical Report (TR) 94-01, Revision 2, *Industry Guideline for Implementing Performance-Based Option of 10 CFR, Part 50, Appendix J,'* and 'Electric Power Research Institute (EPRI) Report No. 1009325, Revision 2, *Risk Impact Assessment of Extended Integrated Leak Rate Testing Intervals*, August 2007,' June 25, 2008.

XI.S5 MASONRY WALLS

Program Description

Nuclear Regulatory Commission (NRC) IE Bulletin (IEB) 80-11, "Masonry Wall Design," and NRC Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11," constitute an acceptable basis for a masonry wall aging management program (AMP). IEB 80-11 required (a) the identification of masonry walls in close proximity to or having attachments from safety-related systems or components and (b) the evaluation of design adequacy and construction practice. NRC IN 87-67 recommended plant-specific condition monitoring of masonry walls and administrative controls to ensure that the evaluation basis developed in response to NRC IEB 80-11 is not invalidated by (a) deterioration of the masonry walls (e.g., new cracks not considered in the reevaluation), (b) physical plant changes such as installation of new safety-related systems or components in close proximity to masonry walls, or (c) reclassification of systems or components from non-safety-related to safety-related, provided appropriate evaluation is performed to account for such occurrences.

Important elements in the evaluation of many masonry walls during the NRC IEB 80-11 program included (a) installation of steel edge supports to provide a sound technical basis for boundary conditions used in seismic analysis and (b) installation of steel bracing to ensure stability or containment of unreinforced masonry walls during a seismic event. Consequently, in addition to the development of cracks in the masonry walls, loss of function of the structural steel supports and bracing would also invalidate the evaluation basis. The steel edge supports and steel bracings are considered component supports and are monitored for aging effects under the Structures Monitoring program (XI.S6).

The program requires periodic visual inspection of masonry walls in the scope of license renewal to detect the aging effects of loss of material and cracking of masonry units and mortar. Identified aging effects that could impact masonry wall intended function or potentially invalidate its evaluation basis, established during the NRC IEB 80-11 program, are entered in the corrective process for further analysis, repair, or replacement.

Since the issuance of NRC IEB 80-11 and NRC IN 87-67, the NRC promulgated 10 CFR 50.65, the Maintenance Rule. Masonry walls may be inspected as part of the “Structures Monitoring Program” (XI.S6) conducted for the Maintenance Rule, provided the 10 attributes described below are incorporated in AMP XI.S6.

Evaluation and Technical Basis

401. ***Scope of Program:*** The scope includes all masonry walls identified as performing intended functions in accordance with 10 CFR 54.4.

402. ***Preventive Action:*** This is a condition monitoring program and no specific preventive actions are required.

403. ***Parameters Monitored or Inspected:*** The primary parameters monitored are loss of material and cracking of masonry walls that could impact the intended function or potentially invalidate its evaluation basis.

404. ***Detection of Aging Effects:*** Visual examination of the masonry walls by qualified inspection personnel is sufficient. The frequency of inspection is every 5 years, with provisions for more frequent inspections in areas where loss of material or cracking is observed to ensure there is no loss of intended function between inspections. Unreinforced masonry walls, which have not been contained by bracing, warrant the most frequent inspection because the development of cracks may invalidate the existing evaluation basis.

405. ***Monitoring and Trending:*** Trending is not required. Condition monitoring for evidence of cracking and loss of material is achieved by periodic examination. Degradation detected from monitoring is evaluated.

406. ***Acceptance Criteria:*** For each masonry wall, the extent of observed loss of material or cracking may not invalidate the evaluation basis or impact the wall's intended function. However, further evaluation is conducted if the extent of cracking and loss of material is sufficient to impact the intended function of the wall or invalidate its evaluation basis.

407. ***Corrective Actions:*** A corrective action option is to develop a new analysis or evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation). Other alternatives include repair or replacing the degraded wall. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

408. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

409. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

410. ***Operating Experience:*** Since 1980, masonry walls that perform an intended function have been systematically identified through licensee programs in response to NRC IEB 80-11, NRC Generic Letter 87-02, and 10 CFR 50.48. NRC IN 87-67 documented lessons learned from the NRC IEB 80-11 program and provided recommendations for administrative controls and periodic inspection to ensure that the evaluation basis for each safety-significant masonry wall is maintained. NUREG-1522 documents instances of observed cracks and other deterioration of masonry-wall joints at nuclear power plants. Whether conducted as a stand-alone program or as part of structures monitoring for management review, a masonry wall AMP that incorporates the recommendations delineated in NRC IN 87-67 should ensure that the intended functions of all masonry walls within the scope of license renewal are maintained for the period of extended operation.

References10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.48, *Fire Protection,* Office of the Federal Register, National Archives and Records Administration, 2009.

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, 2009.

10 CFR 54.4, *Scope*, Office of the Federal Register, National Archives and Records Administration, 2009.

NRC Generic Letter 87-02, *Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46,* U.S. Nuclear Regulatory Commission, February 19, 1987.

NRC IE Bulletin 80-11, *Masonry Wall Design,* U.S. Nuclear Regulatory Commission, May 8, 1980.

NRC Information Notice 87-67, *Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11*, U.S. Nuclear Regulatory Commission, December 31, 1987.

NRC Regulatory Guide 1.160, Rev. 2*, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1997.

NUMARC 93-01, Rev. 2, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Line-In/Line-Out Version),* Nuclear Energy Institute, April 1996.

NUREG-1522, *Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures,* June 1995.

XI.S6 STRUCTURES MONITORING

Program Description

Implementation of structures monitoring under 10 CFR 50.65 (the Maintenance Rule) is addressed in Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, Rev. 2, and NUMARC 93-01, Rev. 2. These two documents provide guidance for development of licensee-specific programs to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function. Many license renewal applicants have found it necessary to enhance their structures monitoring program to ensure that the aging effects of structures and components in the scope of 10 CFR Part 54.4 are adequately managed during the period of extended operation.

The structures monitoring program consists of periodic visual inspections by personnel qualified to monitor structures and components for applicable aging effects, such as those described in the American Concrete Institute Standards (ACI) 349.3R, ACI 201.1R, and Structural Engineering Institute/American Society of Civil Engineers Standard (SEI/ASCE) 11. Visual inspections should be supplemented with volumetric or surface examinations to detect stress corrosion cracking (SCC) in high strength (actual measured yield strength greater than or equal to 150 kilo-pound per square inch [ksi] or greater than or equal to 1,034 MPa) structural bolts greater than 1 inch in diameter. Identified aging effects are evaluated by qualified personnel using criteria derived from industry codes and standards contained in the plant current licensing bases, including ACI 349.3R, ACI 318, SEI/ASCE 11, and the American Institute of Steel Construction (AISC) specifications, as applicable.

The program includes preventive actions delineated in NUREG-1339 and in Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 to ensure structural bolting integrity. The program also should require periodic sampling and testing of ground water and the need to assess the impact of any changes in its chemistry on below grade concrete structures.

If protective coatings are relied upon to manage the effects of aging for any structures included in the scope of this aging management program (AMP), the structures monitoring program is to address protective coating monitoring and maintenance.

Evaluation and Technical Basis

411. ***Scope of Program:*** The scope of the program includes all structures, structural components, component supports, and structural commodities in the scope of license renewal that are not covered by other structural AMPs (i.e., AMP ASME Section XI, Subsection IWE (XI.S1); ASME Section XI, Subsection IWL (XI.S2); ASME Section XI, Subsection IWF (XI.S3); “Masonry Walls Program” (XI.S5); and NRC RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” (XI.S7). Examples of structures, structural components, and commodities in the scope of the program are concrete and steel structures, structural bolting, anchor bolts and embedments, component support members, pipe whip restraints and jet impingement shields, transmission towers, panels and other enclosures, racks, sliding surfaces, sump and pool liners, electrical cable trays and conduits, trash racks associated with water control structures, electrical duct banks, manholes, doors, penetration seals, and tube tracks. The applicant is to specify other structures or components that are in the scope of its structures monitoring program. The scope of this program includes periodic sampling and testing of ground water and may include inspection of masonry walls and water-control structures provided all the attributes of the “Masonry Wall Program” (XI.S5) and NRC RG 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants” (XI.S7) are incorporated in the attributes of this program.

412. ***Preventive Action:*** The structures monitoring program is a condition monitoring program. The program should include preventive actions delineated in NUREG-1339 and in EPRI NP-5769, NP-5067, and TR-104213 to ensure structural bolting integrity. These actions emphasize proper selection of bolting material, lubricants, and installation torque or tension to prevent or minimize loss of bolting preload and cracking of high strength bolting.

413. ***Parameters Monitored or Inspected:*** For each structure/aging effect combination, the specific parameters monitored or inspected depend on the particular structure, structural component, or commodity. Parameters monitored or inspected are commensurate with industry codes, standards, and guidelines and also consider industry and plant-specific operating experience. ACI 349.3R and ANSI/ASCE 11 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable).

For concrete structures, parameters monitored include loss of material, cracking, increase in porosity and permeability, loss of foundation strength, and reduction in concrete anchor capacity due to local concrete degradation. Steel structures and components are monitored for loss of material due to corrosion. Structural bolting is monitored for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload. High strength (actual measured yield strength ≥ 150 ksi or 1,034 MPa) structural bolts greater than 1 inch in diameter are monitored for SCC. Anchor bolts are monitored for loss of material, loose or missing nuts, and cracking of concrete around the anchor bolts. Accessible sliding surfaces are monitored for indication of significant loss of material due to wear or corrosion, debris, or dirt. Elastomeric vibration isolators and structural sealants are monitored for cracking, loss of material, and hardening. These parameters and other monitored parameters are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Ground water chemistry (pH, chlorides, and sulfates) are monitored periodically to assess its impact, if any, on below grade concrete structures. If necessary for managing settlement and erosion of porous concrete sub-foundations, the continued functionality of a site de-watering system is monitored. The plant-specific structures monitoring program contains sufficient detail on parameters monitored or inspected to conclude that this program attribute is satisfied.

414. ***Detection of Aging Effects:*** Structures are monitored under this program using periodic visual inspection of each structure/aging effect combination by a qualified inspector to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Visual inspection of high strength structural bolting greater than 1 inch in diameter is supplemented with volumetric or surface examinations to detect cracking. Visual inspection of elastomeric vibration isolation elements should be supplemented by feel to detect hardening if the vibration isolation function is suspect. The inspection frequency depends on safety significance and the condition of the structure as specified in NRC RG 1.160. However, all structures and ground water are monitored on a frequency not to exceed 5 years. The program includes provisions for more frequent inspections of structures and components categorized as (a)(1) in accordance with 10 CFR 50.65. Inspector qualifications should be consistent with industry guidelines and standards and guidelines for implementing the requirements of 10 CFR 50.65. Qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for license renewal.

The structures monitoring program addresses detection of aging affects for inaccessible, below-grade concrete structural elements. For plants with non-aggressive ground water/soil (pH > 5.5, chlorides < 500 ppm, or sulfates <1500 ppm), the program recommends: (a) evaluating the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below grade concrete, when excavated for any reason.

For plants with aggressive groundwater/soil (pH < 5.5, chlorides > 500 ppm, or sulfates > 1500 ppm) and/or where the concrete structural elements have experienced degradation, a plant-specific AMP accounting for the extent of the degradation experienced should be implemented to manage the concrete aging during the period of extended operation.

415. ***Monitoring and Trending:*** Regulatory Position 1.5, "Monitoring of Structures," in NRC RG 1.160, Rev. 2, provides an acceptable basis for meeting the attribute. A structure is monitored in accordance with 10 CFR 50.65(a)(2) provided there is no significant degradation of the structure. A structure is monitored in accordance with 10 CFR 50.65(a)(1) if the extent of degradation is such that the structure may not meet its design basis or, if allowed to continue uncorrected until the next normally scheduled assessment, may not meet its design basis.

416. ***Acceptance Criteria:*** The structures monitoring program calls for inspection results to be evaluated by qualified engineering personnel based on acceptance criteria selected for each structure/aging effect to ensure that the need for corrective actions are indentified before loss of intended functions. The criteria are derived from design bases codes and standards that include ACI 349, ACI 318, SEI/ASCE 11, or the AISC specifications, as applicable, and consider industry and plant operating experience. The criteria are directed at the identification and evaluation of degradation that may affect the ability of the structure or component to perform its intended function. Applicants who are not committed to ACI 349 and elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from ACI 349. Loose bolts and nuts and cracked high strength bolts are not acceptable unless accepted by engineering evaluation. Structural sealants are acceptable if the observed loss of material, cracking, and hardening will not result is loss of sealing. Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, or hardening that could lead to the reduction or loss of isolation function. Acceptance criteria for sliding surfaces are (a) no indications of excessive loss of material due to corrosion or wear and (b) no debris or dirt that could restrict or prevent sliding of the surfaces as required by design. The structures monitoring program is to contain sufficient detail on acceptance criteria to conclude that this program attribute is satisfied.

417. ***Corrective Actions:*** Evaluations are performed for any inspection results that do not satisfy established criteria. Corrective actions are initiated in accordance with the corrective action process if the evaluation results indicate there is a need for a repair or replacement. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

418. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

419. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

420. ***Operating Experience:*** Although many plants' structures monitoring programs have only recently been implemented, plant maintenance has been ongoing since plant operations were initiated. NUREG-1522 documents the results of a survey sponsored in 1992 by the Office of Nuclear Regulatory Research to obtain information on the types of distress in the concrete structures, the type of repairs performed, and the durability of the repairs. Licensees who responded to the survey reported cracking, scaling, and leaching of concrete structures. The degradations were attributed to drying shrinkage, freeze-thaw, and abrasion. The NUREG also describes the results of NRC staff inspections at six plants. The staff observed concrete degradations, corrosion of component support members and anchor bolts, cracks and other deterioration of masonry walls, and ground water leakage and seepage in underground structures. The observed and reported degradations were more severe at coastal plants than those observed in inland plants as a result of brackish and sea water. Previous license renewal applicants reported similar degradations and corrective actions taken through their structures monitoring program. There is reasonable assurance that implementation of the structures monitoring program described above will be effective in managing the aging of the in-scope structures and component supports through the period of extended operation.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.65, *Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 54.4, *Scope*, Office of the Federal Register, National Archives and Records Administration, 2009.

ACI Standard 201.1R, *Guide for Making a Condition Survey of Concrete in Service,* American Concrete Institute, 1992.

ACI Standard 318, *Building Code Requirements for Reinforced Concrete and Commentary,* American Concrete Institute.

ACI Standard 349.3R, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute.

AISC, *AISC Specification for Steel Buildings,* American Institute of Steel Construction, Inc., Chicago, IL.

ANSI/ASCE 11-90, 99, *Guideline for Structural Condition Assessment of Existing Buildings,* American Society of Civil Engineers.

EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel*, Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners, Electric Power Research Institute, 1990.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric Power Research Institute, December 1995.

NRC Regulatory Guide 1.127, Rev. 1, *Inspection of Water-Control Structures Associated with Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1978.

NRC Regulatory Guide 1.142, Rev. 2, *Safety-related Concrete Structures for Nuclear Power Plants (Other than Reactor Vessels and Containments)*, U.S. Nuclear Regulatory Commission, November 2001.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1997.

NUMARC 93-01, Rev. 2, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (Line-In/Line-Out Version),* Nuclear Energy Institute, April 1996.

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

NUREG-1522, *Assessment of Inservice Condition of Safety-Related Nuclear Power Plant Structures,* June 1995.

XI.S7 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

Program Description

Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.127, Revision 1, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," describes an acceptable basis for developing an inservice inspection and surveillance program for dams, slopes, canals, and other water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The NRC RG 1.127 program addresses age-related deterioration, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures. The NRC RG 1.127 program recognizes the importance of periodic monitoring and maintenance of water-control structures so that the consequences of age-related deterioration and degradation can be prevented or mitigated in a timely manner.

NRC RG 1.127 provides detailed guidance for the licensee's inspection program for water-control structures, including guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. NRC RG 1.127 delineates current NRC practice in evaluating inservice inspection programs for water-control structures.

For plants not committed to NRC RG 1.127, Revision 1, aging management of water-control structures may be included in the “Structures Monitoring Program” (XI.S6). Even if a plant is committed to NRC RG 1.127, Revision 1, aging management of certain structures and components may be included in the “Structures Monitoring Program” (XI.S6). However, details pertaining to water-control structures, as described herein, are incorporated in XI.S6 program attributes.

NRC RG 1.127 attributes evaluated below do not include inspection of dams. For dam inspection and maintenance, programs under the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC) or the U.S. Army Corps of Engineers, continued through the period of extended operation, are adequate for the purpose of aging management. For programs not falling under the regulatory jurisdiction of FERC or the U.S. Army Corps of Engineers, the staff evaluates the effectiveness of the aging management program (AMP) based on compatibility to the common practices of the FERC and Corps programs.

Evaluation and Technical Basis

421. ***Scope of Program:*** NRC RG 1.127 applies to water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The water-control structures included in the RG 1.127 program are concrete structures, embankment structures, spillway structures and outlet works, reservoirs, cooling water channels and canals, and intake and discharge structures. The scope of the program also includes structural steel and structural bolting associated with water-control structures, steel or wood piles and sheeting required for the stability of embankments and channel slopes, and miscellaneous steel, such as sluice gates and trash racks.

422. ***Preventive Action:*** NRC RG 1.127 is a condition monitoring program. This program is augmented to incorporate preventive measures recommended in NUREG-1339, Electric Power Research Institute (EPRI) TR-104213, and EPRI NP-5769 to ensure structural bolting integrity. The documents provide guidelines for selection of replacement bolting material, approved thread lubricants, and appropriate torque and preload to be used for installation of bolting.

423. ***Parameters Monitored or Inspected:*** NRC RG 1.127 identifies the parameters to be monitored and inspected for water-control structures. The parameters vary depending on the particular structure.

Parameters to be monitored and inspected for concrete structures are those described in American Concrete Institute (ACI) 201.1 and ACI-349-3R. These include cracking, movements (e.g., settlement, heaving, deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage.

Parameters to be monitored and inspected for earthen embankment structures include settlement, depressions, sink holes, slope stability (e.g., irregularities in alignment and variances from originally constructed slopes), seepage, proper functioning of drainage systems, and degradation of slope protection features.

Steel components are monitored for loss of material due to corrosion.

Parameters monitored for channels and canals include erosion or degradations that may impose constraints on the function of the cooling system and present a potential hazard to the safety of the plant. Submerged emergency canals (e.g., artificially dredged canals at the river bed or the bottom of the reservoir) should be monitored for sedimentation, debris, or instability of slopes that may impair the function of the canals under extreme low flow conditions.

Further details of parameters to be monitored and inspected for these and other water-control structures are specified in Section C.2 of NRC RG 1.127. The program is augmented to require monitoring of bolted connections for loss of material and loose bolts and nuts and other conditions indicative of loss of preload. High strength (actual measured yield strength ≥ 150 ksi or 1,034 MPa) structural bolts greater than 1 inch in diameter are monitored for stress corrosion cracking. The program is also augmented to require monitoring of wooden components for loss of material and change in material properties.

424. ***Detection of Aging Effects:*** NRC RG 1.127 specifies that inspection of water-control structures should be conducted under the direction of qualified engineers experienced in the investigation, design, construction, and operation of these types of facilities. Visual inspections are primarily used to detect degradation of water-control structures. Visual inspection of high strength structural bolting greater than 1 inch in diameter should be supplemented with volumetric or surface examinations to detect cracking. This requirement can be waived with adequate technical justification. In some cases, instruments have been installed to measure the behavior of water-control structures. NRC RG 1.127 indicates that the available records and readings of installed instruments are to be reviewed to detect any unusual performance or distress that may be indicative of degradation. NRC RG 1.127 describes periodic inspections to be performed at least once every 5 years. This interval has been shown to be adequate to detect degradation of water-control structures before a loss of an intended function. The program should include provisions for increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection. NRC RG 1.127 also describes special inspections immediately following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls.

The program should address detection of aging affects for inaccessible, below-grade, and submerged concrete structural elements. For plants with non-aggressive raw water and groundwater/soil (pH > 5.5, chlorides < 500 parts per million [ppm], or sulfates < 1500 ppm), the program should require (a) evaluating the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas and (b) examination of representative samples of the exposed portions of the below-grade concrete when excavated for any reason. Submerged concrete structures should be inspected during periods of low tide or when dewatered and accessible.

For plants with aggressive environment raw water (pH < 5.5, chlorides > 500 ppm, or sulfates > 1500 ppm) or ground water/soil and/or where the concrete structural elements have experienced degradation, a plant-specific AMP accounting for the extent of the degradation experienced should be implemented to manage the concrete aging during the period of extended operation.

425. ***Monitoring and Trending:*** Water-control structures are monitored by periodic inspection as described in NRC RG 1.127. Changes of degraded conditions from prior inspection, such as growth of an active crack or extent of corrosion, should be trended until it is evident the change is no longer occurring or until corrective actions are implemented in accordance with 10 CFR 50.65 and RG 1.160, Rev. 2.

426. ***Acceptance Criteria:*** Quantitative acceptance criteria to evaluate the need for corrective actions are not specified in NRC RG 1.127. However, the “Evaluation Criteria” provided in Chapter 5 of ACI 349.3R provides acceptance criteria (including quantitative criteria) for determining the adequacy of observed aging effects and specifies criteria for further evaluation. Although not required, plant-specific acceptance criteria based on Chapter 5 of ACI 349.3R are acceptable. Acceptance criteria for earthen structures such as canals, and embankments are consistent with programs falling within the regulatory jurisdiction of the FERC or the U.S. Army Corps of Engineers. Loose bolts and nuts, cracked high strength bolts, and degradation of piles and sheeting are accepted by engineering evaluation or subject to corrective actions. Engineering evaluation should be documented and based on codes, specifications, and standards such as AISC specifications, SEI/ASCE 11, and those referenced in the plant’s current licensing basis.

427. ***Corrective Actions:*** NRC RG 1.127 recommends that when inspection findings indicate that significant changes have occurred, the conditions are to be evaluated. This includes a technical assessment of the causes of distress or abnormal conditions, an evaluation of the behavior or movement of the structure, and recommendations for remedial or mitigating measures. Degraded bolting is evaluated for acceptability or replaced in accordance with guidelines and recommendations of EPRI TR-104213 and NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

428. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

429. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

430. ***Operating Experience:*** Degradation of water-control structures has been detected, through NRC RG 1.127 programs, at a number of nuclear power plants, and in some cases, it has required remedial action. NRC NUREG-1522 described instances and corrective actions of severely degraded steel and concrete components at the intake structure and pumphouse of coastal plants. Other degradations described in the NUREG include appreciable leakage from the spillway gates, concrete cracking, corrosion of spillway bridge beam seats of a plant dam and cooling canal, and appreciable differential settlement of the outfall structure of another. No loss of intended functions has resulted from these occurrences. Therefore, it can be concluded that the inspections implemented in accordance with the guidance in NRC RG 1.127 have been successful in detecting significant degradation before loss of intended function occurs.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

ACI Standard 201.1, *Guide for Making a Condition Survey of Concrete in Service,* American Concrete Institute, 1992.

ACI Standard 349.3R, *Evaluation of Existing Nuclear Safety-Related Concrete Structures,* American Concrete Institute, 1996, 2002.

EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel*, Volume 1: Large Bolt Manual, 1987; Volume 2: Small Bolts and Threaded Fasteners, Electric Power Research Institute, 1990.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, Electric Power Research Institute, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric Power Research Institute, December 1995.

NRC Regulatory Guide 1.127, *Inspection of Water-Control Structures Associated with Nuclear Power Plants,* Revision 1, U.S. Nuclear Regulatory Commission, March 1978.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, March 1997.

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

NUREG-1522, *Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures*, U.S. Nuclear Regulatory Commission, June 1995.

XI.S8 PROTECTIVE COATING MONITORING AND MAINTENANCE PROGRAM

Program Description

Proper maintenance of protective coatings inside containment (defined as Service Level I in Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev.1, or latest version) is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of Emergency Core Cooling Systems (ECCS) suction strainers, which reduces flow through the system and could cause unacceptable head loss for the pumps.

Maintenance of Service Level I coatings applied to carbon steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors) also serve to prevent or minimize loss of material due to corrosion of carbon steel components and aides in decontamination. Regulatory Position C4 in NRC RG 1.54, Rev. 1, describes an acceptable technical basis for a Service Level I coatings monitoring and maintenance program that can be credited for managing the effects of corrosion for carbon steel elements inside containment. The attributes of an acceptable program are described below. American Society for Testing of Materials (ASTM) D 5163-08 and endorsed years of the standard in NRC RG 1.54 are acceptable and considered consistent with NUREG-1801. In addition, Electric Power Research Institute (EPRI) Report 1003102 guidelines for inspection and maintenance of safety-related protective coatings may be used as an alternate for or as a supplement to the ASTM standard guidelines.

A comparable program for monitoring and maintaining protective coatings inside containment, developed in accordance with NRC RG 1.54, Rev.1, is acceptable as an aging management program for license renewal.

Service Level I coatings credited for preventing corrosion of containment components are subject to additional requirements specified by the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWE. These additional requirements are covered by ASME Section XI, Subsection IWE (XI.S1) aging management program and are not part of this program.

Evaluation and Technical Basis

431. ***Scope of Program:*** The minimum scope of the program is Service Level I coatings applied to steel and concrete surfaces inside containment (e.g., steel liner, steel containment shell, structural steel, supports, penetrations, and concrete walls and floors), defined in NRC RG 1.54, Rev 1, as follows: "Service Level I coatings are used in areas inside the reactor containment where the coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown." The scope of the program may also include Service Level I coatings that are credited by the licensee for preventing loss of material due to corrosion.

432. ***Preventive Action:*** The program is a condition monitoring program and does not recommend any preventive actions. However, for plants that credit coatings to minimize loss of material, this program is a preventive action.

433. ***Parameters Monitored or Inspected:*** Regulatory Position C4 in NRC RG 1.54, Rev 1, states that "ASTM D 5163-96 provides guidelines that are acceptable to the NRC staff for establishing an in-service coatings monitoring program for Service Level I coating systems in operating nuclear power plants..." ASTM D 5163-96 has been superseded by ASTM D 5163-08. ASTM D 5163-08 identifies the parameters monitored or inspected to be "any visible defects, such as blistering, cracking, flaking, peeling, rusting, and physical damage."

434. ***Detection of Aging Effects:*** ASTM D 5163-08, paragraph 6, defines the inspection frequency to be each refueling outage or during other major maintenance outages as needed. ASTM D 5163-08, paragraph 9, discusses the qualifications for inspection personnel, the inspection coordinator, and the inspection results evaluator. ASTM D 5163-08, subparagraph 10.1, discusses development of the inspection plan and the inspection methods to be used. It states, "A general visual inspection shall be conducted on all readily accessible coated surfaces during a walk-through. After a walk-through, or during the general visual inspection, thorough visual inspections shall be carried out on previously designated areas and on areas noted as deficient during the walk-through. A thorough visual inspection shall also be carried out on all coatings near sumps or screens associated with the Emergency Core Cooling System (ECCS)." This subparagraph also addresses field documentation of inspection results. ASTM D 5163-08, subparagraph 10.5, identifies instruments and equipment needed for inspection. EPRI report 1003102, Section 8, “Condition Assessment,” provides additional details of an acceptable coatings condition assessment program.

435. ***Monitoring and Trending:*** ASTM D 5163-08 identifies monitoring and trending activities in subparagraph 7.2, which specifies a pre-inspection review of the previous two monitoring reports, and in subparagraph 11.1.2, which specifies that the inspection report should prioritize repair areas as either needing repair during the same outage or postponed to future outages, but under surveillance in the interim period.

436. ***Acceptance Criteria:*** ASTM D 5163-08, subparagraphs 10.2.1 through 10.2.6, 10.3, and 10.4, contain one acceptable method for characterization, documentation, and testing of defective or deficient coating surfaces. Additional ASTM and other recognized test methods are available for use in characterizing the severity of observed defects and deficiencies. The evaluation covers blistering, cracking, flaking, peeling, delamination, and rusting. ASTM D 5163-08, paragraph 12, addresses evaluation. It specifies that the inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Repair work is prioritized as major or minor defective areas.

437. ***Corrective Actions:*** A recommended corrective action plan is required for major defective areas so that these areas can be repaired during the same outage, if appropriate. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

438. ***Confirmation Process:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

439. ***Administrative Controls:*** As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

440. ***Operating Experience***: NRC Information Notice 88-82, NRC Bulletin 96-03, NRC Generic Letter (GL) 04-02, and NRC GL 98-04 describe industry experience pertaining to coatings degradation inside containment and the consequential clogging of sump strainers. NRC RG 1.54, Rev. 1, was issued in July 2000. Monitoring and maintenance of Service Level I coatings conducted in accordance with Regulatory Position C4 is expected to be an effective program for managing degradation of Service Level I coatings.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

ASTM D 5163-05, *Guide for Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant,* American Society for Testing and Materials, 2005.

ASTM D 5163-08, *Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants,* American Society for Testing and Materials, 2008.

ASTM D 5163-96, *Standard Guide for Establishing Procedures to Monitor the Performance of Safety Related Coatings in an Operating Nuclear Power Plant,* American Society for Testing and Materials, 1996.

EPRI Report 1003102, *Guideline on Nuclear Safety-Related Coatings*, Revision 1, (Formerly TR-109937), Electric Power Research Institute, November 2001.

NRC Bulletin 96-03, *Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors*, U.S. Nuclear Regulatory Commission, May 6, 1996.

NRC Generic Letter 98-04, *Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,* U.S. Nuclear Regulatory Commission, July 14, 1998.

NRC Generic Letter 04-02, *Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors*, U.S. Nuclear Regulatory Commission, September 13, 2004.

NRC Information Notice 88-82, *Torus Shells with Corrosion and Degraded Coatings in BWR Containments*, U.S. Nuclear Regulatory Commission, November 14, 1988.

NRC Information Notice 97-13, *Deficient Conditions Associated With Protective Coatings at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, March 24, 1997.

NRC Regulatory Guide 1.54, Rev. 0, *Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, June 1973.

NRC Regulatory Guide 1.54, Rev. 1, *Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, July 2000.

XI.E1 INSULATION MATERIAL FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. Insulation materials used in electrical cables and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable or connection insulation material. The service environment is dependent on the operating specifications provided by the cable or connection insulation material manufacturer. The applicant should determine the adverse localized environment based on the most limiting manufacturer specification (temperature, radiation, or moisture) of the cables or connection insulation material bounded by this aging management program (AMP). An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

The purpose of the AMP described herein is to provide reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by temperature, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation. This AMP considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, and EPRI TR-109619.

The program described herein is written specifically to address cables and connections at plants whose configuration is such that most (if not all) cables and connections installed in adverse localized environments are accessible. If an unacceptable condition or situation is identified for a cable or connection in the inspection, a determination is made as to whether the same condition or situation is applicable to inaccessible cables or connections. As such, this program does not apply to plants in which most cables are inaccessible.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 FR 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables and connections covered by this AMP are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

441. ***Scope of Program:*** This AMP applies to accessible electrical cables and connections within the scope of license renewal that are installed in adverse localized environments caused by temperature, radiation, or moisture.

442. ***Preventive Actions:*** This is a performance monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

443. ***Parameters Monitored/Inspected:*** All accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection insulation surface anomalies. An adverse localized environment is a plant-specific condition; therefore, the applicant should clearly define how this condition is determined. The applicant should determine and inspect the adverse localized conditions for each of the most limiting temperature, radiation, or moisture conditions for the accessible electrical cables and connections that are within the scope of license renewal.

444. ***Detection of Aging Effects:*** Insulation aging degradation from temperature, radiation, or moisture causes cable and connection insulation surface anomalies. Accessible electrical cables and connections installed in adverse localized environments are visually inspected for cable and connection surface anomalies, such as insulation embrittlement, discoloration, cracking, or surface contamination. Accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years. This is an adequate period to preclude failures of the cable and connection insulation since experience has shown that aging degradation is a slow process. A 10-year inspection interval provides two data points during a 20-year period, which can be used to characterize the degradation rate. The first inspection for license renewal is to be completed before the period of extended operation.

445. ***Monitoring and Trending:*** Trending actions are not included as part of this AMP, because the ability to trend inspection results is limited. However, inspection results that are trendable provide additional information on the rate of cable or connection insulation degradation.

446. ***Acceptance Criteria:*** The accessible cables and connections are to be free from unacceptable visual indications of surface anomalies which suggest that cable or connection insulation degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function.

447. ***Corrective Actions:*** All unacceptable visual indications of cable and connection insulation surface anomalies are subject to an engineering evaluation. Such an evaluation is to consider the age and operating environment of the component as well as the severity of the anomaly and whether such an anomaly has previously been correlated to degradation of cable or connection insulation. Corrective actions may include, but are not limited to, testing, shielding, or otherwise changing the environment or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to inaccessible cables or connections. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

448. ***Confirmation Process:*** The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

449. ***Administrative Controls:*** The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the

requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

450. ***Operating Experience:*** Operating experience has shown that adverse localized environments caused by temperature radiation or moisture for electrical cables and connections may exist next to or above (within 3 feet of) steam generators, pressurizers, or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation.

References

10 CFR Part 50, Appendix B, *Quality Assurance criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. 1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E2 INSULATION MATERIAL FOR ELECTRICAL CABLES AND CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS USED IN INSTRUMENTATION CIRCUITS

Program Description

In most areas within a nuclear power plant, the actual ambient environments (e.g., temperature, radiation, or moisture) are less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment for those areas. Insulation materials used in electrical cables and connections may degrade more rapidly than expected in these adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable and connection insulation material. The service environment is dependent on the operating specification provided by the cable or connection insulation material manufacturer. The applicant should determine the adverse localized environment based on the most limiting manufacturer specification (temperature, radiation, or moisture) of the cables or connection insulation material bounded by this aging management program (AMP). An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Exposure of electrical cable and connection insulation material to adverse localized environments caused by temperature, radiation, or moisture can result in reduced insulation resistance (IR). Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for all circuits, but especially those with sensitive, high voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation circuits, because a reduced IR may contribute to signal inaccuracies.

The purpose of the AMP described herein is to provide reasonable assurance that the intended functions of electrical cables and connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in instrumentation circuits with sensitive, high voltage, low-level current signals exposed to adverse localized environments caused by temperature, radiation, or moisture are maintained consistent with the current licensing basis through the period of extended operation.

In this AMP, either of two methods can be used to identify the existence of aging degradation. In the first method, calibration results or findings of surveillance testing programs are evaluated to identify the existence of cable and connection insulation material aging degradation. In the second method, direct testing of the cable system is performed.

This AMP applies to high-range-radiation and neutron flux monitoring instrumentation cables in addition to other cables used in high voltage, low-level current signal applications that are sensitive to reduction in IR. For these cables, General Aging Lessons Learned (GALL) XI.E1 does not apply.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 FR 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables covered by this AMP are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

451. ***Scope of Program:*** This AMP applies to electrical cables and connections (cable system) used in circuits with sensitive, high voltage, low-level current signals, such as radiation monitoring and nuclear instrumentation that are installed in adverse localized environments caused by temperature, radiation, or moisture, that are within the scope of license renewal.

452. ***Preventive Actions:*** This is a performance monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

453. ***Parameters Monitored/Inspected:*** The parameters monitored are determined from the specific calibration, surveillances, or testing performed and are based on the specific instrumentation circuit under surveillance or being calibrated, as documented in plant procedures.

454. ***Detection of Aging Effects:*** Review of calibration results or findings of surveillance programs can provide an indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. The first reviews are completed before the period of extended operation and at least every 10 years thereafter. All calibration or surveillance results that fail to meet acceptance criteria are reviewed for aging effects when the results are available.

In cases where a calibration or surveillance program does not include the cabling system in the testing circuit, or as an alternative to the review of calibration results described above, the applicant performs cable system testing. A proven cable system test for detecting deterioration of the insulation system (such as insulation resistance tests, time domain reflectometry tests, or other testing judged to be effective in determining cable system insulation condition as justified in the application) is performed. The test frequency of the cable system should be determined by the applicant based on engineering evaluation, but the test frequency should be at least once every 10 years. The first test should be completed before the period of extended operation.

455. ***Monitoring and Trending:*** Trending actions are not included as part of this AMP although the ability to trend test results is dependent on the specific type of test chosen. However, test results that are trendable provide additional information on the rate of cable or connection insulation material degradation.

456. ***Acceptance Criteria:*** Calibration results or findings of surveillance and cable system testing are to be within the acceptance criteria, as set out in procedures.

457. ***Corrective Actions:*** Corrective actions, such as recalibration and circuit trouble-shooting, are implemented when calibration, surveillance, or cable system test results do not meet the acceptance criteria. An engineering evaluation is performed when the acceptance criteria are not met in order to ensure that the intended functions of the electrical cable system can be maintained consistent with the current licensing basis. Such an evaluation is to consider the significance of the calibration, surveillance, or cable system test results; the operability of the component; the reportability of the event; the extent of the concern; the potential root causes for not meeting the acceptance criteria; the corrective actions required; and likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is also made as to whether the review of calibration results and cable system testing frequency needs to be increased. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

458. ***Confirmation Process:*** The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address confirmation process.

459. ***Administrative Controls:*** The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

460. ***Operating Experience:*** This AMP considers the technical information and guidance provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, EPRI TR-109619, IN 97-45, and IN 97-45, Supplement 1. Operating experience has identified a case where a change in temperature across a high range radiation monitor cable in containment resulted in a substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable and are a possible indication of electrical cable degradation.

The vast majority of site specific and industry wide operating experience regarding neutron flux instrumentation circuits is related to cable/connector issues inside of containment near the reactor vessel.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. 1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NRC Information Notice 97-45, *Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails*, U. S, Nuclear Regulatory Commission, July 2, 1997.

NRC Information Notice 97-45, Supplement 1, *Environmental Qualification Deficiency for Cables and Containment Penetration Pigtails*, U. S, Nuclear Regulatory Commission, February 17, 1998.

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E3 INACCESSIBLE POWER CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to adverse environmental conditions, such as wetting or submergence, in inaccessible or underground locations, such as conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations. When an energized power cable (greater than or equal to 480 volts) is exposed to wet, submerged, other adverse environmental conditions for which it was not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. This insulation degradation can be caused by wetting or submergence, manufacturing defects, shipping and installation, voltage stress, electrical transients, or adverse environmental conditions during operation. This can potentially lead to failure of the cable’s insulation system.

The purpose of the aging management program (AMP) described herein is to provide reasonable assurance that the intended functions of inaccessible or underground power cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse environments will be maintained consistent with the current licensing basis through the period of extended operation. An adverse environment is a condition in a plant area that is significantly more severe than the specified service environment for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

In this AMP, periodic actions are taken to prevent cables from being exposed to significant moisture, defined as periodic exposures to moisture that last more than a few days (e.g., cable wetting or submergence in water), such as inspecting for water collection in cable manholes and conduit and draining water, as needed. The above actions are not sufficient to ensure that water is not trapped elsewhere in the raceways. For example: (a) if duct bank conduit has low points in the routing, there could be potential for long-term submergence at these low points; (b) concrete raceways may crack due to soil settling over a long period of time; (c) manhole covers may not be watertight; (d) in certain areas, the water table is high in seasonal cycles and therefore, the raceways may get refilled soon after purging; and (e) potential uncertainties exist with water trees even when duct banks are sloped with the intention to minimize water accumulation. Experience has shown that insulation degradation may occur if the cables are exposed to 100 percent relative humidity. The above periodic actions are necessary to minimize the potential for insulation degradation. In addition to above periodic actions, in-scope power cables exposed to significant moisture are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined prior to the initial test, and is to be a proven test for detecting deterioration of the insulation system due to wetting or submergence, such as Dielectric Loss (Dissipation Factor/Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the tests are performed. Combinations of different tests are required to determine the condition of the cables.

As stated in NUREG/CR-5643, "The major concern with cables is the performance of aged cable when it is exposed to accident conditions." The statement of considerations for the final license renewal rule (60 Fed. Reg. 22477) states, "The major concern is that failures of deteriorated cable systems (cables, connections, and penetrations) might be induced during accident conditions." Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, the electrical cables covered by this AMP are either not exposed to harsh accident conditions or are not required to remain functional during or following an accident to which they are exposed.

Evaluation and Technical Basis

461. ***Scope of Program:*** This AMP applies to inaccessible or underground (e.g., in conduit, duct bank, or direct buried) power (greater than or equal to 480 volt) cables within the scope of license renewal exposed to environmental aging mechanisms, primarily significant moisture. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable wetting or submergence in water). Submarine or other cables designed for continuous wetting or submergence are not included in this AMP.

462. ***Preventive Actions:*** This is a performance monitoring program. However, periodic actions are taken to prevent cables from being exposed to significant moisture, such as identifying and inspecting in-scope, conduits, cable manholes, and duct banks for water collection and draining water, as needed. Other actions may include the installation of sump pumps and alarms, the installation of permanent drainage systems, and the implementation of a cable condition monitoring program.

463. ***Parameters Monitored/Inspected:*** Inaccessible or underground power (greater than 480 volts) cables within the scope of license renewal exposed to significant moisture are tested to provide an indication of the condition of the conductor insulation. The specific type of test to be used should be proven for detecting deterioration of the insulation system due to wetting. The applicant can assess the condition of the cable insulation with reasonable confidence using one or more of the following techniques: Dielectric Loss (Dissipation Factor/Power Factor), AC Voltage Withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the tests are performed. A combination of different tests are required to determine the condition of the cables.

Inspection for water collection should be performed based on plant-specific operating experience with water accumulation in the manhole.

464. ***Detection of Aging Effects:*** Power cables exposed to significant moisture are tested at least once every 5 years. If there is no significant degradation observed, the frequency may be increased to every 10 years. This is an adequate period to monitor performance of the cable and take appropriate corrective actions since experience has shown that aging degradation is a slow process. A 5-year testing interval provides four data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for license renewal are to be completed before the period of extended operation.

The inspection frequency for water collection should be established and performed based on plant-specific operating experience with cable wetting or submergence in manholes (i.e., operation of dewatering devices should be inspected and operation verified prior to any known or predicted flooding events). The inspection should occur at least annually. The inspection should include direct observation that cables are not wetted or submerged, that cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. If water is found during inspection (i.e., cable exposed to significant moisture), corrective action should be taken to keep the cable dry and tests performed to assess cable degradation. The first inspection for license renewal is completed before the period of extended operation.

465. ***Monitoring and Trending:*** Trending actions are included as part of this program, although the ability to trend results is dependent on the specific type of method chosen. Results that are trendable provide additional information on the rate of cable insulation degradation.

466. ***Acceptance Criteria:*** The acceptance criteria for each test are defined by the specific type of test performed and the specific cable tested. Acceptance criteria for inspections of manholes are defined by the observation that the cables and support structures are not submerged or immersed in standing water at the time of the inspection.

467. ***Corrective Actions:*** Corrective actions are required and an engineering evaluation is performed when the test or inspection acceptance criteria are not met. Such an evaluation is to consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test or inspection acceptance criteria, the corrective actions required, and the likelihood of recurrence. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible, in-scope power cables. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

468. ***Confirmation Process:*** The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

469. ***Administrative Controls:*** The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

470. ***Operating Experience:*** Operating experience has shown that ethylene-propylene rubber (EPR) and cross-linked polyethylene (XPLE) or high molecular weight polyethylene (HMWPE) insulation materials are most susceptible to water tree formation. The formation and growth of water trees varies directly with operating voltage. Aging effects of reduced insulation resistance due to other mechanisms may also result in a decrease in the dielectric strength of the conductor insulation. Minimizing exposure to moisture mitigates the potential for the development of reduced insulation resistance.

Recent incidents involving early failures of electric cables and cable failures leading to multiple equipment failures, are cited in IN 2002-12, “Submerged Safety-Related Cables,” and the U.S. Nuclear Regulatory Commission (NRC) Generic Letter (GL) 2007-01, “Inaccessible or Underground Power Cable Failures That Disable Accident Mitigation Systems or Cause Plant Transients.”

The NRC issued GL 2007-001 on inaccessible or underground cables to (a) inform licensees that the failure of certain power cables can affect the functionality of multiple accident mitigation systems or cause plant transients and (b) gather inaccessible or underground power cable failures for all cables that are within the scope of the Maintenance Rule. Based on the review of licensees' responses, the NRC staff has identified 269 cable failures for 104 reactor units. The data obtained from the GL responses show an increasing trend of cable failures. The NRC staff has noted that the predominant factor contributing to cable failures at nuclear power plants was due to moisture/submergence. The staff also noted that the GL failure data show that the majority of the reported failures occurred at the 4160-volt, 480-volt, and 600-volt service voltage levels for both energized and de-energized cables. These cables are failing within the plants' 40-year licensing periods.

The NRC inspectors also have continued to identify safety related cables which are submerged. During recent license renewal audits at several facilities, the staff observed water levels ranging up to around 12 feet inside the manholes. The staff noted that licensees had not demonstrated that the subject safety related cables were designed for wetted or submerged service for the current license period.

Therefore, based on the operating experience, the staff revised the scope of GALL AMP XI.E3 to include all inaccessible or underground power cables at voltage levels greater than or equal to480 volts. This ensures that all power cable conditions are monitored by inspection and testing to demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation.

This AMP considers the technical information and generic communication guidance provided in NUREG/CR-5643; IEEE Std. 1205-2000; SAND96-0344; EPRI TR-109619; EPRI TR-103834-P1-2; Information Notice [IN] 2002-12; IN 1989-63; GL 2007-01; GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, *Flood Protection Measures*; and NRC Inspection Procedure, Attachment 71111.01, *Adverse Weather Protection.*

As additional operating experience is obtained, lessons learned can be used to adjust this AMP as needed.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

EPRI TR-103834-P1-2, *Effects of Moisture on the Life of Power Plant Cables,* Electric Power Research Institute, Palo Alto, CA, August 1994.

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments,* Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. 1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NRC Inspection Procedure, Attachment 71111.06, *Flood Protection Measures*, June 25, 2009.

NRC Inspection Procedure, Attachment 71111.01, *Adverse Weather Protection*, April 8, 2009.

NRC Information Notice 1989-63, *Possible Submergence of Electrical Circuits Located Above the Flood Level Because of Water Intrusion and Lack of Drainage*, September 5, 1989.

NRC Information Notice 2002-12, *Submerged Safety-Related Electrical Cables*, March 21, 2002.

NRC Generic Letter 2007-01, *Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients*, February 7, 2007.

NRC Generic Letter 2007-01, Summary Report, *Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients*, November 12, 2008.

NUREG/CR-5643, *Insights Gained From Aging Research,* U. S. Nuclear Regulatory Commission, March 1992.

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations,* prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E4 METAL ENCLOSED BUS

Program Description

Metal enclosed buses (MEBs) are electrical buses installed on electrically insulated supports and are constructed with each phase conductor enclosed in a separate metal enclosure (isolated phase bus) or all conductors enclosed in a common metal enclosure (non-segregated bus). The conductors are adequately separated and insulated from ground by insulating supports. Also, the conductors in the non-segregated bus are insulated throughout the conductor length to reduce corona and electrical tracking. The MEBs are used in power systems to connect various elements in electric power circuits, such as switchgear, transformers, main generators, and diesel generators.

Industry operating experience indicates that failures of MEBs have been caused by cracked insulation and moisture or debris buildup internal to the bus duct housing. Failures of MEBs have also been attributed to the cracking of bus bar insulation (bus sleeving) combined with the accumulation of moisture or debris in the bus bar enclosure. Cracked insulation has resulted from high ambient temperature and contamination from bus bar joint compounds. Cracked insulation in the presence of moisture or debris has provided phase-to-phase or phase-to-ground electrical tracking paths, which has resulted in catastrophic failure of the buses. Bus failure has led to loss of power to electrical loads connected to the buses, causing subsequent reactor trips and initiating unnecessary challenges to plant systems and operators.

MEBs may experience increased resistance of connection due to loosening of bolted bus duct connections caused by repeated thermal cycling of connected loads. This phenomenon can occur in heavily loaded circuits (i.e., those exposed to appreciable ohmic heating). For example, SAND 96-0344 identified instances of termination loosening at several plants due to thermal cycling and U.S. Nuclear Regulatory Commission (NRC) Information Notice (IN) 2000-14 identified torque relaxation of splice plate connecting bolts as one potential cause of a MEB fault. Therefore, the purpose of this aging management program (AMP) is to provide an internal and external inspection of MEBs to identify age-related degradation of insulating material (i.e., porcelain, xenoy, thermoplastic organic polymers), and metallic and elastomer components (e.g., gaskets, boots, and sealants). This AMP includes the inspection of all bus ducts and a sample of accessible MEB bolted connections for increased resistance of connection. The technical basis for the sample selections is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other connections not tested.

Evaluation and Technical Basis

471. **Scope of Program:** This AMP manages the age-related degradation effects for electrical bus bar bolted connections, bus bar insulation, bus bar insulating supports, bus enclosures and enclosure supports (both internal and external), and elastomers for MEBs within the scope of license renewal.

472. **Preventive Actions:** This is a performance monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

473. **Parameters Monitored/Inspected:** This AMP provides for the inspection of the internal and external portions of the MEB. Internal portions of the MEB are inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus

insulation is inspected for signs of reduced insulation resistance due to thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation; moisture/debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, discoloration, or swelling, which may indicate overheating or aging degradation. The internal bus supports are inspected for structural integrity and signs of cracks. A sample of accessible bolted connections is inspected for increased resistance of connection. Alternatively, bolted connections covered with heat shrink tape, sleeving, insulating boots, etc. may be visually inspected for insulation material surface anomalies. The external portions of the MEB, including accessible gaskets, boots, and sealants, are inspected for hardening and loss of strength due to elastomer degradation that could permit water or foreign debris to enter the bus. MEB external surfaces and MEB bus enclosure supports (the structural supports for the entire bus assembly) are inspected for loss of material due to general corrosion.

474. Detection of Aging Effects: MEB internal surfaces are visually inspected for aging degradation including cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. MEB insulating material is visually inspected for signs of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. Internal bus supports are visually inspected for structural integrity and signs of cracks. MEB external surfaces and bus enclosure supports are visually inspected for loss of material due to general corrosion. Accessible elastomers (e.g., gaskets, boots, and sealants) are inspected for degradation including cracking, shrinkage, hardening and loss of strength.

A sample of accessible bolted connections is inspected for increased resistance of connection by using thermography or by measuring connection resistance using a low range ohmmeter. The technical basis for the sample selections is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other connections not tested. As an alternative to thermography or measuring connection resistance of bolted connections, for accessible bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc., the applicant may use visual inspection of insulation material to detect surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. When this alternative visual inspection is used to check bolted connections, the first inspection is completed before the period of extended operation and every 5 years thereafter.

This program is completed before the period of extended operation and every 10 years thereafter provided visual inspection is not used to inspect bolted connections. A 10-year inspection interval provides two data points during a 20-year period, which can be used to characterize the degradation rate. This is an adequate period to preclude failures of the MEBs since experience has shown that MEB aging degradation is a slow process.

475. Monitoring and Trending: Trending actions are not included as part of this program because the ability to trend inspection results is limited. However, results that are trendable provide additional information on the rate of degradation.

476. Acceptance Criteria: MEB insulation materials are free from regional indications of surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, and swelling, or surface contamination. MEB internal surfaces show no indications of corrosion, cracks, foreign debris, excessive dust buildup, or evidence of moisture intrusion. Accessible gaskets, boots, and sealants show no indications of cracking, shrinkage, hardening, and loss of strength. MEB external surfaces and bus enclosure supports are free from loss of material/general corrosion.

Bolted connections need to be below the maximum allowed temperature for the application when thermography is used or a low resistance value appropriate for the application when resistance measurement is used. When the visual inspection alternative for bolted connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination of the insulation material provides positive indication that the bolted connections are not loose.

477. Corrective Actions: Corrective actions are required and an engineering evaluation is performed when the acceptance criteria are not met. Corrective actions may include, but are not limited, to cleaning, drying, increased inspection frequency, replacement, or repair of the affected MEB components. If an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible MEBs. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

478. Confirmation Process: The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

479. Administrative Controls: The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

480. Operating experience: Industry experience has shown that failures have occurred on MEBs caused by cracked insulation and moisture or debris buildup internal to the MEB. Experience has also shown that bus connections in the MEBs exposed to appreciable ohmic heating during operation may experience loosening due to repeated cycling of connected loads. Degradation of hydrostatic barriers has resulted in water leaking into areas containing safety-related equipment (NRC IN 2007-01).

This AMP considers the technical information and guidance provided in SAND 96-0344, IEEE Std. 1205-2000, NRC IN 89-64, IN 98-36, IN 2000-14, and IN 2007-01.

References

10 CFR Part 50, Appendix B, *Quality Assurance criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

IEEE Std. 1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations*.

NRC Information Notice 89-64, *Electrical Bus Bar Failures*, September 7, 1989.

NRC Information Notice 98-36, *Inadequate or Poorly Controlled, Non-Safety-Related Maintenance Activities Unnecessary Challenged Safety Systems*, September 18, 1998.

NRC Information Notice 2000-14, *Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power*, September 27, 2000.

NRC Information Notice 2007-01, *Recent Operating Experience Concerning Hydrostatic Barriers*, January 31, 2007.

SAND 96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations*, prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

XI.E5 FUSE HOLDERS

Program Description

Fuse holders (fuse blocks) are classified as a specialized type of terminal block because of the similarity in fuse holder design and construction to that of a terminal block. Fuse holders are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps (clips) are attached to the blocks to hold each end of the fuse. The clamps, which are typically made of copper, can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs, to which the fuse ends are bolted.

Generic Aging Lessons Learned (GALL) XI.E1, "Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," manages the aging of insulating material but not the metallic clamps of the fuse holders. The aging management program (AMP) for fuse holders (metallic clamps) needs to account for the following aging stressors if applicable: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, electrical transients, frequent manipulation, or vibration. GALL XI.E1 is based on only a visual inspection of accessible cables and connections. Visual inspection is not sufficient to detect the aging effects from chemical contamination, corrosion, oxidation, fatigue, or vibration on the metallic clamps of the fuse holder.

Fuse holders that are within the scope of license renewal should be tested to provide an indication of the condition of the metallic clamps of the fuse holders. The specific type of test performed is determined prior to the initial test and is to be a proven test for detecting deterioration of metallic clamps of the fuse holders, such as thermography, contact resistance testing, or other appropriate testing justified in the application.

As stated in NUREG-1760, "Aging Assessment of Safety-Related Fuses Used in Low and Medium-Voltage Applications in Nuclear Power Plants," fuse holders experience a number of age-related failures. The major concern is that failures of a deteriorated cable system (cables, connections including fuse holders, and penetrations) might be induced during accident conditions. Since they are not subject to the environmental qualification requirements of 10 CFR 50.49, an AMP is required to manage the aging effects. This AMP ensures that fuse holders will perform their intended function for the period of extended operation.

Evaluation and Technical Basis

481. **Scope of Program:** This AMP manages fuse holders (metallic clamps) located outside of active devices and are considered susceptible to the following aging effects: increased resistance of connection due to chemical contamination, corrosion, and oxidation or fatigue caused by ohmic heating, thermal cycling, frequent manipulation, or vibration. Fuse holders inside an active device (e.g., switchgear, power supplies, power inverters, battery chargers, and circuit boards) are not within the scope of this AMP.

482. **Preventive Actions:** This is a performance monitoring program and no actions are taken as part of this program to prevent or mitigate aging degradation.

483. **Parameters Monitored/Inspected:** Metallic clamp portion of the fuse holder is tested to provide an indication of increased resistance of the connection due to chemical contamination, corrosion, and oxidation or fatigue.

484. **Detection of Aging Effects:** Fuse holders within the scope of license renewal are tested at least once every 10 years to provide an indication of the condition of the metallic clamp of the fuse holder. Testing may include thermography, contact resistance testing, or other appropriate testing methods. This is an adequate period to preclude failures of the fuse holders since experience has shown that aging degradation is a slow process. A 10-year testing interval provides two data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for license renewal are to be completed before the period of extended operation.

485. **Monitoring and Trending:** Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. However, results that are trendable provide additional information on the rate of degradation.

486. **Acceptance Criteria:** The acceptance criteria for each test are defined by the specific type of test performed and the specific type of fuse holder tested. The metallic clamp of the fuse holder needs to be below the maximum allowed temperature for the application when thermography is used; otherwise, a low resistance value appropriate for the application is used.

487. **Corrective Action:** Corrective actions are required and an engineering evaluation is performed when the test acceptance criteria are not met in order to ensure that the intended functions of the fuse holders can be maintained consistent with the current licensing basis. Such an evaluation is to consider the significance of the test results, the operability of the component, the reportability of the event, the extent of the concern, the potential root causes for not meeting the test acceptance criteria, the corrective action necessary, and the likelihood of recurrence. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

488. **Confirmation Process:** The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

489. **Administrative Controls:** The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

490. **Operating Experience:** Operating experience has shown that loosening of fuse holders and corrosion of fuse clips are aging mechanisms that, if left unmanaged, can lead to a loss of electrical continuity function. Operating experience in NUREG-1760 documented fuse holder failures due to fatigue and recommends maintenance procedures be reviewed to minimize removal and reinsertion of fuses to de-energize components (as this can lead to degradation of the fuse holders).

This AMP considers the technical information and guidance provided in NUREG-1760, IEEE Std. 1205-2000, Information Notice (IN) 86-87, IN 87-42, and IN 91-78.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

IEEE standard 1205-2000, *IEEE Guide for Assessing, Monitoring, and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations*.

NRC Information Notice 86-87, *Loss of Offsite Power Upon an Automatic Bus Transfer*, October 10, 1986.

NRC Information Notice 87-42, *Diesel Generator Fuse Contacts*, September 4, 1987.

NRC Information Notice 91-78, *Status Indication of Control Power for Circuit Breakers Used in Safety-Related Application,* November 28, 1991.

NUREG-1760, *Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants*, May 31, 2002.

XI.E6 ELECTRICAL CABLE CONNECTIONS NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

Program Description

Cable connections are used to connect cable conductors to other cable conductors or electrical devices. Connections associated with cables within the scope of license renewal are part of this aging management program (AMP). The most common types of connections used in nuclear power plants are splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks. Most connections involve insulating material and metallic parts. This AMP focuses on the metallic parts of the electrical cable connections. This AMP provides a one-time test, on a sampling basis, to confirm the absence of age-related degradation of cable connections resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation.

Generic Aging Lessons Learned (GALL) XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements," manages the aging of insulating material but not the metallic parts of the electrical connections. GALL XI.E1 is based on only a visual inspection of accessible cables and connections. Visual inspection may not be sufficient to detect the aging effects from thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation on the metallic parts of cable connections.

Electrical cable connections exposed to appreciable ohmic or ambient heating during operation may experience increased resistance of connection caused by repeated cycling of connected loads or of the ambient temperature environment. Different materials used in various cable system components can produce situations where stresses between these components change with repeated thermal cycling. For example, under loaded conditions, ohmic heating may raise the temperature of a compression terminal and cable conductor well above the ambient temperature, thereby causing thermal expansion of both components. Thermal expansion coefficients of different materials may alter mechanical stresses between the components so that the termination may be adversely impacted. When the current is reduced, the affected components cool and contract. Repeated cycling in this fashion can cause loosening of the termination and may lead to increased resistance of connection or eventual separation of compression-type terminations. Threaded connectors may loosen if subjected to significant thermally-induced stress and cycling.

Cable connections within the scope of license renewal should be tested at least once prior to the period of extended operation to provide an indication of the integrity of the cable connections. The specific type of test to be performed is a proven test for detecting increased resistance of connection, such as thermography, contact resistance testing, or another appropriate test. As an alternative to thermography or resistance measurement of cable connections, for the accessible cable connections that are covered with insulation materials such as tape, the applicant may perform visual inspection of insulation material to detect aging effects for covered cable connections. When this alternative visual inspection is used to check cable connections, the applicant must use periodic inspections and cannot use a one-time test to confirm the absence of age-related degradation of cable connections. The basis for performing only a periodic visual inspection is documented.

This AMP, as described, can be thought of as a sampling program. The following factors are considered for sampling: voltage level (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections is documented. If an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other connections not tested. The corrective action program is used to evaluate the condition and determine appropriate corrective action.

SAND96-0344, "Aging Management Guidelines for Electrical Cable and Terminations," indicated loose terminations were identified by several plants. The major concern is failures of a deteriorated cable system (cables, connections including fuse holders, and penetrations) that could prevent it from performing its intended function. This AMP is not applicable to cable connections in harsh environments since they are already addressed by the requirements of 10 CFR 50.49. Even though cable connections may not be exposed to harsh environments, increased resistance of connection is a concern due to aging mechanisms discussed above.

Evaluation and Technical Basis

491. ***Scope of Program*****:** Cable connections associated with cables within the scope of license renewal, which are external connections terminating at active or passive devices, are in the scope of this AMP. Wiring connections internal to an active assembly are considered part of the active assembly and therefore, are not within the scope of this AMP. This AMP does not include high-voltage (>35 kilovolts) switchyard connections. The cable connections covered under the environmental qualification program are not included in the scope of this program.

492. ***Preventive Actions*****:** This is a performance monitoring program, and no actions are taken as part of this program to prevent or mitigate aging degradation.

493. ***Parameters Monitored/Inspected*****:** This AMP focuses on the metallic parts of the connection. The one-time testing verifies that increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging effect that requires periodic testing. A representative sample of electrical cable connections is tested. The following factors are considered for sampling: voltage level (medium and low voltage), circuit loading (high load), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selection is documented.

494. ***Detection of Aging Effects*****:** A representative sample of electrical connections within the scope of license renewal is tested at least once prior to the period of extended operation to confirm that there are no aging effects requiring management during the period of extended operation. Testing may include thermography, contact resistance testing, or other appropriate testing methods without removing the connection insulation, such as heat shrink tape, sleeving, etc. The one-time test provides additional confirmation to support industry operating experience that shows electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective.

As an alternative to thermography or measuring connection resistance of cable connections, for the accessible cable connection that are covered with heat shrink tape, sleeving, etc., the applicant may use visual inspection of insulation materials to detect surface anomalies, such as embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination. When this alternative visual inspection is used to check cable connections, the first inspection is completed before the period of extended operation and every 5 years thereafter. The basis for performing only a periodic visual inspection to monitor age-related degradation of cable connections is documented.

495. ***Monitoring and Trending*:** Trending actions are not included as part of this program because it is a one-time testing program.

496. ***Acceptance Criteria*:** Cable connections should not indicate abnormal temperature for the application when thermography is used; otherwise a low resistance value appropriate for the application is used. When the visual inspection alternative for covered cable connections is used, the absence of embrittlement, cracking, chipping, melting, discoloration, swelling or surface contamination provides positive indication that the covered cable connection components are not loose.

497. ***Corrective Actions*:** If acceptance criteria are not met, the corrective action program is used to perform an evaluation that considers the extent of the condition, the indications of aging effect, and changes to the one-time testing program or alternative inspection program. Corrective actions may include, but are not limited to, sample expansion, increase inspection frequency, and replacement or repair of the affected cable connection components. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

498. ***Confirmation Process*:** The confirmation process ensures that prevention and mitigation programs are adequate and that appropriate corrective actions have been completed and are effective. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

499. ***Administrative Controls*:** The administrative controls for this AMP provide for a formal review and approval process. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

500. ***Operating Experience*:** Electrical cable connections exposed to appreciable ohmic or ambient heating during operation may experience increased resistance of connection caused by repeated cycling of connected loads or of the ambient temperature environment. There have been limited numbers of age-related failures of cable connections reported. This one-time inspection confirms the absence of aging degradation of metallic cable connections.

This AMP considers the technical information and guidance provided in NUREG/CR-5643, SAND96-0344, IEEE Std. 1205-2000, EPRI TR-109619, EPRI TR-104213, NEI White Paper on GALL AMP XI.E6, Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02, Staff Response to the NEI White Paper on GALL AMP XI.E6, LER 361 2007005, LER 3612007006 and LER 3612008006.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

10 CFR 50.49, *Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2007.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide*, Electric Power Research Institute, Palo Alto, CA, December 1995.

EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments*, Electric Power Research Institute, Palo Alto, CA, June 1999.

IEEE Std. 1205-2000, *IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations.*

NEI White Paper on GALL AMP XI.E6 (Electrical Cables), Nuclear Energy Institute, September 5, 2006. (ADAMS Accession Number ML062770105)

NUREG/CR-5643, *Insights Gained From Aging Research*, U.S. Nuclear Regulatory Commission, March 1992.

Proposed License Renewal Interim Staff Guidance LR-ISG-2007-02: Changes to Generic Aging Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*, Solicitation of Public Comment, 72 FR 51256, U.S. Nuclear Regulatory Commission, September 6, 2007.

Staff's Response to the NEI White Paper on Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, *Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements*, U.S. Nuclear Regulatory Commission, March 16, 2007. (ADAMS Accession Number ML070400349)

SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations*, prepared by Sandia National Laboratories for the U.S. Department of Energy, September 1996.

LER 361 2007005, *San Onofre Unit 2, Loose Electrical Connection Results in Inoperable Pump Room Cooler*.

LER 3612007006, *San Onofre Units 2 and 3, Loose Electrical Connection Results in One Train of Emergency Chilled Water (ECW) System Inoperable*.

LER 3612008006, *San Onofre 2,Loose Connection Bolting Results in Inoperable Battery and TS Violation.*