Appendix A

Updated Safety Analysis Report Supplement

River Bend Station
License Renewal Application

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INTRODUCTION

This appendix provides the information to be submitted in an Updated Safety Analysis Report (USAR) Supplement as required by 10 CFR 54.21(d) for the River Bend Station (RBS) License Renewal Application (LRA). Appendix B of the RBS LRA provides descriptions of the programs and activities that manage the effects of aging for the period of extended operation. Section 4 of the LRA documents the evaluations of time-limited aging analyses for the period of extended operation. Appendix B and Section 4 have been used to prepare the summary program and activity descriptions for this appendix.

The information presented in this section will be incorporated into the USAR following issuance of the renewed operating license. Upon inclusion of the USAR Supplement in the RBS USAR, future changes to the descriptions of the programs and activities will be made in accordance with 10 CFR 50.59.

The following information documents aging management programs and activities credited in the RBS license renewal review (Section A.1) and time-limited aging analyses evaluated for the period of extended operation (Section A.2).

CHAPTER A

AGING MANAGEMENT PROGRAMS AND ACTIVITIES

The RBS license renewal application (Reference A.3-1) and information in subsequent related correspondence provided sufficient basis for the NRC to make the findings required by 10 CFR 54.29 (Final Safety Evaluation Report) (Reference A.3-2). As required by 10 CFR 54.21(d), this USAR supplement contains a summary description of the programs and activities for managing the effects of aging (Section A.1) and a description of the evaluation of time-limited aging analyses for the period of extended operation (Section A.2). The period of extended operation is the 20 years after the expiration date of the original operating license for RBS.

A.1 AGING MANAGEMENT PROGRAMS

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that structures and components subject to aging management review will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. Aging management programs will be implemented prior to entering the period of extended operation.

The corrective action, confirmation process, and administrative controls of the RBS (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation. RBS quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The RBS Quality Assurance Program applies to safety-related and important to safety structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the established RBS corrective action program and document control program and are applicable to all aging management programs and activities during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

Operating experience from plant-specific and industry sources is identified and systematically reviewed on an ongoing basis. The RBS corrective action program, which is implemented in accordance with the quality assurance program, effects the documentation and evaluation of plant-specific operating experience. The RBS operating experience program, which meets the provisions of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff," systematically evaluates industry operating experience. The operating experience program includes active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.

In accordance with these programs, site-specific and industry operating experience items are screened to determine whether they involve lessons learned that may impact aging management programs (AMPs). Items are evaluated, and affected AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined that the effects of aging are not adequately managed. Plant-specific operating experience associated with managing the effects of aging is reported to the industry in accordance with guidelines established in the operating experience review program.

Training provided for personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience, as well as for personnel responsible for implementing AMPs, is based on the complexity of the job performance requirements and assigned responsibilities. Training is scheduled on a recurring basis, which accommodates the turnover of plant personnel and the need for new training content.

A.1.1 Aboveground Metallic Tanks

The Aboveground Metallic Tanks Program manages loss of material for the nonsafety-related aluminum condensate storage tank (CST), which is located outdoors on sand and concrete. Preventive measures to mitigate corrosion were applied during construction, such as using the appropriate materials and use of a protective multi-layer vapor barrier beneath the tank. The inner volume of the concrete ring foundation is filled with clean dry sand, which is sloped downward from the tank center to the tank exterior. The protective multi-layer vapor barrier beneath the tank serves as a seal at the concrete-to-tank interface. There are no indoor tanks included in this program.

Interior and exterior surfaces of the CST will be inspected. The program will also perform ultrasonic testing (UT) of the CST tank bottom to assess the thickness against the design specified thickness during each 10-year period starting 10 years before the period of extended operation.

This program will be implemented prior to the period of extended operation.

A.1.2 Bolting Integrity

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for pressure-retaining closure bolting using preventive measures and inspection activities. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program includes the inspection activities required by ASME Section XI for ASME Class 1, 2 and 3 pressure-retaining bolting. For ASME Class 1, 2 and 3 bolting and non-ASME Code class bolts, periodic system inspections (at least once per refueling cycle) ensure identification of indications of loss of preload, cracking, and loss of material before leakage becomes excessive. Submerged pressure-retaining bolting will be inspected at least once every 10 years.

In addition to periodic visual inspections with components in service, visual inspection of bolting heads, nuts and threads is performed on a representative sample of closure bolting during each 10-year interval of the period of extended operation. If the number of opportunistic inspections is insufficient, the program will provide for additional directed inspections necessary to achieve a sample of 20 percent of the population (for each material/environment combination) up to a maximum of 25 bolts during each 10-year interval of the period of extended operation.

Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, were used to develop the program implementing procedures. The Structures Monitoring Program (Section A.1.41) manages the aging effects on structural bolting.

The preventive measures of the Bolting Integrity Program manage loss of preload for buried fire water system bolting, which is inspected under the Buried and Underground Piping and Tanks Inspection Program (Section A.1.4).

The Bolting Integrity Program will be enhanced as follows.

- Revise Bolting Integrity Program procedures to include submerged closure bolting for pressure-retaining components.

- Revise Bolting Integrity Program procedures to volumetrically examine high-strength bolting (regardless of code classification) (i.e., bolting with actual yield strength greater than or equal to 150 ksi) for cracking in accordance with ASME Section XI, Table IWB-2500-1, Examination Category B-G-1.

- Revise Bolting Integrity Program documents to specify visual inspection of a representative sample of closure bolting (bolt heads, nuts, and threads) in air environments. A representative sample will be 20 percent of the population (for each material/environment combination) up to a maximum of 25 fasteners during each 10-year period of the period of extended operation. The inspections will be performed when the bolting is removed to the extent that the bolting threads and bolt heads are accessible for inspections that cannot be performed during visual inspection with the threaded fastener installed.

Enhancements will be implemented prior to the period of extended operation.

A.1.3 Boraflex Monitoring

The Boraflex Monitoring Program manages reduction in neutron-absorbing capacity and change in material properties in the Boraflex material affixed to spent fuel racks. A monitoring program for the Boraflex panels in the spent fuel storage racks is implemented to assure that degradation of the Boraflex material does not compromise the criticality analysis in support of the design of spent fuel storage racks. The program uses the RACKLIFE predictive computer code or equivalent to calculate the gamma dose absorbed by and the amount of boron carbide loss from the Boraflex panels.

The program entails (a) periodic sampling and analysis for silica levels in the spent fuel pool water and trending the results using the RACKLIFE code or equivalent, (b) performing periodic physical measurements of test coupons containing Boraflex material that have been located in the spent fuel pool, and (c) areal Boron-10 (B-10) density measurement testing of the spent fuel storage racks, such as BADGER [B-10 Areal Density Gage for Evaluating Racks] testing, at a frequency of not less than once every five years. This program assures that the required 5 percent sub-criticality margin is maintained.

The Boraflex Monitoring Program will be enhanced as follows.

- Revise Boraflex Monitoring Program procedures to include areal B-10 density measurement testing of the spent fuel storage racks, such as BADGER testing, at a frequency of at least once every five years.

The enhancement will be implemented prior to the period of extended operation.

A.1.4 Buried and Underground Piping and Tanks Inspection

The Buried and Underground Piping and Tanks Inspection Program manages the effects of aging on external surfaces of buried piping components and tanks subject to aging management review. Components included in the program are fabricated from metallic materials. The program will manage loss of material and cracking through preventive and mitigative features (e.g., coatings, backfill quality, and cathodic protection) and periodic inspection activities during opportunistic and directed excavations. The number of inspections is based on the availability and effectiveness of preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, where the acceptance criteria for effectiveness of cathodic protection is other than -850 millivolts (mV) instant off, loss of material rates are measured.

Inspections are conducted by qualified individuals. Where the coatings, backfill, or condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. If a lack of soil corrosivity as determined by soil testing is used as a basis for a reduction in the number of inspections, then soil testing is conducted at least once in each 10-year period starting 10 years prior to the period of extended operation.

This program will be implemented prior to the period of extended operation.

A.1.5 BWR CRD Return Line Nozzle

The BWR Control Rod Drive (CRD) Return Line Nozzle Program manages cracking of the CRD return line (CRDRL) reactor pressure vessel nozzle using preventive, mitigative, and inservice inspection activities. The CRDRL nozzle, which is exposed to a reactor coolant environment, was capped during construction prior to plant operation. This examination program originated through NUREG-0619 but is now governed by ASME Code, Section XI. Therefore, augmented inspections specified by NUREG-0619 are not applicable. The CRDRL inner radius is volumetrically examined to monitor the effects of cracking in accordance with the ASME Code, Section XI as part of the ISI Program. The examination is performed at least once each ISI interval. The scope of the program includes the CRDRL nozzle, the nozzle-to-reactor vessel weld, the CRDRL nozzle cap, and the Inconel end cap to carbon steel safe end dissimilar metal weld. The nozzle, cap, and associated welds are included in the visual inspection (VT-2) during the reactor pressure test performed after each refueling outage.

Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI, IWB-3512. Repair and replacement are in accordance with the requirements of ASME Section XI, IWA-4000.

A.1.6 BWR Feedwater Nozzle

The BWR Feedwater Nozzle Program manages cracking due to cyclic loading on the reactor vessel's four feedwater nozzles using periodic inspection activities. Volumetric examination of the feedwater nozzle inner radii is performed in accordance with ASME Code, Section XI, Examination Category B-D. The inspections are performed at least once each ISI interval. Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI, IWB-3512. This examination program originated through NUREG-0619 but is now governed by ASME Code, Section XI.

A.1.7 BWR Penetrations

The BWR Penetrations Program manages cracking due to cyclic loading or stress corrosion cracking (SCC) and intergranular SSC (IGSCC) of BWR instrument penetrations, CRD housing and incore housing penetrations, and core plate differential pressure (ΔP)/standby liquid control penetrations. The program is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel penetration welds.

Inspections are performed in accordance with the guidelines of BWRVIP-49-A for the instrument penetrations, BWRVIP-47-A for the CRD housing and incore housing penetrations, and BWRVIP-27-A for the core plate ΔP/standby liquid control penetrations. The guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A provide information on the type of penetrations, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. During each refueling outage, a visual inspection (VT-2) of the instrument penetrations, CRD housing and incore housing penetrations, and core plate ΔP/standby liquid control penetrations are performed during the reactor coolant pressure boundary system leakage test. These BWRVIP guidelines also provide details on evaluation of flaws, expansion of scope as required, and acceptance criteria.

A.1.8 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking Program manages IGSCC in stainless steel, cast austenitic stainless steel (CASS), and nickel alloy reactor coolant pressure boundary piping and piping welds 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93°C (200°F) during power operation regardless of code classification.

The program addresses the management of crack initiation and growth due to IGSCC in the reactor coolant piping, welds, and components through the implementation of the ISI program in accordance with ASME Code, Section XI. Inservice inspections performed as augmented examinations of the Section XI ISI program ensure that aging effects are identified and repaired before the component's loss of intended function.

The inspection frequency for welds classified as Category C is in accordance with the recommendations provided in the staff-approved BWRVIP-75-A. Welds classified as Category A are subsumed into the risk-informed inservice inspection (RI-ISI) program in accordance with the June 30, 2010, NRC safety evaluation that approved RI-ISI at RBS. During the period of extended operation, at least 10 percent of the Category A welds are inspected during each ISI interval. RBS has only Category A and C welds. The program includes preventive measures including the mechanical stress improvement process (MSIP) to minimize stress corrosion cracking.

A.1.9 BWR Vessel ID Attachment Welds

The BWR Vessel ID [inside diameter] Attachment Welds Program manages cracking in structural welds for BWR reactor vessel internal integral attachments. The program is implemented through station procedures that provide for mitigation of cracking of reactor vessel internal components through control of reactor water chemistry as described in the Water Chemistry Control – BWR Program (Section A.1.42) and condition monitoring through in-vessel examinations of the reactor vessel internal attachment welds.

The program uses inspections, scheduling, acceptance criteria, and flaw evaluation in conformance with BWRVIP guidelines, including BWRVIP-48-A. The program includes welds between the vessel wall and vessel ID brackets that attach components to the vessel. The internal attachment weld can be a simple weld or a weld build-up pad on the vessel.

A.1.10 BWR Vessel Internals

The BWR Vessel Internals Program manages cracking, loss of preload, loss of material, and reduction in fracture toughness for BWR vessel internal components in a reactor coolant environment. The program performs inspections and flaw evaluation in conformance with the guidelines of applicable BWRVIP reports. The program also mitigates the aging effects by controlling water chemistry with the Water Chemistry Control – BWR Program (Section A.1.42).

This program includes (1) determining the susceptibility of cast austenitic stainless steel components to thermal embrittlement, (2) accounting for the synergistic effect of thermal aging and neutron irradiation, and (3) implementing a supplemental examination program, as necessary.

Thermal and/or neutron embrittlement in susceptible CASS and X-750 components are indirectly managed by performing periodic visual inspections capable of detecting cracks in the component. This program provides screening criteria of CASS components to determine the susceptibility to thermal aging on the basis of casting method, molybdenum content, and percent ferrite. The program also manages aging effects in stainless steel and nickel alloy components. Precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel) materials and martensitic stainless steel (e.g., 403, 410, 431 steel) are not used in the RBS reactor vessel internal components. The crack growth rate evaluations and fracture toughness values specified in BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100, Revision 1, are used for cracked core shroud welds exposed to the neutron fluence values specified in these BWRVIP reports.

Applicable industry standards and staff-approved BWRVIP documents provide the basis for scheduling inspections to provide timely detection of aging effects, appropriate NDE inspection techniques, acceptance criteria, flaw evaluation, and repair/replacement, as needed.

The BWR Vessel Internals Program will be enhanced as follows.

- Revise BWR Vessel Internals Program procedures to state that for core shroud repairs or other IGSCC repairs, the program will maintain operating tensile stresses below a threshold limit that precludes IGSCC of X-750 material.

- The susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS and X-750 alloy will be evaluated.

- Revise BWR Vessel Internals Program procedures as follows: Portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions) will be inspected, using an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within five years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100 percent of the accessible component population, excluding components that may be in compression during normal operations.

Enhancements will be implemented prior to the period of extended operation.

A.1.11 Coating Integrity

The Coating Integrity Program entails periodic visual inspections of coatings applied to the internal surfaces of in-scope components in an environment of treated water, waste water, or lubricating oil where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s). For coated surfaces that do not meet the acceptance criteria, coating repair or replacement is accompanied by physical testing where possible. The training and qualification of individuals involved in coating inspections of noncementitious coatings are in accordance with ASTM standards endorsed in Regulatory Guide (RG) 1.54, including limitations, if any, identified in RG 1.54 for those standards. For cementitious coatings or linings, inspectors should have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings or linings or a degree in the civil/structural discipline and a minimum of one year of experience.

This program will be implemented prior to the period of extended operation.

A.1.12 Compressed Air Monitoring

The Compressed Air Monitoring Program manages loss of material in compressed air systems by periodically monitoring the air for moisture and contaminants and by inspecting system internal surfaces. Air quality is maintained in accordance with limits based on consideration of manufacturer recommendations as well as guidelines in EPRI NP-7079, EPRI TR-108147, ASME OM-S/G-1998 (Part 17), and ANSI/ISA-S7.0.01-1996. Inspection frequencies and acceptance criteria are in accordance with SOER 88-01 and applicable industry standards. Documents such as EPRI NP-7079, ASME OM-S/G-1998 (Part 17), and ANSI/ISA-S7.0.1-1996 provide guidance on preventive measures, inspection of components, and testing and monitoring air quality. Periodic and opportunistic internal visual inspections of components (accumulators, flex hoses, tubing, etc.) are performed to monitor for signs of corrosion. Air quality parameters are trended to determine if alert levels or limits are being approached or exceeded. Instrument air is tested for moisture and other corrosive contaminants.

The Compressed Air Monitoring Program will be enhanced as follows.

- Revise Compressed Air Monitoring Program procedures to apply consideration of the guidance of ASME OM-S/G-1998 (Part 17), EPRI NP-7079, and EPRI TR-108147 to the limits specified for the air system contaminants.

- Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic visual inspections of accessible internal surfaces of system components (accumulators, flex hoses, tubing, etc.). Specify inspections at frequencies recommended in ASME OM-S/G-1998 (Part 17).

Enhancements will be implemented prior to the period of extended operation.

A.1.13 Containment Inservice Inspection – IWE

The Containment Inservice Inspection – IWE Program is implemented through plant procedures which provide administrative controls for the conduct of activities that are necessary to fulfill the requirements of 10 CFR 50.55a, which imposes the inservice inspection (ISI) requirements of the ASME B&PV Code, Section XI, Subsection IWE, for steel containments (Class MC) and steel liners for concrete containments (Class CC). There are no tendons associated with the RBS steel containment vessel (SCV). The RBS containment system is a General Electric BWR Mark III pressure suppression containment system consisting of a drywell, vapor suppression pool, and a primary containment structure. The RBS primary containment structure is a low-leakage, free-standing SCV consisting of a vertical upright cylinder with a torispherical dome and a flat liner plate at the base. The SCV forms the containment pressure boundary and encloses the vapor suppression pool and the drywell.

The program includes the SCV and its integral attachments, containment equipment hatches, airlocks, and pressure-retaining bolting. The program performs visual examinations (general visual, VT-1 and VT-3) to assess the general condition of the containment and to detect evidence of degradation that may affect structural integrity or leak tightness. The visual inspections monitor the condition of the SCV surface areas, including welds and base metal and integral attachments; personnel and equipment access hatches; and pressure-retaining bolting. Bolting is not susceptible to cracking and does not require surface or volumetric examinations to detect cracking per IWE. The Containment Inservice Inspection – IWE program specifies acceptance criteria, corrective actions, supplemental inspections as required, and provisions for expansion of the inspection scope when identified degradation exceeds the acceptance criteria. The code of record for the examination of the RBS Class MC components and related requirements is ASME Code Section XI, Subsections IWE, 2001 Edition with the 2003 Addenda, as mandated and modified by 10 CFR 50.55a.

The Containment Inservice Inspection – IWE Program will be enhanced as follows.

- Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

Enhancements will be implemented prior to the period of extended operation.

A.1.14 Containment Leak Rate

The Containment Leak Rate Program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B; RG 1.163, "Performance-Based Containment Leak-Testing Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J"; and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements." The program provides for detection of pressure boundary degradation due to aging effects such as loss of leak tightness, loss of material, cracking, or loss of sealing in various systems penetrating containment. The program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the containment pressure boundary access points.

Three types of tests are performed under Option B. Types A, B and C leakage rate testing will be implemented in accordance with the criteria set forth in RG 1.163, NEI 94-01, Revision 3-A, and the testing criteria of ANSI/ANS-56.8-2002. Type A tests are performed to determine the overall primary containment integrated leakage rate at the loss of coolant accident peak containment pressure. Performance of the integrated leakage rate test (ILRT) demonstrates the leak-tightness and structural integrity of the containment. Type B and Type C containment local leakage rate tests (LLRTs) are intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Corrective actions are taken if leakage rates exceed acceptance criteria. Test frequencies for Type A, B and C leakage rate testing comply with the requirements of 10 CFR Part 50, Appendix J, Option B based upon the criteria in NEI 94-01, Revision 3-A.

A.1.15 Diesel Fuel Monitoring

The Diesel Fuel Monitoring Program manages loss of material in piping, tanks and other components in an environment of diesel fuel oil by verifying the quality of the fuel oil source. This is performed by receipt inspection, sampling, and limiting the quantities of contaminants before allowing it to enter the fuel oil storage tanks. Parameters monitored include water and sediment content, total particulates, and levels of microbiological organisms in the fuel oil. The program includes multi-level sampling of fuel oil storage tanks. Where multi-level sampling cannot be performed due to design, a representative sample is taken from the lowest part of the tank. A stabilizer/biocide is added to new fuel.

The Diesel Fuel Monitoring Program includes periodic inspections of low flow areas where contaminants may collect such as in the bottom of tanks. The fuel oil storage tanks are periodically sampled, drained, inspected, and cleaned. Internal tank inspections for signs of moisture, contaminants, and corrosion will be performed at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Where degradation is observed, a wall thickness determination is made. Water, biological activity, and particulate concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly.

The One-Time Inspection Program (Section A.1.32) includes inspections to verify that the Diesel Fuel Monitoring Program has been effective at managing the effects of aging.

The Diesel Fuel Monitoring Program will be enhanced as follows.

- Revise Diesel Fuel Monitoring Program procedures to monitor levels of microbiological organisms in the standby diesel generator (SDG) and HPCS diesel generator fuel oil storage and day tanks, and diesel-driven fire pump fuel oil storage tanks.

- Revise Diesel Fuel Monitoring Program procedures to include periodic multi-level sampling of tanks within the scope of the program. Include provisions to obtain a representative sample from the lowest point in the tank, if tank design does not allow for multi-level sampling.

- Revise Diesel Fuel Monitoring Program procedures to include a periodic cleaning and internal visual inspection of the tanks within the program. In the areas of any degradation identified during the internal inspection, a volumetric inspection shall be performed. In the event an internal inspection cannot be performed due to design limitations, a volumetric examination shall be performed. Perform cleanings and internal inspections at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals.

- Revise Diesel Fuel Monitoring Program procedures to (a) monitor biological activity and particulate concentrations in the diesel-driven fire pump fuel oil storage tanks at least quarterly, and (b) monitor levels of microbiological organisms in the SDG and HPCS diesel fuel oil storage and day tanks at least quarterly.

Enhancements will be implemented prior to the period of extended operation.

A.1.16 Environmental Qualification (EQ) of Electric Components

The Environmental Qualification (EQ) of Electric Components Program manages the effects of thermal, radiation, and cyclic 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 are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Reanalysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. Some aging evaluations for EQ components are time-limited aging analyses (TLAAs) for license renewal.

A.1.17 External Surfaces Monitoring

The External Surfaces Monitoring Program manages aging effects of components fabricated from metallic, elastomeric, and polymeric materials through periodic visual inspection of external surfaces for evidence of loss of material, cracking, reduction of heat transfer, reduced thermal insulation resistance, and change in material properties. When appropriate for the component and material, physical manipulation, such as pressing, flexing and bending, is used to augment visual inspections to confirm the absence of elastomer hardening and loss of strength. The External Surfaces Monitoring Program is also credited for situations where the material and environment combinations are the same for the internal and external surfaces such that the external surfaces are representative of the internal surfaces.

Inspections are performed at least once every refueling cycle by personnel qualified through a plant-specific training program. Deficiencies are documented and evaluated under the corrective action program. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the component's intended functions are maintained.

Periodic visual inspections of a representative sample of in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed.

For polymeric (or non-metallic) materials, the visual inspection will include 100 percent of the accessible components. The flexible polymeric or elastomeric components that receive physical manipulation constitute at least 10 percent of the available surface area.

For stainless steel, the acceptance criterion is a clean, shiny surface. Other metals should not have abnormal surface indications. For flexible polymeric materials, a uniform surface texture (no cracks) and no change in material properties (e.g., hardness, flexibility, physical dimensions, color unchanged from when the material was new) are the acceptance criteria. For rigid polymeric materials, acceptable conditions are no surface abnormalities, such as erosion, cracking, crazing, checking, and chalking.

Thermal insulation is credited to reduce heat transfer from certain components to ensure that functions described in 10 CFR 54.4(a) are successfully accomplished. Insulation is installed in accordance with manufacturer specifications, including configuration features such as overlap and location of seams. Inspections of insulated components where the insulation is required to reduce heat transfer will be performed to ensure insulation degradation due to moisture intrusion has not occurred.

The External Surfaces Monitoring Program will be enhanced as follows.

- Revise External Surfaces Monitoring Program procedures to include instructions to perform a visual inspection of accessible flexible polymeric component surfaces. The visual inspection should identify indicators of loss of material due to wear to include dimensional change, surface cracking, crazing, scuffing, and for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. In addition, 10 percent of the available flexible polymeric surface area should receive physical manipulation to augment the visual inspection to confirm the absence of hardening and loss of strength (e.g., HVAC flexible connectors).

- Revise External Surfaces Monitoring Program procedures to specify the following for in-scope insulated components in a condensation or air – outdoor environment.

  - Periodic representative inspections will be conducted during each 10-year period during the period of extended operation.

  - For a representative sample of in-scope insulated indoor components with an environment of condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections performed that can be a combination of 1-foot axial length sections and individual components for each material type.

  - Inspection locations will be locations with a higher likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.

    - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.

    - No evidence of cracking.

  If the external visual inspections of the insulation reveal damage to its exterior surface or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

- Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on components subject to aging management review. The entire population of accessible piping component surfaces subject to aging management review that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

- Revise External Surfaces Monitoring Program procedures to include the following acceptance criteria.
  - Stainless steel should have a clean, shiny surface with no discoloration. There should be no leakage of stainless steel components in an environment of air containing halides.
  - Other metals should not have abnormal surface indications.
  - Flexible polymeric materials should have a uniform surface texture with the material in an as-new condition with no cracks, crazing, scuffing, discoloration, dimensional change, exposure of internal reinforcement for reinforced elastomers, hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate for manipulation, and no shrinkage or loss of strength.
  - Rigid polymeric materials should have no erosion, cracking, checking, or chalking.

Enhancements will be implemented prior to the period of extended operation.

A.1.18 Fatigue Monitoring

The Fatigue Monitoring Program ensures that fatigue usage remains within allowable limits for components identified to have a fatigue TLAA by (a) tracking the number of critical thermal and pressure transients for selected components, (b) verifying that the severity of monitored transients is bounded by the design transient definitions for which they are classified, and (c) assessing the impact of the reactor coolant environment on a set of sample critical components including those from NUREG/CR-6260 and those components identified to be more limiting than the components specified in NUREG/CR-6260, and (d) addressing applicable fatigue exemptions. Tracking the number of critical thermal and pressure transients for the selected components ensures a cumulative usage factor (CUF) within allowable limits, including environmental effects where applicable. The environmental effects on fatigue for the identified critical components will be evaluated.

The Fatigue Monitoring Program will be enhanced as follows.

- Revise Fatigue Monitoring Program procedures to monitor and track critical thermal and pressure transients for components with a fatigue TLAA.
- Develop a set of fatigue usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant system components. This sample shall include the locations identified in NUREG/CR-6260, additional plant-specific component locations in the reactor coolant pressure boundary if they are found more limiting than those considered in NUREG/CR-6260. Environmental correction factors (F_{en}) shall be determined using the formulae recommended in NUREG-1801, X.M1. Stress analysis methods used as inputs to fatigue analyses will consider all six stress components. An environmentally assisted fatigue analysis using NUREG/CR-6909 will not use average temperature for complex transients. For simple transients that use average temperature, when the minimum temperature is below the threshold temperature, the maximum and threshold temperature will be used to calculate the average temperature.
- Revise Fatigue Monitoring Program procedures to provide 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, an unanticipated new thermal event is discovered, or the geometry of a component has been modified.

The second enhancement on environmentally assisted fatigue usage calculations will be implemented at least two years prior to entering the period of extended operation. All other enhancements will be implemented prior to the period of extended operation.

A.1.19 Fire Protection

The Fire Protection Program manages the following through periodic visual inspection of components and structures with a fire barrier intended function.

- Carbon steel components (loss of material).
- Concrete components (cracking and loss of material).
- Masonry walls (cracking and loss of material).
- Fire resistant materials (loss of material, change in material properties, cracking/ delamination, and separation).
- Elastomer components (increased hardness, shrinkage, and loss of strength).

The Fire Protection Program manages aging effects for components that serve a fire barrier function. Fire barriers include assemblies such as penetration fire seals, walls, floors, ceilings, fire-rated doors, cable tray enclosures, cable or conduit wraps, fire stops, junction boxes, and other fire-resistant materials that serve a fire barrier intended function. Fire barrier inspections are performed at a frequency in accordance with the NRC-approved fire protection program and Technical Requirements Manual.

The periodic visual inspection and functional test of the Halon fire suppression system associated with the power generation control complex is performed to examine for signs of corrosion and degradation that may lead to the loss of material of the Halon fire suppression system. The frequency of the periodic functional test is in accordance with the NRC-approved fire protection program and the Technical Requirements Manual.

A.1.20 Fire Water System

The Fire Water System Program manages loss of material, loss of coating integrity, and flow blockage due to fouling for in-scope, long-lived, passive, water-based fire suppression system components using periodic flow testing and visual inspections in accordance with NFPA 25 (2011 Edition). In addition, the fire water system pressure is monitored such that a loss of system pressure is immediately detected and corrective action initiated. When visual inspections are used to detect loss of material and fouling, the inspection technique is capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling. The program also manages coating integrity for the fire water tanks.

Testing or replacement of sprinkler heads that have been in service for 50 years is performed in accordance with the 2011 Edition of NFPA 25. Portions of the water-based fire water system that (a) are normally dry, but periodically subject to flow (e.g., downstream of the deluge valve in a deluge system) and (b) allow water to collect are subject to augmented examination beyond that specified in NFPA 25. The augmented examinations for the portions of normally dry piping that are periodically wetted include (a) periodic full flow tests at the design pressure and flow rate, or internal inspections, and (b) volumetric wall thickness evaluations.

The training and qualification of individuals involved in fire water storage tank coating inspections are in accordance with ASTM International standards endorsed in RG 1.54, including limitations, if any, identified in RG 1.54 on a particular standard.

Program acceptance criteria include (a) the water-based fire protection system can maintain required pressure, and (b) no unacceptable signs of degradation or fouling are observed during non-intrusive or visual inspections.

In the event surface irregularities are identified, testing is performed to ensure minimum design pipe wall thickness is maintained. In the event the fire water tank fails to meet the acceptance criteria for coating or tank surface condition (e.g., peeling, delamination, blistering, flaking, cracking, or rust), the program specifies an evaluation to ensure the tank can perform its intended function until the next inspection and that downstream flow blockage is not a concern.

The Fire Water System Program will be enhanced as follows.

- Revise Fire Water System Program procedures to perform an internal inspection of the auxiliary building and diesel generator building preaction system's dry piping for loss of material every five years. Perform an inspection by removing a sprinkler from the branch line most remote from the source of water or using an inspector's test valve. In the event foreign material is found in a preaction system that could result in flow obstructions or blockage of a sprinkler head in a building, each in-scope preaction system in that building shall have an internal inspection.

- Revise Fire Water System Program procedures to perform an internal inspection every five years of the dry piping downstream of the deluge valves for the control building cable vaults (WS-6A, WS-6B and WS-6C), cable tunnel spray system (WS-8D), tunnels (WS-8E, WS-8F, WS-8G, WS-8H, WS-8K, WS-8L, WS-8M and WS-8N), and auxiliary building water curtains (WS-19 and WS-20) at 70-foot elevation and 141-foot elevation. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion product deposition and flow blockage due to fouling. In the event foreign material is found in an in-scope deluge system in a building during the five-year internal inspection of piping, the dry piping of each in-scope deluge system in that building shall have an internal inspection.

- Revise Fire Water System Program procedures to perform an internal piping inspection of every other wet fire water system every five years by opening a flushing connection at the end of one main and by removing a closed sprinkler head toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign material that could result in flow obstructions or blockage of sprinkler head or nozzles. The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a follow-up volumetric wall thickness evaluation where irregularities are detected. In the event foreign material is found, all wet pipe systems in that building shall have an internal inspection before returning to service.

- Revise Fire Water System Program procedures to perform flow testing of underground piping in accordance with NFPA 291.

- Revise Fire Water System Program procedures to inspect fire water sprinkler heads in accordance with NFPA 25, Section 5.2.1.1, with the exception of sprinkler orientation, foreign material, physical damage, and loading due to dust or debris.

- Revise Fire Water System Program procedures to inspect the interior of the fire water tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.6 and 9.2.7, including sub-steps, using the guidance of SSPC-SP2, Hand Tool Cleaning; SSPC-SP3, Power Tool Cleaning; SSPC-SP11, Cleaning of Bare Metal; and SSPC-SP WJ-1, 2, 3 and 4, Water Jet Cleaning.

- Revise Fire Water System Program procedures to remove mainline strainers, inspect for damage and corroded parts, and clean every five years, and add a requirement to flush mainline strainers (basket or screen) until clear at least once per refueling cycle if a fire water system actuation occurred or flow testing occurred during that refueling cycle.

- Revise Fire Water System Program procedures to specify that sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition), Section 5.3.1.

- Revise Fire Water System Program procedures to specify a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that allow water to collect in each five-year interval, beginning five years prior to the period of extended operation.

- Revise Fire Water System Program procedures to specify volumetric wall thickness inspections of 20 percent of the length of piping segments that allow water to collect in each five-year interval of the period of extended operation. Measurement points shall be obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically induced corrosion [MIC]). The 20 percent of piping that is inspected in each five-year interval is in different locations than previously inspected piping.

- Revise Fire Water System Program procedures to perform main drain tests on 20 percent of the standpipes and risers in accordance with NFPA 25 (2011 Edition), Sections 6.3.1.5 and 13.2.5.

- Revise Fire Water System Program procedures to specify an annual air flow test of the charcoal filter units that are in scope for license renewal. If obstructions are found, the system shall be cleaned and retested.

- Revise Fire Water System Program procedures to verify the hydrants drain within 60 minutes after flushing or flow testing.

- Revise Fire Water System Program procedures to ensure the training and qualification of the individual performing the evaluation of fire water storage tank coating degradation is in accordance with ASTM International standards endorsed in RG 1.54 guidance, including limitations, if any, identified in RG 1.54 on a particular standard.

- Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters that are not growing in size or number and are surrounded by coating bonded to the substrate as determined by a qualified coating specialist, or the following actions are performed:
  - Blistering in excess of a few small intact blisters that are not growing in size or number, or blistering not completely surrounded by coating bonded to the substrate is removed.
  - Delaminated or peeled coating is removed.
  - The exposed underlying coating is verified securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations.
  - The outermost coating is feathered, and the remaining outermost coating is determined securely bonded to the coating below at a minimum of three locations adjacent to the defective area via an adhesion test endorsed by RG 1.54.
  - Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements.
  - An evaluation is performed to ensure downstream flow blockage is not a concern.
  - A follow-up inspection is scheduled within two years and every two years after that until the coating is repaired, replaced, or removed.
- Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during visual examination.
  - Lightly tapping and scraping the coating to determine the coating integrity.
  - Dry film thickness measurements at random locations to determine overall thickness of the coating.
  - Wet-sponge testing or dry film testing to identify holidays in the coating.
  - Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations.

- Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.

- Revise Fire Water Program procedures to inspect, test and maintain pressure-reducing valves FPW-RV2A/B, FPW-RV113 and FPW-RV386 in accordance with the requirements of Chapter 13 of NFPA 25 (Refer to NFPA 25 (2011 Edition), Section 6.3.1.4).

- Revise Fire Water System Program procedures to include acceptance criteria of no abnormal debris (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Signs of abnormal corrosion or blockage will be removed, and its source and extent of condition determined and corrected. The condition will be entered into the corrective action program.

- Revise Fire Water System Program procedures to include the following acceptance criteria for the fire water tanks' interior coating:

  - Indications of peeling and delamination are not acceptable.

  - Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including limitations, if any, identified in RG 1.54 associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are not growing in number or size, and are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints").

  - Indications such as cracking, flaking, and rusting are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including limitations, if any, identified in RG 1.54 associated with use of a particular standard.

  - As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements.

  - Coating meets the plant-specific design requirements for the coating/lining and substrate for the fire water tanks.

- Revise Fire Water System Program procedures to specify replacement of sprinkler heads that show signs of leakage, excessive loading, or corrosion.

- Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist:

  - There is an obstructive discharge of material during routine flow tests.

- An inspector's test valve is clogged during routine testing.
- Foreign material is identified during internal inspections.
- Sprinkler heads are found clogged during removal or testing.
- Pin-hole leaks are identified in fire water piping.
- After an extended fire water system shutdown (greater than one year).

- Revise Fire Water System Program procedures to evaluate for MIC if tubercules or slime are identified during internal inspections of fire water piping.

Enhancements will be implemented prior to the period of extended operation.

A.1.21 Flow-Accelerated Corrosion

The Flow-Accelerated Corrosion (FAC) Program manages loss of material due to wall thinning caused by FAC for piping and components through (a) performing an analysis to determine systems susceptible to FAC, (b) conducting appropriate analysis to predict wall thinning, (c) performing wall thickness measurements based on wall thinning predictions and operating experience, and (d) evaluating measurement results to determine the remaining service life and the need for replacement or repair of components. The FAC Program relies on implementation of guidelines published by EPRI in NSAC-202L and on internal and external operating experience.

The FAC program also manages wall thinning due to various erosion mechanisms in treated water or steam systems.

The FAC Program will be enhanced as follows.

- Revise FAC Program procedures to manage wall thinning due to erosion mechanisms such as cavitation, flashing, liquid droplet impingement, and solid particle impingement.
- Revise FAC Program procedures to include susceptible locations based on the extent-of-condition reviews in response to plant-specific or industry operating experience.
- Revise FAC Program procedures to (1) evaluate wall thinning due to erosion from cavitation, flashing, liquid droplet impingement, and solid particle impingement when determining a replacement type of material, and (2) ensure piping and components replaced with FAC-resistant material and subject to erosive conditions are not excluded from inspections until effectiveness of piping replacement or other corrective action has been confirmed.

Enhancements will be implemented prior to the period of extended operation.

A.1.22 Inservice Inspection

The Inservice Inspection (ISI) Program manages cracking, loss of material, and reduction in fracture toughness for ASME Class 1, 2, and 3 pressure-retaining components including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting using periodic volumetric, surface, and visual examination and leakage testing as specified in ASME Section XI code, 2001 Edition, 2003 addendum. Additional limitations, modifications, and augmentations described in 10 CFR 50.55a are included as a part of this program. Every 10 years this program is updated to the latest ASME Section XI code edition and addendum approved by the NRC in accordance with 10 CFR 50.55a. Repair and replacement activities for these components are covered in Subsection IWA of the ASME code edition of record.

A.1.23 Inservice Inspection – IWF

The Inservice Inspection (ISI) – IWF (ISI-IWF) Program performs periodic visual examinations of ASME Class 1, 2, and 3 piping and component supports to determine general mechanical and structural condition or degradation of component supports. The examinations include verification of clearances, settings and physical displacements, and identification of loose or missing parts, debris, corrosion, wear, erosion, or the loss of integrity at welded or bolted connections. The ISI-IWF Program is implemented through plant procedures which provide administrative controls, including corrective actions, for the conduct of activities that are necessary to fulfill the requirements of ASME Section XI, as mandated by 10 CFR 50.55a. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring provides reasonable assurance that significant degradation can be identified prior to a loss of intended function.

The ISI-IWF Program includes plant procedures that use the recommendations delineated in NUREG-1339 and industry recommendations delineated in Electric Power Research Institute (EPRI) NP-5769, NP-5067 and TR-104213 to ensure proper specification of bolting material, lubricant, and installation torque.

The ISI-IWF Program will be enhanced as follows.

- Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

- Revise plant procedures to specify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts and bolts, and cracking of concrete around the anchor bolts.

- Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.

- Revise plant procedures to specify the following conditions as unacceptable:

  - Loss of material due to corrosion or wear that reduces the load bearing capacity of the component support.

  - Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support.

  - Cracked or sheared bolts, including high strength bolts, and anchors.

Enhancements will be implemented prior to the period of extended operation.

A.1.24 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program performs periodic inspections and preventive maintenance to manage loss of material due to corrosion, loose bolting or rivets, and rail wear of cranes and hoists, based on industry standards and guidance documents. The program includes structural components, including structural bolting, that make up the bridge, the trolley, lifting devices, and crane rails and includes cranes and hoists within the scope of license renewal and subject to aging management review. The activities entail visual examinations and functional testing to ensure that cranes and hoists are capable of sustaining their rated loads. The number and the magnitude of lifts made by the hoist or crane are also reviewed.

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be enhanced as follows.

- Revise plant procedures to specify that the program manages the effects of aging for the crane rails for wear; manages the effects of aging for bridge, trolley and hoists structural components for deformation, cracking, and loss of material due to corrosion; and manages the effects of aging for structural connections for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity.

- Revise plant procedures to specify inspection frequency will be in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series. The inaccessible or infrequently used cranes and hoists will be inspected prior to use. Bolted connections will be visually inspected for loose or missing bolts, nuts, pins or rivets at the same frequency as crane rails and structural components.

- Revise plant procedures to specify the acceptance criteria for 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.

- Revise plant procedures to specify that maintenance and repair activities will utilize the guidance provided in ASME B30.2 or other appropriate standard in the ASME B30 series.

Enhancements will be implemented prior to the period of extended operation.

A.1.25 Internal Surfaces in Miscellaneous Piping and Ducting Components

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages cracking, loss of material, reduction of heat transfer, and change in material properties using representative sampling and opportunistic visual inspections of the internal surfaces of metallic and elastomeric components in environments of air – indoor, air – outdoor, condensation, exhaust gas, raw water, and waste water. Internal inspections will be performed during periodic system and component surveillances or during the performance of maintenance activities when the surfaces are accessible for visual inspection.

Where practical, the inspections will focus on the bounding or leading components most susceptible to aging because of time in service and severity of operating conditions. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population will be inspected. Opportunistic inspections will continue in each period even if the minimum sample size has been inspected.

For metallic components, visual inspection will be used to detect evidence of loss of material and reduction of heat transfer. For non-metallic components, visual inspections will be used to detect surface irregularities. Visual examinations of elastomeric components will be accompanied by physical manipulation or pressurization such that changes in material properties are readily observable. The sample size for physical manipulation will be at least 10 percent of accessible surface area.

Specific acceptance criteria are as follows:

- Stainless steel: clean surfaces, shiny, no abnormal surface condition.
- Metals: no abnormal surface condition.
- Elastomers: a uniform surface texture and color with no cracks, no unanticipated dimensional change, and no abnormal surface conditions.

Conditions that do not meet the acceptance criteria are entered into the corrective action program for evaluation. Indications of relevant degradation will be evaluated using design standards, procedural requirements, current licensing basis, and industry codes or standards.

This program will be implemented prior to the period of extended operation.

A.1.26 Masonry Wall

The Masonry Wall Program is based on guidance provided in I.E. Bulletin 80-11, "Masonry Wall Design," and Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to I.E. Bulletin 80-11." The program includes masonry walls within the scope of license renewal as delineated in 10 CFR 54.4. The program manages aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation.

The program includes periodic visual inspection of masonry walls in the scope of license renewal to detect loss of material and cracking of masonry units and mortar. The aging effects that could impact a masonry wall's intended function or potentially invalidate its evaluation basis are entered in the corrective action program for further analysis, repair, or replacement. The Structures Monitoring Program (Section A.1.41) manages the effects of aging on structural steel components, such as steel edge supports and steel bracing of masonry walls.

Masonry walls are inspected at least once every five years to ensure there is no loss of intended function.

The Masonry Wall Program will be enhanced as follows.

- Revise plant procedures to ensure masonry walls located in in-scope structures are included in the scope of the Masonry Wall Program.

- Revise plant procedures to include monitoring gaps between the structural steel supports and masonry walls that could potentially affect wall qualification.

- Revise plant procedures to specify that masonry walls will be inspected at least once every five years with provisions for more frequent inspections in areas where significant aging effects (missing blocks, cracking, etc.) are observed to ensure there is no loss of intended function between inspections.

- Revise plant procedures to include acceptance criteria for masonry wall inspections that ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the wall's evaluation basis or impact its intended function.

Enhancements to this program will be implemented prior to the period of extended operation.

A.1.27 Non-EQ Electrical Cable Connections

The Non-EQ Electrical Cable Connections Program is a one-time inspection program that provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections are maintained consistent with the current licensing basis through the period of extended operation. Cable connections included are those connections susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49.

This program provides for one-time inspections that will be completed prior to the period of extended operation on a sample of connections. The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). The representative sample size will be based on 20 percent of the connection population with a maximum sample of 25.

Inspection methods may include thermography, contact resistance testing, or other appropriate quantitative test methods without removing the connection insulation, such as heat shrink tape, sleeving, or insulating boots.

The inspections will be performed prior to the period of extended operation.

A.1.28 Non-EQ Inaccessible Power Cables (≥ 400 V)

The Non-EQ Inaccessible Power Cables (≥ 400 V) Program manages the aging effect of reduced insulation resistance on the inaccessible power cable systems (≥ 400 V) that have a license renewal intended function. The program includes periodic actions to minimize inaccessible cable exposure to 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). In this program, inaccessible power cables (≥ 400 V) exposed to significant moisture are tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies are adjusted based on test results and operating experience. The specific type of test performed is a proven test for detecting deterioration of the cable insulation. A proven, commercially available test will be used for detecting deterioration of the insulation system due to wetting or submergence for inaccessible power cables (≥ 400 V) included in this program, 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.

The program includes periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspections for water after event-driven occurrences, such as flooding, will be performed. The inspections will include direct observation that cables are not wetted or submerged, that cables, splices and cable support structures are intact, and dewatering systems (i.e., sump pumps) and associated alarms, if applicable, operate properly. Inspection frequency will be increased as necessary based on evaluation of inspection results.

This program will be implemented prior to the period of extended operation.

A.1.29 Non-EQ Insulated Cables and Connections

The Non-EQ Insulated Cables and Connections Program provides reasonable assurance the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials.

Accessible insulated cables and connections within the scope of license renewal installed in an adverse localized environment will be visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. The program sample consists of all accessible cables and connections in localized adverse environments. This program sample of accessible cables will represent, with reasonable assurance, all cables and connections in the adverse localized environment.

This program will visually inspect accessible cables in an adverse localized environment at least once every 10 years, with the first inspection prior to the period of extended operation.

This program will be implemented prior to the period of extended operation.

A.1.30 Non-EQ Sensitive Instrumentation Circuits Test Review

The Non-EQ Sensitive Instrumentation Circuits Test Review Program manages the aging effects of the applicable cables in the neutron monitoring and process radiation monitoring systems or sub-systems. The program provides reasonable assurance the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture (i.e., neutron flux monitoring instrumentation and process radiation monitoring) can be maintained consistent with the current licensing basis through the period of extended operation. Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results or findings of surveillance testing programs will be performed once every 10 years, with the first review occurring before the period of extended operation.

For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least once every 10 years, with the first test occurring before the period of extended operation. Applicable industry standards and guidance documents are used to delineate the program.

This program will be implemented prior to the period of extended operation.

A.1.31 Oil Analysis

The Oil Analysis Program ensures that loss of material and reduction of heat transfer are not occurring by maintaining the quality of the lubricating oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for contaminants. The presence of water can indicate in-leakage, and particulates can be indicative of corrosion products.

The One-Time Inspection Program uses inspections or non-destructive evaluations of representative samples to verify that the Oil Analysis Program has been effective at managing the aging effects of loss of material and reduction of heat transfer.

A.1.32 One-Time Inspection

The One-Time Inspection Program consists of a one-time inspection of selected components to accomplish the following:

- Verify the effectiveness of aging management programs designed to prevent or minimize the effects of aging to the extent that they will not cause the loss of intended function during the period of extended operation. The aging effects evaluated are loss of material, cracking, and reduction of heat transfer.

- Confirm the insignificance of an aging effect using inspections that verify unacceptable degradation is not occurring.

- In the event of unacceptable inspection results, trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.

The sample size will be 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components. Identification of inspection locations will be based on the potential for the aging effect to occur. Examination techniques will be established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria will be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Any indication or relevant condition will be evaluated. The need for follow-up examinations will be evaluated based on inspection results.

The One-Time Inspection Program will not be used for structures or components with known aging mechanisms or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years.

The program will include activities to verify effectiveness of aging management programs and activities to confirm the insignificance of aging effects as described below.

Diesel Fuel Monitoring Program (Section A.1.15)	One-time inspection activity will verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling are not occurring.
Oil Analysis Program (Section A.1.31)	One-time inspection activity will verify the effectiveness of the Oil Analysis Program by confirming that unacceptable loss of material, cracking, and fouling are not occurring.
Water Chemistry Control – BWR Program (Section A.1.42)	One-time inspection activity will verify the effectiveness of the Water Chemistry Control – BWR Program by confirming that unacceptable cracking, loss of material, and fouling are not occurring.
Reactor vessel flange leak detection components	One-time inspection activity will confirm that cracking and loss of material are not occurring or are occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of RHR piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of nuclear pressure relief piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

A representative sample of internal and external surfaces of RCIC piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

Inspections will be performed within the 10 years prior to the period of extended operation.

A.1.33 One-Time Inspection – Small-Bore Piping

The One-Time Inspection – Small-Bore Piping Program augments ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and components with a nominal pipe size diameter less than 4 inches (NPS < 4) and greater than or equal to NPS 1 in systems that have not experienced cracking of ASME Code Class 1 small-bore piping. The program can also be used for systems that have experienced cracking but have implemented design changes to effectively mitigate cracking.

The program provides a one-time volumetric or opportunistic destructive inspection of a 3-percent sample or maximum of 10 ASME Class 1 piping butt weld locations and a 3-percent sample or a maximum of 10 ASME Class 1 socket weld locations that are susceptible to cracking. Volumetric examinations are performed using a demonstrated technique that is capable of detecting the aging effects in the volume of interest. In the event the opportunity arises to perform a destructive examination of an ASME Class 1 small-bore socket weld that meets the susceptibility criteria, then the program takes credit for two volumetric examinations. The program includes pipes, fittings, branch connections, and full and partial penetration welds.

This program includes a sampling approach. Sample selection is based on susceptibility to stress corrosion, cyclic loading (including thermal, mechanical, and vibration fatigue), thermal stratification, thermal turbulence, dose considerations, operating experience, and limiting locations of total population of ASME Class 1 small-bore piping locations.

The program includes measures to verify that degradation is not occurring, thereby either confirming that there are no aging effects requiring management or validating the effectiveness of any existing program for the period of extended operation. If evidence of cracking is revealed by this one-time inspection, it will be entered into the corrective action program to determine extent of condition, and a follow-up periodic inspection will be managed by a plant-specific program.

The inspection will be performed within the six years prior to the period of extended operation.

A.1.34 Periodic Surveillance and Preventive Maintenance

The Periodic Surveillance and Preventive Maintenance (PSPM) Program includes periodic inspections and tests to manage aging effects including cracking, loss of material, reduction of heat transfer, and change in material properties, in cases where no NUREG-1801 program was found appropriate to manage the particular aging effects for specific components. Indications or relevant conditions of degradation detected are evaluated. Inspections occur at least once every six years during the period of extended operation, except as noted below.

Credit for program activities has been taken in the aging management review for the following components.

- Inspect the surface of the inflatable elastomer seal for the upper containment pool gates in the reactor building.
- Inspect the surface of the inflatable elastomer seal for the spent fuel storage pool gates in the auxiliary building.
- In the plant drains system, visually inspect the internal and external surface of pump casings and piping components within sumps to manage loss of material and cracking. Visually inspect the external surface of the pump suction strainer within sumps to manage loss of material.
- In the service water system, visually inspect the external surfaces of SWC and SWP pump casings to manage loss of material.
- For the standby diesel generators, visually inspect the external surface of heat exchanger (intercooler) tube fins to manage reduction of heat transfer at least once every eight years.
- Inspect the internal surfaces of abandoned equipment in the following nonsafety-related systems affecting safety-related systems to manage loss of material:
    - Leak detection system (system code 207)
    - Makeup water system (system code 659)
    - Fuel pool cooling system (system code 602)
    - Reactor water cleanup system (system code 601)
    - Standby service water system (system code 256)
    - Process radiation monitoring system (system code 511)

- Floor and equipment drains system (system code 609)

The PSPM Program will be enhanced as follows.

- Revise PSPM Program procedures as necessary to incorporate the activities identified above.
- Revise PSPM Program procedures to state that the acceptance criterion is no indication of relevant degradation and that such indications will be evaluated.

Enhancements will be implemented prior to the period of extended operation.

A.1.35 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance Program manages the effects of aging on Service Level I coatings applied to external surfaces of carbon steel and concrete inside containment (e.g., steel containment vessel shell, structural steel, supports, penetrations, and concrete walls and floors). The program is implemented using the guidance provided in ASTM D 5163-08. The program provides an effective method to assess coating condition through visual inspections by identifying degraded or damaged coatings and providing a means for repair of identified problem areas.

Service Level I protective coatings are not credited to manage the effects of aging. Proper monitoring and maintenance of protective coatings inside containment ensures operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of Service Level I coatings ensures there is no coating degradation that would impact safety functions, for example, by clogging emergency core cooling system suction strainers.

A.1.36 Reactor Head Closure Studs

The Reactor Head Closure Studs Program manages cracking and loss of material due to wear or corrosion for reactor head closure studs bolting (studs, washers, nuts, and flange threads) using inservice inspection (ASME Section XI, 2001 Edition, 2003 Addendum, Table IWB-2500-1) and preventive measures to mitigate the effects of aging. Preventive actions include use of an acceptable surface treatment, use of stable lubricants, use of bolting materials with low susceptibility to SCC, and avoidance of the use of metal-plated stud bolting. The program detects cracks, loss of material, and leakage using visual, surface, and volumetric examinations as required by ASME Section XI. The program also relies on recommendations to address reactor head closure bolting degradation listed in NUREG-1339 and NRC RG 1.65.

The Reactor Head Closure Studs Program will be enhanced as follows.

- Revise Reactor Head Closure Studs Program procedures associated with procurement requirements to ensure replacement studs are fabricated from bolting material with actual measured yield strength less than 150 ksi.

The enhancement will be implemented prior to the period of extended operation.

A.1.37 Reactor Vessel Surveillance

The Reactor Vessel Surveillance Program manages reduction of fracture toughness and long-term operating conditions for reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F using material data and dosimetry. The program ensures that the specimen exposure, capsule withdrawal, sample testing, and capsule storage meet the requirements of 10 CFR 50, Appendix H for vessel material surveillance and American Society for Testing and Materials (ASTM) E 185.

The program provides sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) establish operating restrictions on the inlet temperature, neutron spectrum, and neutron flux after a surveillance capsule is withdrawn for testing. Surveillance capsule testing and reporting, to the extent practicable, is performed in accordance with the requirements of ASTM E 185 Standard.

The Reactor Vessel Surveillance Program has been integrated into the BWRVIP Integrated Surveillance Program (ISP). The surveillance sample materials remaining in the RBS reactor pressure vessel (RPV) are maintained for possible future use. The BWRVIP ISP replaces individual plant reactor pressure vessel surveillance capsule programs with representative weld and base materials data from host reactors. Throughout the term of the ISP, the BWRVIP monitors the progress, coordinates actions such as withdrawal and testing of capsules and reporting of surveillance capsule test results, and identifies additional program needs. The BWRVIP identifies and implements changes to the program as the need arises. When specific changes are identified to the ISP testing matrix, withdrawal schedule, or testing and reporting of individual capsule results, these modifications are submitted to the NRC in a timely manner so that appropriate arrangements can be made for implementation. RBS maintains participation in the BWRVIP ISP consistent with provisions of NUREG-1801 Section XI.M31.

The integrated surveillance program for the extended period of operation (ISP(E)), based on BWRVIP document BWRVIP-86, Revision 1-A, has been approved for use by the NRC. BWRVIP-135 provides reactor pressure vessel surveillance data and other technical material information for the plants participating in the ISP and is revised periodically as additional surveillance data is obtained.

A.1.38 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

RBS is not committed to the requirements of RG 1.127; however, the RBS RG 1.127 program was developed based on guidance provided in RG 1.127, Revision 1, and provides an inservice inspection and surveillance program for the RBS raw water-control structures associated with standby service water cooling and service water cooling systems or flood protection. The program performs periodic visual examinations to monitor the condition of water-control structures and structural components, including structural steel and structural bolting associated with water-control structures and miscellaneous steel associated with these structures. The program addresses degradation due to the effects of aging, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures. The program requires periodic monitoring and maintenance of water-control structures so that the consequences of degradation due to the effects of aging can be prevented or mitigated in a timely manner.

The program will perform periodic sampling and chemical analysis of ground water for pH, chlorides, and sulfates on a frequency of at least once every five years to ensure that the ground water has not become aggressive.

The RG 1.127 Program will be enhanced as follows.

- Revise plant procedures to include a list of structural components and commodities within the scope of license renewal to be monitored in the program.
- Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."
- Revise plant procedures to include the following parameters to be monitored or inspected:
  - For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation.
  - For chemical analysis of ground water, monitor pH, chlorides and sulfates.
  - Anchor bolts (nuts and bolts) for loss of material, and loose or missing nuts and bolts.
- Revise plant procedures to include the following requirements:

- Structures will be inspected on an interval not to exceed five years with provisions for more frequent inspections of structures and components categorized as (a)(1) in accordance with 10 CFR 50.65.

- Inspection of submerged structures at the same inspection interval and limitations as the other structures in the program.

- Sampling and chemical analysis of ground water at least once every five years. The program owner will review the results, evaluate anomalies, and trend the results.

Enhancements will be implemented prior to the period of extended operation.

A.1.39 Selective Leaching

The Selective Leaching Program demonstrates the absence of selective leaching through assessment of a sample of components (i.e., 20 percent of the population with maximum of 25 components) fabricated from gray cast iron and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum in an environment of , raw water, treated water, or soil. A population is defined as components with the same material and environment combination. Where practical, the sample will focus on components most susceptible to the effects of aging due to time in service, severity of operating condition, and lowest design margin. The program will include a one-time visual inspection of selected components coupled with hardness measurement or other mechanical examination techniques such as destructive testing, scraping, or chipping to determine whether loss of material is occurring due to selective leaching that may affect the ability of a component to perform its intended function through the period of extended operation.

For buried components with coatings, no selective leaching inspections are necessary where coating degradation has not been identified. For buried components with degraded coating or no coatings, the sample size is 20 percent of the population up to a maximum of 25 components. If only minor coating damage has been identified, the sample size may be reduced to 5 percent of the population with a maximum of 6 components. Minor coating degradation is defined as (a) there were no more than two instances of degradation identified in the 10-year period prior to the period of extended operation, and (b) the pipe could be shown to meet unreinforced opening criteria of the applicable piping code when assuming the pipe surface affected by the coating degradation is a through-wall hole.

Follow-up of unacceptable inspection findings includes an evaluation using the corrective action program and expansion of the inspection sample size and location.

This inspections will be performed within the five years prior to the period of extended operation.

A.1.40 Service Water Integrity

The Service Water Integrity Program manages loss of material and reduction of heat transfer for service water system components fabricated from carbon steel, carbon steel with copper cladding, stainless steel, and copper alloy in an environment of treated water. The program includes periodic (a) testing of the RHR heat exchangers to verify heat transfer capability, (b) inspection and maintenance of the auxiliary building unit coolers, (c) routine maintenance (cleaning) of the RHR heat exchanger radiation monitor coolers, and (d) routine maintenance (cleaning) of the penetration valve leakage control system (PVLCS) compressor aftercoolers. There are no internal coatings in components crediting the Service Water Integrity Program for managing the effects of aging.

A.1.41 Structures Monitoring

The Structures Monitoring Program manages the effects of aging on structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Inspections are performed at least once every five years to ensure that aging degradation leading to loss of intended functions will be detected and that the extent of degradation can be determined to ensure there is no loss of intended function between inspections. The scope of the Structures Monitoring Program includes structures within the scope of license renewal as delineated in 10 CFR 54.4.

The Structures Monitoring Program includes plant procedures that use the guidance delineated in NUREG-1339 and industry recommendations delineated in EPRI NP-5769, NP-5067 and TR-104213 to ensure proper specification of bolting material, lubricant, and installation torque.

The Structures Monitoring Program will be enhanced as follows.

- Revise plant procedures to include the following in-scope structures.
    - Auxiliary control building
    - Circulating water switchgear house No. 1
    - Condensate storage tank foundation
    - Electrical tunnels and piping tunnels
    - Fire protection storage tanks foundation
    - Fuel oil storage tank foundation
    - Manholes, handholes and duct banks

- Transformer and switchyard support structures and foundations

- Revise plant procedures to include a list of structural components and commodities within the scope of license renewal.

- Revise plant procedures to include periodic sampling and chemical analysis of ground water.

- Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

- Revise plant procedures to include the following parameters to be monitored or inspected:

  - For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation.

  - For chemical analysis of ground water, monitor pH, chlorides and sulfates.

- Revise plant procedures to include the following components to be monitored for the associated parameters:

  - Anchor bolts (nuts and bolts) for loss of material, and loose or missing nuts and bolts.

  - Elastomeric vibration isolators and structural sealants for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening).

- Revise plant procedures to include the following:

  - Visual inspection of elastomeric material should be supplemented by feel or touch to detect hardening if the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least 10 percent of available surface area.

  - Inspection of submerged structures at the same inspection interval and limitations as the other structures in the program.

  - Sampling and chemical analysis of ground water at least once every five years. The program owner will review the results and evaluate any anomalies and perform trending of the results.

Enhancements will be implemented prior to the period of extended operation.

A.1.42 Water Chemistry Control – BWR

The Water Chemistry Control – BWR Program manages loss of material, cracking, change in material properties, and reduction of heat transfer in components in an environment of treated water through periodic monitoring and control of water chemistry. The Water Chemistry Control – BWR Program monitors and controls chemical species and water quality to keep levels of various contaminants below system-specific limits. BWRVIP-190, BWR Water Chemistry Guidelines, Revision 1, is used to provide guidance for the program.

The One-Time Inspection Program (Section A.1.32) uses inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR Program has been effective at managing aging effects. The representative sample includes low flow and stagnant areas.

A.1.43 Water Chemistry Control – Closed Treated Water Systems

The Water Chemistry Control – Closed Treated Water Systems Program manages loss of material, cracking, and reduction of heat transfer in components in a closed treated water environment through monitoring and control of water chemistry, including the use of corrosion inhibitors, chemical testing, and visual inspections of internal surfaces. The EPRI Closed Cooling Water Guideline (1007820), industry and site operating experience, and vendor recommendations are used to delineate the program.

The Water Chemistry Control – Closed Treated Water Systems Program will be enhanced as follows.

- Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to inspect accessible components whenever a closed treated water system boundary is opened. Ensure that a representative sample of piping and components is inspected at a frequency of at least once every 10 years. These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection guidance by qualified personnel using procedures that are capable of detecting loss of material, reduction of heat transfer, or cracking.

  If visual examination identifies adverse conditions, then additional examinations, including ultrasonic testing, are conducted. Components inspected will be those with the highest likelihood of corrosion, reduction of heat transfer due to fouling, or cracking. A representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. Components inspected will be those with the highest likelihood of loss of material, reduction of heat transfer, or cracking.

- Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to provide acceptance criteria for inspections of accessible components. Ensure system components meet system design requirements, such as minimum wall thickness.

Enhancements will be implemented prior to the period of extended operation.

A.2 EVALUATION OF TIME-LIMITED AGING ANALYSES

In accordance with 10 CFR 54.21(c), an application for a renewed license requires an evaluation of time-limited aging analyses for the period of extended operation. The following time-limited aging analyses were evaluated as part of the license renewal application to meet this requirement.

A.2.1 Reactor Vessel Neutron Embrittlement

The regulations governing reactor vessel integrity are in 10 CFR 50. Section 50.60 requires that light-water reactors meet the fracture toughness, pressure-temperature limits, and material surveillance program requirements for the reactor coolant pressure boundary set forth in Appendices G and H of 10 CFR 50. The RBS analyses that address the effects of neutron irradiation embrittlement on the reactor vessel for 40 years are TLAAs and either have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) or will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii) as summarized below. Based on the plant operating history, 54 effective full power years (EFPY) is used to bound the expected EFPY.

A.2.1.1 Reactor Vessel Fluence

Fluence is calculated based on a time-limited assumption defined by the operating term. Therefore, analyses that evaluate reactor vessel neutron embrittlement based on calculated fluence are TLAAs. The neutron fluence values for the RBS reactor pressure vessel beltline materials (plates, welds, and nozzles) have been projected to 54 EFPY of operation.

The predicted peak high energy (> 1 million electron-volts [MeV]) neutron fluence for 54 EFPY is 8.35E+18 neutrons per square centimeter (n/cm^2) at the vessel inner surface. Neutron fluence for the welds, shells and nozzles of the RPV beltline region was determined using the General Electric Hitachi (GEH) method for neutron flux calculation documented in report NEDC-32983P-A and approved by the NRC. This GEH method adheres to the guidance provided in RG 1.190.

The calculation of fluence is treated as a TLAA that has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) and used as an input to the analyses in the following sections.

A.2.1.2 Adjusted Reference Temperature

A key parameter that characterizes the fracture toughness of a material is the reference nil-ductility transition temperature (RT_{NDT}). The effects of neutron radiation on RT_{NDT} are reflected in the reference temperature change (ΔRT_{NDT}). The adjusted reference temperature (ART) is calculated by adding ΔRT_{NDT} to initial RT_{NDT} with an appropriate margin for uncertainties (RT_{NDT} + ΔRT_{NDT} + margin) as defined by RG 1.99, Revision 2.

The ART values for all beltline materials are calculated using fluence values determined with an NRC-approved method that complies with RG 1.190. Axial weld heat 5P6756/Linde 124 in Shell #2 is the limiting material with an ART of 110.7°F.

The TLAA for adjusted reference temperatures has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). Formal revisions of affected analyses are completed as part of the established process for generation of updated P-T operating limits under the Reactor Vessel Surveillance Program (Section A.1.37).

A.2.1.3 Pressure-Temperature Limits

Appendix G of 10 CFR 50 requires that the reactor vessel remain within established pressure-temperature (P-T) limits. These limits are calculated using fluence and materials data, including data obtained through the Reactor Vessel Surveillance Program (Section A.1.37).

The P-T limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50, assuring that limits remain valid through the period of extended operation.

The effects of aging associated with the P-T limits will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.1.4 Upper Shelf Energy

Upper shelf energy (USE) is evaluated for beltline materials. Fracture toughness criteria in 10 CFR 50 Appendix G require that beltline materials maintain USE no less than 50 ft-lb during operation of the reactor unless it is demonstrated that lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. The 54 EFPY USE values for the beltline materials were determined using methods consistent with RG 1.99, Revision 2. The value of peak ¼T fluence was used. The results of the evaluation demonstrate that all beltline materials meet the 10 CFR 50 Appendix G criteria through 54 EFPY.

The time-limited aging analysis for USE has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.1.5 Reactor Vessel Circumferential Weld Inspection Relief

Relief from reactor vessel circumferential weld inservice inspection (ISI) examination requirements was granted by the NRC. The reactor vessel circumferential weld inspection relief for the period of extended operation will be submitted to the NRC in accordance with 10 CFR 50.55(a). The effects of aging associated with the time-limited aging analysis for reactor vessel circumferential weld inspection relief will be managed in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.1.6 Reactor Vessel Axial Weld Failure Probability

The NRC safety evaluation report (SER) for BWRVIP-74-A evaluated the failure frequency of axially oriented welds in BWR reactor vessels. Applicants for license renewal must evaluate axially oriented RPV welds to show that their failure frequency remains below the value calculated in the BWRVIP-74 SER. The SER states that an acceptable way to do this is to show that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in the SER.

The projected 54 EFPY RBS mean RT_{NDT} values are less than the 32 EFPY mean RT_{NDT} provided by the NRC SER for BWRVIP-05. The reactor vessel axial weld failure probability TLAA has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.1.7 Reactor Pressure Vessel Core Reflood Thermal Shock Analysis

General Electric Report NEDO-10029 is referenced in USAR Section 5.3. NEDO-10029 addressed the concern for brittle fracture of the reactor pressure vessel due to reflood following a postulated loss of coolant accident (LOCA). The thermal shock analysis documented in the report assumed a design basis LOCA followed by a low pressure coolant injection (LPCI), accounting for the effects of neutron embrittlement at the end of 40 years. Because this analysis bounded only 40 years of operation, reflood thermal shock of the reactor pressure vessel has been identified as a TLAA requiring evaluation for the period of extended operation.

A later analysis of the BWR vessels was developed in 1979 (Ranganath, S., "Fracture Mechanics Evaluation of a Boiling Water Reactor Vessel Following a Postulated Loss of Coolant Accident," Fifth International Conference on Structural Mechanics in Reactor Technology, Berlin, Germany, August 1979 (Accession No. 9110110105 in NRC ADAMS Public Legacy Library)). The Ranganath analysis has been used to evaluate the TLAA through the period of extended operation because it evaluates the bounding LOCA event for a BWR-6 vessel design, which is a main steam line break.

The maximum ART value calculated for the RBS RPV beltline material is 110.7°F. Using the equation for fracture toughness K_{IC} presented in Appendix A of ASME Section XI and the maximum ART value, the material reaches upper shelf at 215°F, which is well below the minimum 380°F temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the revised analysis has projected the TLAA through the period of extended operation. The reactor pressure vessel core reflood thermal shock TLAA has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.2 Metal Fatigue

A.2.2.1 Class 1 Metal Fatigue

Fatigue evaluations were performed in the design of RBS Class 1 components in accordance with their design requirements. ASME Section III fatigue evaluations are contained in analyses and stress reports, and because they are based on a number of transient cycles assumed for a 40-year operating term, these evaluations are considered TLAA.

RBS utilizes cycle counting, cycle-based fatigue monitoring, and stress-based fatigue monitoring. The Fatigue Monitoring Program (Section A.1.18) tracks and evaluates transient cycles and requires corrective actions if limits are approached. The Fatigue Monitoring Program ensures that the numbers of transient cycles experienced by the plant remain within the numbers of cycles assumed in the fatigue analysis.

The following provides additional information for specific Class 1 components.

<u>Reactor Pressure Vessel</u>

As described in USAR Section 5.3.3.1 and shown in USAR Figure 5.3-1, the reactor pressure vessel is a vertical, cylindrical pressure vessel of welded construction.

Stress-based fatigue analyses are used for monitoring the RBS feedwater nozzles. The transients necessary to track to ensure the continuing validity of fatigue analyses for other RPV locations have been identified. The Fatigue Monitoring Program (Section A.1.18) will manage the effects of aging due to fatigue on the reactor vessel in accordance with 10 CFR 54.21(c)(1)(iii).

<u>Reactor Pressure Vessel Internals</u>

For reactor vessel internals components with fatigue TLAAs, the effects of aging due to fatigue will be managed by the BWR Vessel Internals Program (Section A.1.10) for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The program performs inspections and flaw evaluations in accordance with the guidelines of applicable BWRVIP reports. This program manages the aging effects of cracking, loss of preload, loss of material, and reduction in fracture toughness for BWR vessel internal components in a reactor coolant environment.

<u>Reactor Recirculation Pumps</u>

As described in USAR Section 3.9.3.1.6B, the recirculation pumps are designed in accordance with the ASME Code, Section III, considering the transients identified in USAR Section 3.9.1.1.11B.

Transient cycles are monitored in accordance with the Fatigue Monitoring Program (Section A.1.18), which assures that action is taken if the accrued number of cycles of a transient approaches the analyzed number of cycles. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the reactor recirculation pumps in accordance with 10 CFR 54.21(c)(1)(iii).

Control Rod Drives

The Class 1 portions of the control rod drives were analyzed for fatigue. Transient cycles are monitored using the Fatigue Monitoring Program (Section A.1.18), which assures that action is taken if the accrued number of cycles of a transient approaches the analyzed number of cycles. As such, the Fatigue Monitoring Program will manage the effects of aging due to fatigue on the control rod drives in accordance with 10 CFR 54.21(c)(1)(iii).

Class 1 Piping and In-Line Components

Detailed fatigue analyses were generated to analyze multiple locations within the ASME Class 1 boundary on each system. The Fatigue Monitoring Program (Section A.1.18) will monitor the accrued cycles and utilize cycle-based fatigue monitoring and stress-based fatigue monitoring. The Fatigue Monitoring Program will manage the effects of aging due to fatigue on the ASME Section III piping in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.2.2 Non-Class 1 Fatigue

The non-Class 1 fatigue screening document in Appendix H of the EPRI Mechanical Tools was used to determine locations susceptible to fatigue cracking in non-Class 1 systems at RBS. The first step in the screening process was to identify non-Class 1 components that may have normal or upset condition operating temperature in excess of 220°F for carbon steel or 270°F for stainless steel. Components that were identified in the appropriate aging management reviews as above the threshold for fatigue are further evaluated for fatigue in the following sections. The components identified for fatigue are grouped into one of the two major categories of (1) piping and in-line components (tubing, piping, traps, thermowells, valve bodies, etc.) or (2) non-piping components (tanks, vessels, heat exchangers, pump casings, turbine casings, expansion joints, etc.)

Piping and In-Line Components

The impact of thermal cycles on non-Class 1 components is addressed in the calculation of the allowable stress range. The design of ASME III Code Class 2 and 3 or ANSI B31.1 piping systems incorporates a stress range reduction factor for piping design with respect to thermal stresses. In general, a stress range reduction factor of 1.0 in the stress analyses applies for up to 7,000 thermal cycles. The allowable stress range is reduced by the stress range reduction factor if the number of thermal cycles exceeds 7,000.

Thermal cycles for the non-Class 1 systems have been evaluated for 60 years of plant operation. For many plant systems, significant temperature cycles are coincident with plant heatups and cooldowns, which are limited to well below 7,000 cycles. Systems with transients that are independent of plant heatups and cooldowns (e.g., SRV actuations, component surveillance testing) have been evaluated, and 7,000 thermal cycles will not be exceeded for 60 years of operation. Therefore, the non-Class 1 piping and in-line components stress calculations remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Non-Piping Components

The ECCS suction strainers were evaluated for loadings from the SRV operation and earthquake cycles as part of the design. The allowable number of cycles was far in excess of anticipated cycles. Therefore, these analyses for strainers are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Design specifications and calculations for metal flex hoses and expansion joints were identified with fatigue analyses for a bounding number of cycles, which were identified as TLAAs. Evaluation of the analyses for each of these systems determined the number of analyzed cycles was adequate for 60 years of operation. Therefore, these metal flex hose and expansion joint fatigue TLAAs remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A.2.2.3 Effects of Reactor Water Environment on Fatigue Life

NUREG/CR-6260 addresses the application of environmental correction factors to fatigue analyses (CUFs) and identifies locations of interest for consideration of environmental effects. Section 5.6 of NUREG/CR-6260 identified the following component locations to be the most sensitive to environmental effects for newer vintage General Electric plants. These locations are directly relevant to RBS.

(1) Reactor vessel shell and lower head

(2) Reactor vessel feedwater nozzle

(3) Reactor recirculation piping (including inlet and outlet nozzles)

(4) Core spray line reactor vessel nozzle and associated Class 1 piping

(5) Residual heat removal nozzles and associated Class 1 piping

(6) Feedwater line Class 1 piping

The Fatigue Monitoring Program includes an enhancement to complete the environmentally assisted fatigue evaluation (see Section A.1.18). The Fatigue Monitoring Program will manage the effects of aging due to fatigue, including environmentally assisted fatigue, for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.3 Environmental Qualification of Electrical Components

All operating plants must meet the requirements of 10 CFR 50.49, which defines the scope of electrical components to be included in an EQ program and also provides the requirements an EQ program must meet. Qualification is established for the environmental and service conditions during normal plant operation and also those conditions postulated for plant accidents. A record of qualification for in-scope components must be prepared and maintained in auditable form. Equipment qualification evaluations for EQ components that result in a qualification of at least 40 years, but less than 60 years, are considered TLAAs for license renewal.

The RBS Environmental Qualification of Electric Components Program (EQ Program, Section A.1.16) manages component thermal, radiation, and cyclical aging, as applicable, through 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 to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. The RBS EQ Program ensures that the EQ components are maintained in accordance with their qualification bases.

The RBS EQ Program implements RBS commitments for 10 CFR 50.49. The program is consistent with NUREG-1801, Section X.E1, "Environmental Qualification (EQ) of Electric Components." The RBS EQ Program will manage the effects of aging on the intended function(s) of EQ components that are the subject of EQ TLAAs for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.4 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis

RBS utilizes a BWR Mark III containment. As described in USAR Section 3.8.2.4.1, fatigue analysis requirements for the steel containment cylinder and dome are evaluated in accordance with the requirements of ASME B&PV Code Section III, Division I, Subsection NE. Fatigue analysis requirements for the floor liner plate are evaluated in accordance with the requirements of ASME B&PV Code, Section III, Division 2. Further review of the containment dynamic loading effects are contained in USAR Appendix 6A.

The containment penetrations are described in USAR Section 3.8.2.1.2. The piping penetrations consist of sleeved penetrations for high temperature piping and unsleeved penetrations for low temperature piping. Detailed fatigue calculations were generated for the containment penetrations at RBS. The pipe and flued heads of the penetrations are evaluated as part of the piping pressure boundary. Critical locations of the penetration within the ASME Code Class MC boundary were evaluated for fatigue. The electrical penetrations were evaluated, and stresses were found to be so low that fatigue analysis was not required.

Containment structural components including the personnel airlocks, polar crane, equipment hatch, drywell airlock, drywell combination door/hatch assembly, and drywell head were evaluated for fatigue. The normal and upset loading conditions considered for fatigue of the primary containment components include earthquakes and effects from safety/relief valve (SRV) lifts. Loads that would occur during an accident such as a loss of coolant accident or main steam line break were also evaluated.

As shown on USAR Figure 3.8-4, expansion joints (bellows) are utilized on sleeved penetrations. The specification required these be qualified for 14,000 cycles due to pipe thermal loads, 500 operating basis earthquake (OBE) cycles, and 20,000 SRV lift cycles. Plant startups, OBE cycles, and SRV cycles are tracked, and the associated systems will not exceed 7000 cycles. Therefore, the analyses for the bellows are adequate for the period of extended operation.

As shown in USAR Figures 3.8-8 and 9.1-20, bellows are utilized on the fuel transfer tube. As shown in USAR Figure 9.1-20 and USAR Table 9.1-3, the upper bellows are safety-related. This bellows is designed for seismic events that are tracked (none have occurred) and 150 cycles of flexing (some of which occur during the installation of the fuel transfer tube blind flange).

RBS will manage the aging effects due to fatigue for the containment components using the Fatigue Monitoring Program (Section A.1.18) in accordance with 10 CFR 54.21(c)(1)(iii).

A.2.5 Other Plant-Specific TLAAs

A.2.5.1 Erosion of Main Steam Line Flow Restrictors

USAR Section 5.4.4.4 states that flow restrictors erode very slowly and conservatively postulates that even with an erosion rate of 0.004 inches per year, the increase in choked flow after 40 years would be no more than 5 percent.

Entergy evaluated the erosion rate for the main steam flow restrictors. The evaluation considered the specific material for the flow restrictors and determined the expected erosion rate. The evaluation determined the expected erosion rate would be much less than the conservative value in the USAR. Using the lower expected corrosion rate, the increase in flow restrictor diameter after 60 years would result in a choked flow increase of less than the 5 percent value identified as acceptable in USAR Section 5.4.4.4.

This analysis has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.5.2 Postulation of High Energy Line Break (HELB) Locations

USAR Section 3.6.2.1.5.1A indicates that the determination of intermediate high energy line break (HELB) locations relied on an evaluation of cumulative usage factors (CUFs). As long as other stress criteria were also met, a break is not postulated at a location if the CUF is less than 0.1.

The Fatigue Monitoring Program (Section A.1.18) will identify if the numbers of cycles are approaching the analyzed numbers of cycles. If the cycle limit will be exceeded, the program requires a review of the design calculations based on an assumed cycle limit to determine the necessary corrective actions.

Therefore, the fatigue calculations used for determining the intermediate HELB locations are evaluated in accordance with 10 CFR 54.21(c)(1)(iii). The Fatigue Monitoring Program (Section A.1.18) will manage the associated effects of aging.

A.2.5.3 Fluence Effects for Reactor Vessel Internals

The design specification for the reactor vessel internals components includes requirements beyond the ASME design requirements for austenitic stainless steel base metal components exposed to greater than 1×10^{21} nvt (> 1 MEV) or weld metal exposed to greater than 5×10^{20} nvt (> 1 MEV), where *nvt* equals neutron density (*n*) multiplied by neutron velocity (*v*), multiplied by time (*t*).

The effects of fluence for 60 years of operation (54 EFPY) were analyzed for the reactor vessel internals components included in the design specification. Location-specific fluence levels were determined. The internal core support structure components were then evaluated against the fluence criteria in the design specification. The evaluation determined that the RBS internal core support structure components meet the design specification for operating conditions through 54 EFPY.

Therefore, this analysis has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

A.2.5.4 Crane Load Cycles Analysis

Cranes that were designed to Crane Manufacturer's Association of America Specification #70 (CMAA-70) have an expected range of lifting cycles specified as part of their design. While there is no analysis that involves time-limited assumptions defined by the current operating term, for example, 40 years, fatigue evaluations are nevertheless evaluated as TLAAs for cranes that were designed to CMAA-70.

A review of the cranes at RBS was performed to determine which cranes were designed to CMAA-70. The spent fuel cask trolley crane and reactor building polar crane included CMAA-70 Service Class A1 in their design specification. The fuel building bridge crane includes CMAA-70 Service Class B in its design specification. The number of load cycles for which a crane is qualified under CMAA-70 Service Class A1 and B is based on load class and load cycles. The minimum range is 20,000 to 100,000 cycles.

The total estimated number of lifts for each of these cranes (spent fuel cask trolley crane, fuel building bridge crane, and reactor building polar crane) is well below 100,000 cycles. Therefore, the expected number of lifts is well below the value specified in CMAA-70, and the crane fatigue evaluation remains valid for the period of extended operation consistent with 10 CFR 54.21(c)(1)(i).

A.3 REFERENCES

A.3-1 [RBS License Renewal Application—later]

A.3-2 [NRC Safety Evaluation Report for RBS License Renewal—later]

A.4 LICENSE RENEWAL COMMITMENT LIST

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
1	Aboveground Metallic Tanks	Implement the Aboveground Metallic Tanks Program as described in LRA Section A.1.1.	Prior to February 28, 2025.	RBG-47735
2	Bolting Integrity	Enhance the Bolting Integrity Program as described in LRA Section A.1.2.	Prior to February 28, 2025.	RBG-47735
3	Boraflex Monitoring	Enhance the Boraflex Monitoring Program as described in LRA Section A.1.3.	Prior to February 28, 2025.	RBG-47735
4	Buried and Underground Piping and Tanks Inspection	Implement the Buried and Underground Piping and Tanks Inspection Program as described in LRA Section A.1.4.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
5	BWR Vessel Internals	Enhance the BWR Vessel Internals Program as described in LRA Section A.1.10.	Prior to February 28, 2025. Initial inspections will be performed prior to August 29, 2030.	RBG-47735
6	Coating Integrity	Implement the Coating Integrity Program as described in LRA Section A.1.11.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
7	Compressed Air Monitoring	Enhance the Compressed Air Monitoring Program as described in LRA Section A.1.12.	Prior to February 28, 2025.	RBG-47735
8	Containment Inservice Inspection – IWE	Enhance the CII-IWE Program as described in LRA Section A.1.13.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
9	Diesel Fuel Monitoring	Enhance the Diesel Fuel Monitoring Program as described in LRA Section A.1.15.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
10	External Surfaces Monitoring	Enhance the External Surfaces Monitoring Program as described in LRA Section A.1.17.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
11	Fatigue Monitoring	Enhance the Fatigue Monitoring Program as described in LRA Section A.1.18.	Enhancement to develop a set of fatigue usage calculations: prior to August 29, 2023. Remaining enhancements: prior to February 28, 2025.	RBG-47735
12	Fire Water System	Enhance the Fire Water System Program as described in LRA Section A.1.20.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
13	Flow-Accelerated Corrosion	Enhance the Flow-Accelerated Corrosion Program as described in LRA Section A.1.21.	Prior to February 28, 2025.	RBG-47735
14	Inservice Inspection – IWF	Enhance the ISI-IWF Program as described in LRA Section A.1.23.	Prior to February 28, 2025.	RBG-47735
15	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program as described in LRA Section A.1.24.	Prior to February 28, 2025.	RBG-47735
16	Internal Surfaces in Miscellaneous Piping and Ducting Components	Implement the Internal Surfaces in Miscellaneous Piping and Ducting Components Program as described in LRA Section A.1.25.	Prior to February 28, 2025.	RBG-47735

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
17	Masonry Wall	Enhance the Masonry Wall Program as described in LRA Section A.1.26.	Prior to February 28, 2025.	RBG-47735
18	Non-EQ Electrical Cable Connections	Implement the Non-EQ Electrical Cable Connections Program as described in LRA Section A.1.27.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
19	Non-EQ Inaccessible Power Cables (≥ 400 V)	Implement the Non-EQ Inaccessible Power Cables (≥ 400 V) Program as described in LRA Section A.1.28.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
20	Non-EQ Insulated Cables and Connections	Implement the Non-EQ Insulated Cables and Connections Program as described in LRA Section A.1.29.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
21	Non-EQ Sensitive Instrumentation Circuits Test Review	Implement the Non-EQ Sensitive Instrumentation Circuits Test Review Program as described in LRA Section A.1.30.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
22	One-Time Inspection	Implement the One-Time Inspection Program as described in LRA Section A.1.32.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
23	One-Time Inspection – Small-Bore Piping	Implement the One-Time Inspection – Small-Bore Piping Program as described in LRA Section A.1.33.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
24	Periodic Surveillance and Preventive Maintenance	Enhance the PSPM Program as described in LRA Section A.1.34.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
25	Reactor Head Closure Studs	Enhance the Reactor Head Closure Studs Program as described in LRA Section A.1.36.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735

No.	Program or Activity	Commitment	Implementation Schedule	Source (Letter Number)
26	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program as described in LRA Section A.1.38.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
27	Selective Leaching	Implement the Selective Leaching Program as described in LRA Section A.1.39.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
28	Structures Monitoring	Enhance the Structures Monitoring Program as described in LRA Section A.1.41.	Prior to February 28, 2025, or the end of the last refueling outage prior to August 29, 2025, whichever is later.	RBG-47735
29	Water Chemistry Control – Closed Treated Water Systems	Enhance the Water Chemistry Control – Closed Treated Water Systems Program as described in LRA Section A.1.43.	Prior to February 28, 2025.	RBG-47735

Appendix B

Aging Management Programs and Activities

River Bend Station
License Renewal Application

TABLE OF CONTENTS

B.0 INTRODUCTION

B.0.1 OVERVIEW

The aging management review results for the integrated plant assessment of RBS are presented in Sections 3.1 through 3.6 of this application. The programs credited in the integrated plant assessment for managing the effects of aging are described in this appendix.

Each aging management program described in this appendix has 10 elements in accordance with the guidance in NUREG-1800 (Ref. B.2-1) Appendix A.1, "Aging Management Review – Generic," Table A.1-1, "Elements of an Aging Management Program for License Renewal." For aging management programs that are comparable to the programs described in Sections X and XI of NUREG-1801 (Ref. B.2-2), *Generic Aging Lessons Learned (GALL) Report*, the 10 elements have been compared to the elements of the NUREG-1801 program and relevant ISGs (see Section 2.1.3). For the plant-specific program that does not correlate with NUREG-1801, the 10 elements are addressed in the program description.

B.0.2 FORMAT OF PRESENTATION

For those aging management programs that are comparable to the programs described in Sections X and XI of NUREG-1801, the program discussion is presented in the following format.

- **Program Description**: abstract of the overall program as it will exist when fully implemented.
- **NUREG-1801 Consistency**: summary of the degree of consistency between the RBS program and the corresponding NUREG-1801 program, when applicable.
- **Exceptions to NUREG-1801**: exceptions to the NUREG-1801 program, including a justification for the exceptions, when applicable.
- **Enhancements**: future program enhancements with a proposed schedule for their completion, when applicable.
- **Operating Experience**: discussion of operating experience information specific to the program.
- **Conclusion**: statement of reasonable assurance that the program is effective, or will be effective, once implemented with necessary enhancements.

For the plant-specific program, a complete discussion of the 10 elements of NUREG-1800 Table A.1-1 is provided.

B.0.3 CORRECTIVE ACTIONS, CONFIRMATION PROCESS AND ADMINISTRATIVE CONTROLS

Three elements common to all aging management programs are corrective actions, confirmation process, and administrative controls. Discussion of these elements is presented below. Corrective actions have program-specific details which are included in the descriptions of the individual programs in this report, but further discussion of the confirmation process and administrative controls is not included in the descriptions of the individual programs.

Corrective Actions

Conditions adverse to quality—such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances—are promptly identified and corrected. In the case of significant conditions adverse to quality, measures are implemented to ensure that the cause of the condition is determined and that corrective action is taken to preclude recurrence. The root cause of the significant condition adverse to quality and the corrective action implemented are documented and reported to appropriate levels of management. The corrective action controls of the RBS quality assurance (QA) program (10 CFR Part 50, Appendix B) are applicable to all aging management programs and activities through the period of extended operation. The RBS corrective actions are consistent with NUREG-1801.

Confirmation Process

RBS QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The RBS QA program applies to safety-related and important-to-safety structures and components. Corrective actions and administrative (document) control for both safety-related and nonsafety-related structures and components are accomplished in accordance with the existing RBS corrective action program and document control program. The confirmation process is part of the corrective action program and includes the following:

- Reviews to assure that corrective actions are adequate.
- Tracking and reporting of open corrective actions.
- Review of corrective action effectiveness.

Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program. The corrective action program constitutes the confirmation process for aging management programs and activities. The RBS confirmation process is consistent with NUREG-1801.

Administrative Controls

RBS QA procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. The RBS QA program applies to RBS safety-related and augmented activities on plant structures, systems and components. Administrative (document) control for both safety-related and nonsafety-related structures and components is accomplished per the existing document control program. The RBS administrative controls are consistent with NUREG-1801.

B.0.4 OPERATING EXPERIENCE

Site-specific operating experience for at least 10 years was reviewed for the programs and activities credited with managing the effects of aging. The corrective action program was used to identify condition reports related to the effectiveness of aging management programs by using keywords as search tools for finding documented issues with the programs. Thus the review included corrective actions that resulted in program enhancements. For inspection programs, reports of recent inspections, examinations, or tests were reviewed to determine if aging effects have been identified on applicable components. For monitoring programs, condition reports in the corrective action program are initiated if parameters are found outside of program specifications. Also, program owners contributed evidence of program success or weakness and identified applicable self-assessments, QA audits, peer evaluations, and NRC reviews.

Operating experience from plant-specific and industry sources is identified and systematically reviewed on an ongoing basis. The RBS corrective action program, which is implemented in accordance with the quality assurance program, effects the documentation and evaluation of plant-specific operating experience. The RBS operating experience program, which meets the provisions of NUREG-0737, Item I.C.5, “Procedures for Feedback of Operating Experience to Plant Staff,” systematically evaluates industry operating experience. The operating experience program includes active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.

In accordance with these programs, site-specific and industry operating experience items are screened to determine whether they involve lessons learned that may impact aging management programs (AMPs). Items are evaluated, and affected AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined that the effects of aging are not adequately managed. Plant-specific operating experience associated with managing the effects of aging is reported to the industry in accordance with guidelines established in the operating experience review program.

Training provided for personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience, as well as for personnel responsible for implementing AMPs, is based on the complexity of the job performance requirements and assigned responsibilities. Training is scheduled on a recurring basis, which accommodates the turnover of plant personnel and the need for new training content.

B.0.5 AGING MANAGEMENT PROGRAMS

Table B-1 lists the aging management programs described in this appendix. Programs are identified as either existing or new. The programs are either comparable to programs described in NUREG-1801 or are plant-specific. The correlation between NUREG-1801 programs and RBS programs is discussed in Section B.0.6.

Table B-1
Aging Management Programs

Program	Section	New or Existing
Aboveground Metallic Tanks	B.1.1	New
Bolting Integrity	B.1.2	Existing
Boraflex Monitoring	B.1.3	Existing
Buried and Underground Piping and Tanks Inspection	B.1.4	New
BWR CRD Return Line Nozzle	B.1.5	Existing
BWR Feedwater Nozzle	B.1.6	Existing
BWR Penetrations	B.1.7	Existing
BWR Stress Corrosion Cracking	B.1.8	Existing
BWR Vessel ID Attachment Welds	B.1.9	Existing
BWR Vessel Internals	B.1.10	Existing
Coating Integrity	B.1.11	New
Compressed Air Monitoring	B.1.12	Existing
Containment Inservice Inspection – IWE	B.1.13	Existing
Containment Leak Rate	B.1.14	Existing
Diesel Fuel Monitoring	B.1.15	Existing
Environmental Qualification (EQ) of Electric Components	B.1.16	Existing
External Surfaces Monitoring	B.1.17	Existing
Fatigue Monitoring	B.1.18	Existing
Fire Protection	B.1.19	Existing
Fire Water System	B.1.20	Existing
Flow-Accelerated Corrosion	B.1.21	Existing

Table B-1 (Continued)
Aging Management Programs

Program	Section	New or Existing
Inservice Inspection	B.1.22	Existing
Inservice Inspection – IWF	B.1.23	Existing
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	B.1.24	Existing
Internal Surfaces in Miscellaneous Piping and Ducting Components	B.1.25	New
Masonry Wall	B.1.26	Existing
Non-EQ Electrical Cable Connections	B.1.27	New
Non-EQ Inaccessible Power Cable ($\geq$ 400 V)	B.1.28	New
Non-EQ Insulated Cables and Connections	B.1.29	New
Non-EQ Sensitive Instrumentation Circuits Test Review	B.1.30	New
Oil Analysis	B.1.31	Existing
One-Time Inspection	B.1.32	New
One-Time Inspection – Small-Bore Piping	B.1.33	New
Periodic Surveillance and Preventive Maintenance	B.1.34	Existing
Protective Coating Monitoring and Maintenance	B.1.35	Existing
Reactor Head Closure Studs	B.1.36	Existing
Reactor Vessel Surveillance	B.1.37	Existing
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	B.1.38	Existing
Selective Leaching	B.1.39	New
Service Water Integrity	B.1.40	Existing
Structures Monitoring	B.1.41	Existing
Water Chemistry Control – BWR	B.1.42	Existing
Water Chemistry Control – Closed Treated Water Systems	B.1.43	Existing

B.0.6 CORRELATION WITH NUREG-1801 AGING MANAGEMENT PROGRAMS

The correlation between NUREG-1801 programs and RBS programs is shown in Table B-2. For the RBS programs, links to appropriate sections of this appendix are provided. Table B-3 summarizes the consistency of RBS programs with NUREG-1801 programs.

Table B-2
RBS Aging Management Program Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	RBS Program
X.E1	Environmental Qualification (EQ) of Electric Components	Environmental Qualification (EQ) of Electric Components [B.1.16]
X.M1	Fatigue Monitoring	Fatigue Monitoring [B.1.18]
X.S1	Concrete Containment Tendon Prestress	RBS does not have pre-stressed tendons in the containment structure. This NUREG-1801 program does not apply.
XI.M1	ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Inservice Inspection [B.1.22]
XI.M2	Water Chemistry	Water Chemistry Control – BWR [B.1.42]
XI.M3	Reactor Head Closure Stud Bolting	Reactor Head Closure Studs [B.1.36]
XI.M4	BWR Vessel ID Attachment Welds	BWR Vessel ID Attachment Welds [B.1.9]
XI.M5	BWR Feedwater Nozzle	BWR Feedwater Nozzle [B.1.6]
XI.M6	BWR Control Rod Drive Return Line Nozzle	BWR CRD Return Line Nozzle [B.1.5]
XI.M7	BWR Stress Corrosion Cracking	BWR Stress Corrosion Cracking [B.1.8]
XI.M8	BWR Penetrations	BWR Penetrations [B.1.7]
XI.M9	BWR Vessel Internals	BWR Vessel Internals [B.1.10]

Table B-2 (Continued)
RBS Aging Management Program Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	RBS Program
XI.M10	Boric Acid Corrosion	RBS is a BWR. This NUREG-1801 program does not apply.
XI.M11B	Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs only)	RBS is a BWR. This NUREG-1801 program does not apply.
XI.M12	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	This NUREG-1801 program is not credited for aging management. RCS piping components do not meet the susceptibility criteria of XI.M12.
XI.M16A	PWR Vessel Internals	RBS is a BWR. This NUREG-1801 program does not apply.
XI.M17	Flow-Accelerated Corrosion	Flow-Accelerated Corrosion [B.1.21]
XI.M18	Bolting Integrity	Bolting Integrity [B.1.2]
XI.M19	Steam Generators	RBS is a BWR. This NUREG-1801 program does not apply.
XI.M20	Open-Cycle Cooling Water System	Service Water Integrity [B.1.40]
XI.M21A	Closed Treated Water Systems	Water Chemistry Control – Closed Treated Water Systems [B.1.43]
XI.M22	Boraflex Monitoring	Boraflex Monitoring [B.1.3]
XI.M23	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems [B.1.24].
XI.M24	Compressed Air Monitoring	Compressed Air Monitoring [B.1.12]

Table B-2 (Continued)
RBS Aging Management Program Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	RBS Program
XI.M25	BWR Reactor Water Cleanup System	Not credited for aging management. Refer to relevant discussion in Table 3.3.1, Item 3.3.1-16.
XI.M26	Fire Protection	Fire Protection [B.1.19]
XI.M27	Fire Water System	Fire Water System [B.1.20]
XI.M29	Aboveground Metallic Tanks	Aboveground Metallic Tanks [B.1.1]
XI.M30	Fuel Oil Chemistry	Diesel Fuel Monitoring [B.1.15]
XI.M31	Reactor Vessel Surveillance	Reactor Vessel Surveillance [B.1.37]
XI.M32	One-Time Inspection	One-Time Inspection [B.1.32]
XI.M33	Selective Leaching	Selective Leaching [B.1.39]
XI.M35	One-Time Inspection of ASME Code Class 1 Small-Bore Piping	One-Time Inspection – Small-Bore Piping [B.1.33]
XI.M36	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring [B.1.17]
XI.M37	Flux Thimble Tube Inspection	RBS is a BWR. This NUREG-1801 program does not apply.
XI.M38	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Internal Surfaces in Miscellaneous Piping and Ducting Components [B.1.25]
XI.M39	Lubricating Oil Analysis	Oil Analysis [B.1.31]
XI.M40	Monitoring of Neutron-Absorbing Materials Other than Boraflex	This program is not in use at RBS.
XI.M41	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks Inspection [B.1.4]

Table B-2 (Continued)
RBS Aging Management Program Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	RBS Program
XI.E1	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Non-EQ Insulated Cables and Connections [B.1.29]
XI.E2	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Non-EQ Sensitive Instrumentation Circuits Test Review [B.1.30]
XI.E3	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Non-EQ Inaccessible Power Cables (≥ 400 V) [B.1.28]
XI.E4	Metal Enclosed Bus	Not credited for aging management. Metal enclosed bus (MEB) does not have a license renewal intended function at RBS. Refer to relevant discussion in Table 3.6.1, Item 3.6.1-11.
XI.E5	Fuse Holders	Not credited for aging management. Refer to relevant discussion in Table 3.6.1, Items 3.6.1-16 and 3.6.1-17.
XI.E6	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Non-EQ Electrical Cable Connections [B.1.27]
XI.S1	ASME Section XI, Subsection IWE	Containment Inservice Inspection — IWE [B.1.13]

Table B-2 (Continued)
RBS Aging Management Program Correlation with NUREG-1801 Programs

NUREG-1801 Number	NUREG-1801 Program	RBS Program
XI.S2	ASME Section XI, Subsection IWL	RBS does not have a Class CC concrete containment that requires an IWL program. This NUREG-1801 program does not apply.
XI.S3	ASME Section XI, Subsection IWF	Inservice Inspection – IWF [B.1.23]
XI.S4	10 CFR 50, Appendix J	Containment Leak Rate [B.1.14]
XI.S5	Masonry Walls	Masonry Wall [B.1.26]
XI.S6	Structures Monitoring	Structures Monitoring [B.1.41]
XI.S7	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants [B.1.38]
XI.S8	Protective Coating Monitoring and Maintenance	Protective Coating Monitoring and Maintenance [B.1.35]
Plant-Specific Programs		
NA	Plant-specific program	Periodic Surveillance and Preventive Maintenance [B.1.34]

Table B-3
RBS Program Consistency with NUREG-1801

Program Name	Plant-Specific	NUREG-1801 Comparison: Program has Enhancements	NUREG-1801 Comparison: Program has Exceptions to NUREG-1801
Aboveground Metallic Tanks [B.1.1]			
Bolting Integrity [B.1.2]		X	X
Boraflex Monitoring [B.1.3]		X	
Buried and Underground Piping and Tanks Inspection [B.1.4]			
BWR CRD Return Line Nozzle [B.1.5]			
BWR Feedwater Nozzle [B.1.6]			
BWR Penetrations [B.1.7]			
BWR Stress Corrosion Cracking [B.1.8]			
BWR Vessel ID Attachment Welds [B.1.9]			
BWR Vessel Internals [B.1.10]		X	
Coating Integrity [B.1.11]			
Compressed Air Monitoring [B.1.12]		X	X
Containment Inservice Inspection – IWE [B.1.13]		X	
Containment Leak Rate [B.1.14]			X
Diesel Fuel Monitoring [B.1.15]		X	
Environmental Qualification (EQ) of Electric Components [B.1.16]			
External Surfaces Monitoring [B.1.17]		X	
Fatigue Monitoring [B.1.18]		X	
Fire Protection [B.1.19]			

Table B-3 (Continued)
RBS Program Consistency with NUREG-1801

Program Name	Plant-Specific	NUREG-1801 Comparison: Program has Enhancements	NUREG-1801 Comparison: Program has Exceptions to NUREG-1801
Fire Water System [B.1.20]		X	X
Flow-Accelerated Corrosion [B.1.21]		X	
Inservice Inspection [B.1.22]			
Inservice Inspection – IWF [B.1.23]		X	
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems [B.1.24]		X	
Internal Surfaces in Miscellaneous Piping and Ducting Components [B.1.25]			
Masonry Wall [B.1.26]		X	
Non-EQ Electrical Cable Connections [B.1.27]			
Non-EQ Inaccessible Power Cables (≥ 400 V) [B.1.28]			
Non-EQ Insulated Cables and Connections [B.1.29]			
Non-EQ Sensitive Instrumentation Circuits Test Review [B.1.30]			
Oil Analysis [B.1.31]			
One-Time Inspection [B.1.32]			
One-Time Inspection – Small-Bore Piping [B.1.33]			
Periodic Surveillance and Preventive Maintenance [B.1.34]	X		

Table B-3 (Continued)
RBS Program Consistency with NUREG-1801

Program Name	Plant-Specific	NUREG-1801 Comparison: Program has Enhancements	NUREG-1801 Comparison: Program has Exceptions to NUREG-1801
Protective Coating Monitoring and Maintenance [B.1.35]			
Reactor Head Closure Studs [B.1.36]		X	X
Reactor Vessel Surveillance [B.1.37]			X
RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants [B.1.38]		X	
Selective Leaching [B.1.39]			
Service Water Integrity [B.1.40]			
Structures Monitoring [B.1.41]		X	
Water Chemistry Control – BWR [B.1.42]			
Water Chemistry Control – Closed Treated Water Systems [B.1.43]		X	

B.1 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

B.1.1 ABOVEGROUND METALLIC TANKS

Program Description

The Aboveground Metallic Tanks Program is a new program that will manage loss of material for the nonsafety-related aluminum condensate storage tank (CST), which is located outdoors on sand and concrete. Preventive measures to mitigate corrosion were applied during construction, such as using the appropriate materials and use of a protective multi-layer vapor barrier beneath the tank. The inner volume of the concrete ring foundation is filled with clean dry sand, which is sloped downward from the tank center to the tank exterior. The protective multi-layer vapor barrier beneath the tank serves as a seal at the concrete-to-tank interface. There are no indoor tanks included in this program.

Interior and exterior surfaces of the CST will be inspected. The program will also perform ultrasonic testing (UT) of the CST tank bottom to assess the thickness against the design specified thickness whenever the tank is drained or during each 10-year period starting 10 years before the period of extended operation.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Aboveground Metallic Tanks Program will be consistent with the program described in NUREG-1801, Section XI.M29, Aboveground Metallic Tanks, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Aboveground Metallic Tanks Program is a new program. Industry operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

Although the Aboveground Metallic Tanks Program is a new program, RBS has in place basic elements of the program, such as routine inspections performed to industry standards, deficiency identification processes, and corrective actions.

A review of RBS operating experience for tank inspections did not identify any occurrences of loss of material for the CST.

The Aboveground Metallic Tanks Program will be consistent with the program described in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Aboveground Metallic Tanks Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.2 BOLTING INTEGRITY

Program Description

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for pressure-retaining closure bolting using preventive measures and inspection activities. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program includes the inspection activities required by ASME Section XI for ASME Class 1, 2 and 3 pressure-retaining bolting. For ASME Class 1, 2 and 3 bolting and non-ASME Code class bolts, periodic system inspections (at least once per refueling cycle) ensure identification of indications of loss of preload, cracking, and loss of material before leakage becomes excessive. Submerged pressure-retaining bolting will be inspected at least once every 10 years.

In addition to periodic visual inspections with components in service, visual inspection of bolting heads, nuts and threads is performed on a representative sample of closure bolting during each 10-year interval of the period of extended operation. If the number of opportunistic inspections is insufficient, the program will provide for additional directed inspections necessary to achieve a sample of 20 percent of the population (for each material/environment combination) up to a maximum of 25 bolts during each 10-year interval of the period of extended operation.

Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, were used to develop the program implementing procedures. The Structures Monitoring Program (Section B.1.41) manages the aging effects on structural bolting.

The preventive measures of the Bolting Integrity Program manage loss of preload for buried fire water system bolting, which is inspected under the Buried and Underground Piping and Tanks Inspection Program (Section B.1.4).

NUREG-1801 Consistency

The Bolting Integrity Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M18, Bolting Integrity, with exceptions.

Exceptions to NUREG-1801

The Bolting Integrity Program has the following exceptions.

Element Affected	Exception
4. Detection of Aging Effects	NUREG-1801 recommends periodic inspections of bolting for leakage, loss of preload, and cracking. Opportunistic inspections are performed for buried fire water system bolting in lieu of periodic inspections.[1]
4. Detection of Aging Effects	NUREG-1801 recommends periodic inspection of pressure-retaining bolting for loss of material, loss of preload, and cracking at a frequency of at least once every refueling cycle. Submerged pressure-retaining bolting will be inspected at least once every 10 years.[2]

Bases for Exceptions

1. The Bolting Integrity Program manages loss of preload for buried fire water system bolting using preventive measures implemented before burial, specifically, verifying correct material, checking for uniform gasket compression after assembly, applying protective coating, and applying an appropriate preload. These measures have proven effective in managing loss of preload for buried fire water system bolting. Opportunistic inspection of buried fire water system bolting is performed such as in conjunction with excavations performed for the Buried and Underground Piping and Tanks Inspection Program (Section B.1.4).

2. The visual inspection of accessible surfaces of suppression pool suction strainer submerged bolting at least once every 10 years is appropriate because the bolts are fabricated from stainless steel, are subject to a treated water environment, and are either torqued at installation in accordance with manufacturer specification or have the bolts/nuts lock-wired together. These bolting inspections will include visual inspection of the bolt heads, nuts, and threaded bolt shank beyond the nut, where accessible. The frequency is consistent with ASME Section XI, Table IWB 2500-1, Examination Categories B-G-1 and B-G-2 which specify visual examination of pressure-retaining bolts at least once each 10-year ISI interval.

   Other submerged pressure-retaining bolting is associated with pumps that are periodically removed and inspected during maintenance. Maintenance activities provide for bolting visual inspections at a frequency sufficient to detect aging effects prior to loss of intended function.

   For submerged bolting that is periodically inspected by divers, physically verifying that the bolting is hand tight is effective in managing loss of preload, and visual inspection of accessible bolting surfaces is appropriate for managing loss of material. (cont.)

All normally submerged pressure-retaining bolting will be inspected at least once every 10 years. These measures have proven effective in managing loss of material, cracking, and loss of preload for normally submerged pressure-retaining bolting.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise Bolting Integrity Program procedures to include submerged closure bolting for pressure-retaining components.
4. Detection of Aging Effects	Revise Bolting Integrity Program procedures to volumetrically examine high-strength bolting (regardless of code classification) (i.e., bolting with actual yield strength greater than or equal to 150 ksi) for cracking in accordance with ASME Section XI, Table IWB-2500-1, Examination Category B-G-1.
4. Detection of Aging Effects	Revise Bolting Integrity Program documents to specify visual inspection of a representative sample of closure bolting (bolt heads, nuts, and threads) in air environments. A representative sample will be 20 percent of the population (for each material/environment combination) up to a maximum of 25 fasteners during each 10-year period of the period of extended operation. The inspections will be performed when the bolting is removed to the extent that the bolting threads and bolt heads are accessible for inspections that cannot be performed during visual inspection with the threaded fastener installed.

Operating Experience

The following examples of operating experience provide objective evidence that the Bolting Integrity Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2010, while performing a standby service water quarterly pump and valve operability test, an operator noticed three detensioned bolts on a pipe flange. No leaks were noted at this flange. The condition was addressed using normal work processes.

- In 2010, during the Division II emergency diesel generator maintenance outage, a turbocharger bolt was found broken prior to turbocharger disassembly, and two bolts broke during turbocharger replacement and post-maintenance testing. The cause of the broken bolts was determined to be high cycle fatigue caused by vibration of the intake air pipe. Corrective actions included replacement of all 10 turbocharger bracket bolts, installation of damper struts on the intake piping to reduce vibration, and revisions to the turbocharger preventive maintenance process to re-torque the turbocharger mounting bolts every 3 years and to replace the mounting bolts when the turbocharger is replaced.

- In 2011, loosened turbocharger exhaust outlet bolts were found during hot torque work in preparation for the Division II standby diesel generator surveillance. Loosened bolts in this location had been determined to only result in minor exhaust leakage, well within the capabilities of the room exhaust fan. The turbocharger exhaust outlet bolts were hot torqued to 30 ft-lb. No changes to the preventive maintenance procedure were necessary.

- In 2012, during the performance of the pre-inspection runs for the Division I standby diesel outage, a bolt on the exhaust shroud brackets was identified as sheared. The broken bolt was one of 27 that secure the exhaust manifold to the engine. The missing bolt was judged to have no impact on the ability of the exhaust manifold structure to perform its design intended function. The remainder of the bolt was removed, and a new bolt was installed in its place.

- In 2012, a visual examination of a containment electrical penetration found all accessible bolting acceptable.

- In 2013, during an inspection of suction strainers in the suppression pool, one bolt was found not tight on a LPCS strainer. Maintenance properly torqued the one loose bolt on the LPCS strainer. The torque of the remaining bolts on the LPCS strainer and all bolts on the HPCS strainer was acceptable.

- In 2014, a broken or missing bolt was reported on the Division II diesel cam shaft cover. There was no impact on diesel operability. The work order to remove the cam shaft cover included a step to replace any broken or damaged cam shaft cover bolts.

- In 2015, deficiencies of studs and nuts, primarily bad threads, were found on safety relief valves that were being replaced. Actions to resolve the fastening issue were added to the work order.

- In 2015, a visual examination of CRD hatch bolting (22 studs, 2 bolts, 46 nuts and 46 washers) found the bolting components in acceptable condition. Slight galling was noted at the center of the studs, outside of the thread engagement area.

As discussed in element 10 to NUREG-1801, Section XI.M18, this program considers the technical information and industry operating experience provided in NRC IE Bulletin 82-02 and NRC Generic Letter (GL) 91-17.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the Bolting Integrity Program has been effective. The continued application of proven methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Bolting Integrity Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.3 BORAFLEX MONITORING

Program Description

The Boraflex Monitoring Program manages reduction in neutron-absorbing capacity and change in material properties in the Boraflex material affixed to spent fuel racks. A monitoring program for the Boraflex panels in the spent fuel storage racks is implemented to assure that degradation of the Boraflex material does not compromise the criticality analysis in support of the design of spent fuel storage racks. The program uses the RACKLIFE predictive computer code or equivalent to calculate the gamma dose absorbed by and the amount of boron carbide loss from the Boraflex panels.

The program entails (a) periodic sampling and analysis for silica levels in the spent fuel pool water and trending the results using the RACKLIFE code or equivalent, (b) performing periodic physical measurements of test coupons containing Boraflex material that have been located in the spent fuel pool, and (c) areal B-10 density measurement testing of the spent fuel storage racks, such as BADGER testing, at a frequency of not less than once every five years. This program assures that the required 5 percent sub-criticality margin is maintained.

NUREG-1801 Consistency

The Boraflex Monitoring Program, with enhancement, will be consistent with the program described in NUREG-1801, Section XI.M22, Boraflex Monitoring.

Exceptions to NUREG-1801

None

Enhancements

The following enhancement will be implemented prior to the period of extended operation.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Boraflex Monitoring Program procedures to include areal B-10 density measurement testing of the spent fuel storage racks, such as BADGER testing, at a frequency of at least once every five years.

Operating Experience

The following operating experience provides objective evidence that the Boraflex Monitoring Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis during the period of extended operation while Boraflex is credited for neutron absorption in the spent fuel pool.

- In 2004, on-site testing was performed on a Boraflex coupon from the spent fuel pool with acceptable results.
- In 2011, long-term Boraflex coupon holder A4 with coupons 1-3 was removed from the spent fuel pool for on-site testing and found acceptable.
- In 2011, a condition was identified with a missing reference document listed in the spent fuel pool coupon surveillance program procedure and with how the coupon test evaluation uses the data from measurements of the length and thickness of the coupon. The reference document was found and sent to records. The program procedure was revised to add acceptance criteria based on the SFP criticality analysis assumptions of Boraflex length and thickness from EPRI Report NP-6159, "An Assessment of Boraflex Performance in Spent-Nuclear-Fuel Storage Racks," and a discussion of the basis of the new acceptance criteria was also included.
- In 2012, a condition was identified with the criticality safety analysis (CSA) for the spent fuel pool (SFP) and the rate of degradation of Boraflex in the pool. Further analysis determined that the uncertainties associated with the existing information impacted the margin available to credit the Boraflex neutron absorber for long-term storage. Sufficient margin existed in the current CSA to bound the Boraflex degradation for more than seven years from the 2015 refueling outage. A project was initiated to determine an appropriate action plan to address the SFP Boraflex.
- In 2014, long-term Boraflex coupon A-5 was removed from the spent fuel pool for on-site testing and found acceptable.

As discussed in element 10 to NUREG-1801, Section XI.M22, this program considers the technical information and industry operating experience provided in NRC Information Notice (IN) 87-43, IN 93-70, IN 95-38, and NRC GL 96-04.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the Boraflex Monitoring Program has been effective. The continued application of proven monitoring methods provides reasonable assurance that the effects of aging will be managed such that neutron-absorbing components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Boraflex Monitoring Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.4 BURIED AND UNDERGROUND PIPING AND TANKS INSPECTION

Program Description

The Buried and Underground Piping and Tanks Inspection Program is a new program that will manage the effects of aging on external surfaces of buried piping components and tanks subject to aging management review. Components included in the program are fabricated from metallic materials. The program will manage loss of material and cracking through preventive and mitigative features (e.g., coatings, backfill quality, and cathodic protection) and periodic inspection activities during opportunistic and directed excavations. The number of inspections is based on the availability and effectiveness of preventive and mitigative actions. Annual cathodic protection surveys are conducted. For steel components, where the acceptance criteria for effectiveness of cathodic protection is other than -850 mV instant off, loss of material rates are measured.

Inspections are conducted by qualified individuals. Where the coatings, backfill, or condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. If a lack of soil corrosivity as determined by soil testing is used as a basis for a reduction in the number of inspections, then soil testing is conducted at least once in each 10-year period starting 10 years prior to the period of extended operation.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M41, Buried and Underground Piping and Tanks, as modified by LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tanks Recommendations."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following discussion provides objective evidence that the Buried and Underground Piping and Tanks Inspection Program, when fully established, will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation. Industry operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

The Buried and Underground Piping and Tanks Inspection Program is a new program to be implemented at RBS. Buried piping inspection activities have begun at RBS in response to industry initiatives on ground water protection and buried piping integrity. The inspections performed to date have been under the RBS program initiated in accordance with NEI 09-14.

A review of RBS operating experience for buried or underground piping or tanks identified the following.

- In November 2012, a visual inspection was performed on buried high pressure core spray piping. The inspection found that the coating was missing on areas of the pipe. This condition was apparently caused by the excavation process. There were no visible areas of corrosion or pitting in the areas with missing coating.
- In December 2012, a visual inspection was performed on buried pipe lines in the condensate makeup, storage and transfer system (CNS), liquid radwaste system (LWS), and instrument air system (IAS). The inspections found that coating was missing on areas of stainless steel pipe (CNS and LWS). The condition was apparently caused by the excavation process. There were no visible areas of corrosion or pitting in areas with missing coating.
- A program health report from the fourth quarter of 2015 states that overall the program is acceptable. Cathodic protection system maintenance has been performed, but rectifiers are problematic. Underground piping has been ranked by risk and inspections scheduled accordingly. Inspections of underground piping containing radioactive material were completed by December 31, 2014, which was the due date in NEI 09-14, Revision 3. The inspections completed revealed sound piping with only minor coating degradation.
- A program health report from the second quarter of 2016 states that overall the program is acceptable. The condition of the cathodic protection system was improved from the previous health reporting period.

The Buried Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, as modified by LR-ISG-2015-01, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Buried and Underground Piping and Tanks Inspection Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.5 BWR CRD RETURN LINE NOZZLE

Program Description

The BWR Control Rod Drive (CRD) Return Line Nozzle Program manages cracking of the CRD return line (CRDRL) reactor pressure vessel nozzle using preventive, mitigative, and inservice inspection activities. The CRDRL nozzle, which is exposed to a reactor coolant environment, was capped during construction prior to plant operation. This examination program originated through NUREG-0619 but is now governed by ASME Code, Section XI. Therefore, augmented inspections specified by NUREG-0619 are not applicable. The CRDRL nozzle inner radius is volumetrically examined to monitor the effects of cracking in accordance with the ASME Code, Section XI as part of the ISI Program. The examination is performed at least once each ISI interval. The scope of the program includes the CRDRL nozzle, the nozzle-to-reactor vessel weld, the CRDRL nozzle cap, and the Inconel end cap to carbon steel safe end dissimilar metal weld. The nozzle, cap, and associated welds are included in the visual inspection (VT-2) during the reactor pressure test performed after each refueling outage.

Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI, IWB-3512. Repair and replacement are in accordance with the requirements of ASME Section XI, IWA-4000.

NUREG-1801 Consistency

The BWR CRD Return Line Nozzle Program is consistent with the program described in NUREG-1801, Section XI.M6, BWR Control Rod Drive Return Line Nozzle.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following discussion provides objective evidence that the BWR CRD Return Line Nozzle Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

RBS cut and capped the CRD return line nozzle during construction prior to initial operations to mitigate fatigue cracking. Inservice inspection (ISI) examinations continue to monitor crack initiation and growth on the control rod drive return line nozzle and cap N10. The nozzle inner radius is scheduled for examination once each interval. The nozzle, cap and associated welds are included in the visual inspection (VT-2) during the reactor pressure test performed each refueling outage. The safe end cap weldment has been treated with the mechanical stress improvement process (MSIP) to reduce the susceptibility to intergranular stress corrosion cracking.

The review of plant-specific operating experience found no conditions involving degradation of the N10 CRD nozzle. The absence of adverse site-specific operating experience is further indication that the program has been effective.

The CRD Return Line Nozzle Program detects aging effects using nondestructive examination (NDE) visual and volumetric techniques to detect and characterize flaws. These techniques are widely used and have been demonstrated effective at detecting aging effects during inspections performed to meet ASME Section XI Code requirements. The continued application of these proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The BWR CRD Return Line Nozzle Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.6 BWR FEEDWATER NOZZLE

Program Description

The BWR Feedwater Nozzle Program manages cracking due to cyclic loading on the reactor vessel's four feedwater nozzles using periodic inspection activities. Volumetric examination of the feedwater nozzle inner radii is performed in accordance with ASME Code, Section XI, Examination Category B-D. The inspections are performed at least once each ISI interval. Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI, IWB-3512. This examination program originated through NUREG-0619 but is now governed by ASME Code, Section XI.

NUREG-1801 Consistency

The BWR Feedwater Nozzle Program is consistent with the program described in NUREG-1801, Section XI.M5, BWR Feedwater Nozzle.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following discussion provides objective evidence that the BWR Feedwater Nozzle Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- During a 1991 power ascension with single loop recirculation pump operation, a drop in feedwater temperature occurred due to a failed high level dump valve on a feedwater heater. The resulting temperature transient was evaluated for its effect on the feedwater nozzles. The feedwater temperature loss was determined to be bounded by analyzed values, and the fatigue usage factor for the feedwater nozzle was determined to be less than the allowable limit of 1.0.

- During the March 1989 ISI inspection of the nozzle-to-safe end weld on the N4A feedwater nozzle, a reportable indication was detected. Analysis was performed to confirm the acceptability of continued operation through Cycle 3 (September 1990). A mid-cycle outage in March 1990 during Cycle 3 found no growth from the 1989 examination outside standard accuracy tolerances.

During the Cycle 3 refueling outage in November 1990, the feedwater nozzle was again inspected to determine the size of the crack. Evaluation determined that it would be safe to continue operation with the increased crack size until the next refueling outage, with a commitment to perform NDE of the crack at a mid-cycle outage. The results of the mid-cycle inspection determined that the crack dimensions had increased. However, the data showed that the crack growth rate was below the earlier predicted value. River Bend could safely operate with the cracked weld to the end of the Cycle 4 because the final flaw dimensions would not exceed the ASME Code allowable.

During the refueling outage for Cycle 4 in 1992, the N4A nozzle-to-safe end weld was reexamined. The weld was cut out and replaced with a weld that is not susceptible to IGSCC. The work included removing all Inconel buttering and replacing the safe-end piston-ring style thermal sleeve with a tuning fork style.

- During the 2008 refueling outage for Cycle 14, UT exams were performed on three N4 feedwater nozzle-to-safe end welds. No indications were found that required evaluation in accordance with ASME Section XI.
- During the 2011 refueling outage for Cycle 16, UT exams were performed on three N4 feedwater nozzle-to-safe end welds. No indications were found that required evaluation in accordance with ASME Section XI.

As discussed in element 10 of NUREG-1801, Section XI.M5, this program considers the technical information and industry operating experience provided in NUREG-0619 and NRC GL 81-11.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the BWR Feedwater Nozzle Program has been effective at managing the aging effect of cracking of carbon steel feedwater nozzles. The continued application of proven inspection methods provides assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The BWR Feedwater Nozzle Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.7 BWR PENETRATIONS

Program Description

The BWR Penetrations Program manages cracking due to cyclic loading or stress corrosion cracking (SCC) and intergranular SSC (IGSCC) of BWR instrument penetrations, CRD housing and incore housing penetrations, and core plate differential pressure (ΔP)/standby liquid control penetrations. The program is implemented through station procedures that provide for mitigation of cracking through management of water chemistry and condition monitoring through examinations of reactor vessel penetration welds.

Inspections are performed in accordance with the guidelines of BWRVIP-49-A for the instrument penetrations, BWRVIP-47-A for the CRD housing and incore housing penetrations, and BWRVIP-27-A for the core plate ΔP/standby liquid control penetrations. The guidelines of BWRVIP-49-A, BWRVIP-47-A, and BWRVIP-27-A provide information on the type of penetrations, evaluate their susceptibility and consequences of failure, and define the inspection strategy to assure safe operation. During each refueling outage, a visual inspection (VT-2) of the instrument penetrations, CRD housing and incore housing penetrations, and core plate ΔP/standby liquid control penetrations are performed during the reactor coolant pressure boundary system leakage test. These BWRVIP guidelines also provide details on evaluation of flaws, expansion of scope as required, and acceptance criteria.

NUREG-1801 Consistency

The BWR Penetrations Program is consistent with the program described in NUREG-1801, Section XI.M8, BWR Penetrations.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following discussion provides objective evidence that the BWR Penetrations Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- Instrument Penetrations

  RBS has performed VT-2 inspections as part of the ISI program. There have been no pressure boundary failures identified. No repairs have been performed on the instrument penetrations.

- Core Plate ΔP/Standby Liquid Control Penetration

  Inspection history: In 2004, 2006, 2007, 2009, 2011 and 2013, RBS performed an Enhanced VT-2 for penetration N11. This inspection was performed by gaining access under the vessel during the Class 1 pressure test. No leakage was observed. No indications have been identified on the standby liquid control nozzle.

- In 2009, the Tennessee Valley Authority identified a reactor coolant pressure boundary through-wall crack in the base material adjacent to the safe end of a reactor vessel instrumentation nozzle at Browns Ferry. The RBS evaluation identified 14 RBS reactor vessel nozzles potentially affected.

  The ΔP/standby liquid control penetrations (N11, N18 [Core ΔP instrumentation]) were determined to have similar materials, fabrication techniques and configurations to the nozzles in the subject operating experience. However, these nozzles are exempted from volumetric and surface examination due to inaccessibility caused by adjacent CRD penetrations. Therefore, examination methods other than the enhanced visual VT-2 examination performed in accordance with the BWRVIP-49-A guidance are not feasible at RBS. RBS is continuing to perform the enhanced visual VT-2 examination of the N11 and N18 nozzles.

  The remaining 12 nozzles were determined not susceptible to the mechanism described in the report on the Browns Ferry condition due to differences in materials, fabrication techniques and configuration.

The inspection results and review of industry operating experience demonstrate that the BWR Penetrations Program has been effective. The continued application of these proven inspection methods provides assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

<u>Conclusion</u>

The BWR Penetrations Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.8 BWR STRESS CORROSION CRACKING

Program Description

The BWR Stress Corrosion Cracking Program manages IGSCC in stainless steel, cast austenitic stainless steel (CASS), and nickel alloy reactor coolant pressure boundary piping and piping welds 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93°C (200°F) during power operation regardless of code classification.

Reactor coolant water chemistry is controlled and monitored in accordance with EPRI guidelines to maintain high water purity and reduce susceptibility to IGSCC as described in the Water Chemistry Control – BWR Program (Section B.1.42) . Hydrogen water chemistry and noble metals chemical application have been implemented to further reduce IGSCC susceptibility of the reactor coolant piping systems.

The program addresses the management of crack initiation and growth due to IGSCC in the reactor coolant piping, welds, and components through the implementation of the ISI Program in accordance with ASME Code, Section XI. Inservice inspections performed as augmented examinations of the Section XI ISI Program ensure that aging effects are identified and repaired before the component's loss of intended function.

The inspection frequency for welds classified as Category C is in accordance with the recommendations provided in the staff-approved BWRVIP-75-A. Welds classified as Category A are subsumed into the risk-informed inservice inspection (RI-ISI) program in accordance with the June 30, 2010, NRC safety evaluation that approved RI-ISI at RBS. During the period of extended operation, at least 10 percent of the Category A welds are inspected during each ISI interval. RBS has only Category A and C welds. The program includes preventive measures including the mechanical stress improvement process (MSIP) to minimize stress corrosion cracking.

Scheduled volumetric examinations provide timely detection of IGSCC and leakage of coolant in accordance with the methods, inspection guidelines, and flaw evaluation criteria delineated in the ASME Code; NUREG-0313, Revision 2; NRC GL 88-01 and its Supplement 1; staff-approved BWRVIP-75-A; and other requirements specified per 10 CFR 50.55a with NRC-approved alternatives.

Inspection and flaw evaluations are conducted in accordance with the ISI Program. Flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI, IWB-3514. In the event IGSCC flaws are identified exceeding the acceptance criteria of IWB-3500, the NRC is notified as required by GL 88-01.

NUREG-1801 Consistency

The BWR Stress Corrosion Cracking Program is consistent with the program described in NUREG-1801, Section XI.M7, BWR Stress Corrosion Cracking.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

No plant-specific aging management program issues have been identified for RBS. A review of Owners Acceptance Reports since the 2006 refueling outage identified no items in the scope of this program with flaws or relevant conditions requiring evaluation in accordance with ASME Section XI.

As discussed in element 10 of NUREG-1801, Section XI.M7, this program considers the technical information and industry operating experience provided in GL 88-01, IN 82-39, IN 84-41, IN 04-08, NUREG-0313 (Rev. 2), and in the staff-approved BWRVIP-75-A report.

The continued application of proven methods provides assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The BWR Stress Corrosion Cracking Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.9 BWR VESSEL ID ATTACHMENT WELDS

Program Description

The BWR Vessel ID [inside diameter] Attachment Welds Program manages cracking in structural welds for BWR reactor vessel internal integral attachments. The program is implemented through station procedures that provide for mitigation of cracking of reactor vessel internal components through control of reactor water chemistry as described in the Water Chemistry Control – BWR Program (Section B.1.42) and condition monitoring through in-vessel examinations of the reactor vessel internal attachment welds.

The program uses inspections, scheduling, acceptance criteria, and flaw evaluation in conformance with BWRVIP guidelines, including BWRVIP-48-A. The program includes welds between the vessel wall and vessel ID brackets that attach components to the vessel. The internal attachment weld can be a simple weld or a weld build-up pad on the vessel.

Flaw indications are evaluated in accordance with the criteria contained in BWRVIP-48-A. If flaws are detected, the program requires expanded inspection scope and re-inspection in accordance with the guidance provided in BWRVIP-48-A. Repair and replacement procedures comply with the requirements of ASME Code, Section XI.

NUREG-1801 Consistency

The BWR Vessel ID Attachment Welds Program is consistent with the program described in NUREG-1801, Section XI.M4, BWR Vessel ID Attachment Welds.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following discussion provides objective evidence that the BWR Vessel ID Attachment Welds Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation. Inspections of reactor vessel internal attachment welds are governed by BWRVIP-48-A.

- In 1997, jet pump riser brace welds (six of 10) were inspected with no indications.
- In 2001, jet pump riser pipe of the upper brace and lower brace attachment yoke welds (six welds) were inspected. No indications were noted.

- In 2008, feedwater brackets (eight brackets) and steam dryer brackets were inspected with no relevant indications.
- In 2009, examination of the core spray bracket alignment pins located on the annulus side of the shroud found that one of the two alignment pin tack welds associated with the lower bracket of the A pair at 276° azimuth was cracked. The indication identified on the alignment pin tack weld was determined to be acceptable to leave as found. No changes were noted during reinspections in 2011 or 2013.
- In 2011, jet pump assembly welds were examined. No indications were reported.

The inspections results and subsequent evaluations and corrective actions demonstrate that the BWR Vessel ID Attachment Welds Program has been effective. The continued application of proven methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The BWR Vessel ID Attachment Welds Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.10 BWR VESSEL INTERNALS

Program Description

The BWR Vessel Internals Program manages cracking, loss of preload, loss of material, and reduction in fracture toughness for BWR vessel internal components in a reactor coolant environment. The program performs inspections and flaw evaluation in conformance with the guidelines of applicable BWRVIP reports. The program also mitigates the aging effects by controlling water chemistry with the Water Chemistry Control – BWR Program (Section B.1.42).

This program includes (1) determining the susceptibility of cast austenitic stainless steel components to thermal embrittlement, (2) accounting for the synergistic effect of thermal aging and neutron irradiation, and (3) implementing a supplemental examination program, as necessary.

Thermal and/or neutron embrittlement in susceptible CASS and X-750 components are indirectly managed by performing periodic visual inspections capable of detecting cracks in the component. This program provides screening criteria of CASS components to determine the susceptibility to thermal aging on the basis of casting method, molybdenum content, and percent ferrite. The program also manages aging effects in stainless steel and nickel alloy components. Precipitation-hardened (PH) martensitic stainless steel (e.g., 15-5 and 17-4 PH steel) materials and martensitic stainless steel (e.g., 403, 410, 431 steel) are not used in the RBS reactor vessel internal components. The crack growth rate evaluations and fracture toughness values specified in BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100, Revision1, are used for cracked core shroud welds exposed to the neutron fluence values specified in these BWRVIP reports.

Applicable industry standards and staff-approved BWRVIP documents provide the basis for scheduling inspections to provide timely detection of aging effects, appropriate NDE inspection techniques, acceptance criteria, flaw evaluation, and repair/replacement, as needed.

NUREG-1801 Consistency

The BWR Vessel Internals Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M9, BWR Vessel Internals.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
2. Preventive Actions	Revise BWR Vessel Internals Program procedures to state that for core shroud repairs or other IGSCC repairs, the program will maintain operating tensile stresses below a threshold limit that precludes IGSCC of X-750 material.
4. Detection of Aging Effects	The susceptibility to neutron or thermal embrittlement for reactor vessel internal components composed of CASS and X-750 alloy will be evaluated.
4. Detection of Aging Effects	Revise BWR Vessel Internals Program procedures as follows: Portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions) will be inspected, using an inspection technique capable of detecting the critical flaw size with adequate margin. The critical flaw size will be determined based on the service loading condition and service-degraded material properties. The initial inspection will be performed either prior to or within five years after entering the period of extended operation. If cracking is detected after the initial inspection, the frequency of re-inspection will be justified based on fracture toughness properties appropriate for the condition of the component. The sample size for the initial inspection of susceptible components will be 100 percent of the accessible component population, excluding components that may be in compression during normal operations.

Operating Experience

The following discussion provides objective evidence that the BWR Vessel Internals Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2000, inspections of the steam dryer noted linear indications on the support ring of the dryer. The steam dryer's sole function is to remove moisture from steam in order to minimize erosion of piping and the turbine. The indications on the support ring have no effect on this function. The longest indication observed appears approximately 1 inch in length. Indications of this type were observed and evaluated on the steam dryer support ring in 1987, 1989, 1990, and 1997. Support ring cracks have also been observed at other BWRs. The cracking is attributed to IGSCC. The cracking is not structurally significant and is not related to flow-induced vibration. The functions of the dryer and upper support ring are not affected by the cracks.

- A new indication was identified in 2006 located in the steam dryer skirt. The length of the identified crack is less than the bounding length (4.5 inches) contained in the past evaluation. The entire steam dryer support ring was inspected and no other support skirt indications were observed. The indication in the skirt has no practical impact on the structural integrity or the function of the skirt, based on the reported flaw size and location. It was judged acceptable to leave the indication as-is and include it in the in-vessel visual inspection monitoring plan for future inspection.

- A new weld indication and a weld crack were observed in 2008 during examination of the steam dryer. These two welds were repaired during the outage. The repairs were inspected in 2009 with no changes noted.

- In 2009, the jet pump adapter to support plate weld was found with a linear indication at the base of the weld root to shroud support plate. The evaluation of the indication concluded that the indication is a surface anomaly. No relevant indications were recorded during the UT examination. No additional evaluation of the weld is needed.

- Steam dryer support ring indications were inspected in 2011 and 2013 with no changes noted.

- Core spray piping welds were examined during refueling outages occurring from 2000 to 2015 with no indications noted.

- A focused self-assessment of the BWR Vessel Internals Program was performed in 2013. The purpose of this assessment was to determine the overall health of the program. Based on the assessment, the team concluded that the program had weaknesses in the areas of program documentation, implementation of the Institute of Nuclear Power Operations (INPO) 2009 reactor vessel review visit recommendations, and operating experience reviews. Seven standards performance deficiencies, six negative observations, and two positive observations were identified. Condition reports were initiated for the standards performance deficiencies, and work tracking actions for the negative observations.

  One standard performance deficiency entailed a missed inspection of the top guide in accordance with the provisions of BWRVIP-183. The inspection should have occurred in either 2009 or 2011. As stated in BWRVIP-183, cracking along the fabrication welds does not impact the top guide function due to the top guide stud bolting. River Bend had performed the inspection of this bolting on the recommended frequency and found no indications. The missed inspection on the top guide was performed in 2015.

Another standard performance deficiency identified numerous discrepancies between the scheduling database and the outage report summaries. The discrepancies were corrected.

- The 2015 program health report rated the program as excellent in all performance areas. Shroud flaw evaluation issues were pending resolution with input from new BWRVIP guidelines awaiting NRC approval. Remaining dry tubes replacements were scheduled to be completed by 2019.

The inspection results and subsequent evaluations and corrective actions demonstrate that the BWR Vessel Internals Program has been effective. The continued application of proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The BWR Vessel Internals Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.11 COATING INTEGRITY

Program Description

The Coating Integrity Program is a new program that will entail periodic visual inspections of coatings applied to the internal surfaces of in-scope components in an environment of treated water, waste water, or lubricating oil where loss of coating or lining integrity could impact the component's or downstream component's current licensing basis intended function(s). For coated surfaces that do not meet the acceptance criteria, coating repair or replacement is accompanied by physical testing where possible. The training and qualification of individuals involved in coating inspections of noncementitious coatings are in accordance with ASTM standards endorsed in Regulatory Guide (RG) 1.54, including limitations, if any, identified in RG 1.54 for those standards. For cementitious coatings or linings, inspectors should have a minimum of five years of experience inspecting or testing concrete structures or cementitious coatings or linings or a degree in the civil/structural discipline and a minimum of one year of experience.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Coating Integrity Program will be consistent with program elements described in LR-ISG-2013-01,"Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-scope Piping, Piping Components, Heat Exchangers and Tanks," for XI.M42, "Internal Coatings/Linings for In-scope Piping, Piping Components, Heat Exchangers, and Tanks."

Exceptions to NUREG-1801

None

Enhancements to NUREG-1801

None

Operating Experience

The following discussion provides objective evidence that the Coating Integrity Program, when fully established, will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

The Coating Integrity Program is a new program at RBS. Industry operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

A review of operating experience at RBS identified examples of repairs to damaged coatings in nonsafety-related system components that do not perform license renewal intended functions.

- In 2013, tubesheet coating was found separated from the tubesheet in a main condenser waterbox. RBS has noted that this condition is not unusual after each operating cycle. The coating was installed during refueling outages in 2008, and site experience is still being gained. Repairs were performed during refueling outages in 2009 and 2011. Tasks were completed to repair the degraded coatings identified in 2013.

- In 2013, a crack was found in the valve body lining in the seating area of a valve in the liquid radwaste system. As the system could still process water with the valve body lining in this condition, the condition was addressed using normal work processes.

- In 2015, localized damage to tubesheet coatings was found in main condenser waterboxes. The condition was addressed using normal work processes.

- In 2015, during refurbishment of a clarifier in the cooling tower makeup water system, the clarifier coating was determined to have reached the end of its life. A contractor was selected to upgrade the coating, and the condition was addressed using normal work processes.

- In 2016, during repair of a valve in the liquid radwaste system, the rubber coating was found separated from the valve body. The condition was addressed using normal work processes.

As discussed in element 10 to NUREG-1801, Section XI.M42, as described in LR-ISG-2013-01, the inspection techniques and training of inspection personnel associated with this program will be consistent with industry practices that have been demonstrated effective at detecting loss of coating or lining integrity.

The Coating Integrity Program will be consistent with the program described in NUREG-1801, as revised by LR-ISG-2013-01, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Coating Integrity Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.12 COMPRESSED AIR MONITORING

Program Description

The Compressed Air Monitoring Program manages loss of material in compressed air systems by periodically monitoring the air for moisture and contaminants and by inspecting system internal surfaces. Air quality is maintained in accordance with limits based on consideration of manufacturer recommendations as well as guidelines in EPRI NP-7079 and TR 108147, ASME OM-S/G-1998 (Part 17), and ISA-S7.0.01-1996. Inspection frequencies and acceptance criteria are in accordance with SOER 88-01 and applicable industry standards. Documents such as EPRI NP-7079, ASME OM-S/G-1998 (Part 17), and ISA-S7.0.01-1996 provide guidance on preventive measures, inspection of components, and testing and monitoring air quality. Periodic and opportunistic internal visual inspections of components (accumulators, flex hoses, tubing, etc.) are performed to monitor for signs of corrosion. Air quality parameters are trended to determine if alert levels or limits are being approached or exceeded. Instrument air is tested for moisture and other corrosive contaminants.

NUREG-1801 Consistency

The Compressed Air Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M24, Compressed Air Monitoring, with one exception.

Exceptions to NUREG-1801

The Compressed Air Monitoring Program has the following exception.

Element Affected	Exception
5. Monitoring and Trending	NUREG-1801 recommends the recording and trending of daily readings of system dew point. Dew point testing and trending is performed quarterly.[1]

Basis for Exception

1. The frequency of dew point testing was reported in the RBS response to GL 88-14. A review of operating experience, condition reports, and recent system health reports did not find degradation that has threatened component intended functions, thus demonstrating adequacy of the quarterly dew point testing frequency.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
2. Preventive Actions	Revise Compressed Air Monitoring Program procedures to apply consideration of the guidance of ASME OM-S/G-1998 (Part 17); EPRI NP-7079; and EPRI TR-108147 to the limits specified for the air system contaminants.
4. Detection of Aging Effects	Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic visual inspections of accessible internal surfaces of system components (accumulators, flex hoses, tubing, etc.). Specify inspections at frequencies recommended in ASME OM-S/G-1998 (Part 17).

Operating Experience

The following operating experience provides objective evidence that the Compressed Air Monitoring Program will be effective in ensuring that intended functions will be maintained consistent with the current licensing basis through the period of extended operation.

- In 2012, during an effectiveness review of SOER 88-01 Recommendation 4, it was discovered that the instrument air dew point measurement taken in April 2011 at an instrument air drywell header drain did not meet acceptance criteria. The measured dew point reading was +13.30°F, which is above the dew point criteria of less than -25°F at line pressure. Previous dew point measurements of the instrument air system at the same location have resulted in readings of -30°F to -40°F, which indicates moisture in the line prior to or during the measurement, or the dew point meter was out of calibration. The dew point measurement was acceptable in accordance with ANSI Standard IAS-S7.0.01-1996, which states that the dew point should be at least 18°F below the minimum temperature at any point in the instrument air lines. A dew point reading in October 2012 at this location was -25.2°F, which met the procedural acceptance criteria of less than -25°F.

- In 2013, Entergy completed the effectiveness review of the RBS response to SOER 88-01 on instrument air system failures, Recommendation 4 (Rev. 3). Air quality monitoring is meeting the intent of Recommendation 4. Particulate, dew point, and oil/hydrocarbon sampling are being performed at various locations throughout the plant. Safety-related air accumulators, associated check valves, and safety-related air end users have been evaluated to ensure they can perform their intended safety function.

- In 2014, a dew point value of -8.14°F was measured in the instrument air system. Per the preventive maintenance template, the required dew point acceptance criterion is less than -25°F. The template did not have a step for the maintenance technician to contact the system engineer after completion of the sample. This sample was the first sample taken after an event where service air was cross-tied to instrument air. The lower quality service air has the potential to create an increased dew point, which was seen in this sample. There have been no failed tests after this occurrence. An action was initiated to incorporate steps in the preventive maintenance procedure to contact the system engineer with the results and to write a condition report if the sample's dew point does not meet the criteria of less than -25°F.

As discussed in element 10 to NUREG-1801, Section XI.M24, this program considers the technical information and industry operating experience provided in NRC IN 81-38; IN 87-28; IN 87-28, Supplement 1; License Event Report 50-237/94-005-3; IN 2008-06; NRC GL 88-14; INPO SOER 88-01; EPRI NP-7079; and EPRI TR-108147.

The sampling results and subsequent evaluations and corrective actions demonstrate that the Compressed Air Monitoring Program has been effective. The continued application of this proven approach provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Compressed Air Monitoring Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.13 CONTAINMENT INSERVICE INSPECTION – IWE

Program Description

The Containment Inservice Inspection – IWE (CII-IWE) Program is implemented through plant procedures which provide administrative controls for the conduct of activities that are necessary to fulfill the requirements of 10 CFR 50.55a, which imposes the inservice inspection (ISI) requirements of the ASME B&PV Code, Section XI, Subsection IWE, for steel containments (Class MC) and steel liners for concrete containments (Class CC). There are no tendons associated with the RBS steel containment vessel (SCV). The RBS containment system is a General Electric BWR Mark III pressure suppression containment system consisting of a drywell, vapor suppression pool, and a primary containment structure. The RBS primary containment structure is a low-leakage, free-standing SCV consisting of a vertical upright cylinder with a torispherical dome and a flat liner plate at the base. The SCV forms the containment pressure boundary and encloses the vapor suppression pool and the drywell.

The program includes the SCV and its integral attachments, containment equipment hatches, airlocks, and pressure-retaining bolting. The program performs visual examinations (general visual, VT-1 and VT-3) to assess the general condition of the containment and to detect evidence of degradation that may affect structural integrity or leak tightness. The visual inspections monitor the condition of the SCV surface areas, including welds and base metal and integral attachments; personnel and equipment access hatches; and pressure-retaining bolting. Bolting is not susceptible to cracking and does not require surface or volumetric examinations to detect cracking per IWE. The CII-IWE Program specifies acceptance criteria, corrective actions, supplemental inspections as required, and provisions for expansion of the inspection scope when identified degradation exceeds the acceptance criteria. The code of record for the examination of the RBS Class MC components and related requirements is ASME Code Section XI, Subsections IWE, 2001 Edition with the 2003 Addenda, as mandated and modified by 10 CFR 50.55a.

The technical evaluation of NRC IN 92-20 for applicability concluded that a valid Type B LLRT of the RBS containment penetration bellows could be performed in accordance with the requirements of 10 CFR Part 50 Appendix J. Therefore, the IN 92-20 recommendation for augmented inspection of the bellows does not apply to the RBS program.

The CII-IWE Program includes provisions to ensure that the selection of bolting material, the selection of installation torque or tension, and the use of lubricants and sealants are appropriate for the intended purpose. Implementing procedures use recommendations delineated in NUREG-1339 and industry recommendations delineated in the Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 to ensure proper specification of bolting material, lubricant, and installation torque.

NUREG-1801 Consistency

The Containment Inservice Inspection – IWE Program, with an enhancement, will be consistent with the program described in NUREG-1801, Section XI.S1, ASME Section XI, Subsection IWE.

Exceptions to NUREG-1801

None

Enhancements

The following enhancement will be implemented prior to the period of extended operation.

Element Affected	Enhancement
2. Preventive Actions	Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

Operating Experience

The following operating experience provides objective evidence that the CII-IWE Program will be effective in ensuring that intended functions will be maintained consistent with the current license basis through the period of extended operation.

- In 2008, a visual (VT-3) examination of bolting was conducted. The bolting inspected was bolting that had been removed for access. The inspection was performed on the bolting material prior to reinstallation. No deficiencies were noted.
- In 2008, during an IWE examination, divers noted a small pit on the suppression pool floor. The depth of the pit was 0.055 inches, and it was located in the bottom of a dent measuring 0.120 inches deep by 4½ inches in diameter. An evaluation concluded that the suppression pool liner remained fully functional (i.e., containment leak tightness and structural integrity were not challenged). This conclusion was reached through a review of design documents without the need for further engineering analysis. The condition was deemed acceptable as-is.
- In 2009, a visual examination was conducted of an inside wall section for approximately 20 feet. No deficiencies were noted.
- In 2013, a visual examination was conducted on outside wall sections from the annulus floor to the dome. No areas failed the examination criteria. Light rust noted on and adjacent to several attachment welds was evaluated as acceptable.

- In 2013, a visual examination was conducted of an inside wall section running from the floor to the dome. No deficiencies were noted.
- In 2015, visual (VT-3) examinations were conducted on bolted connections for electrical penetrations. The examination included bolts, studs, nuts, bushings, washers, and threads in base material and flange ligaments between thread stud holes. No deficiencies were noted.

NRC IN 2010-12 documented issues involving corrosion of the steel containment liner. The information notice was reviewed for applicability at RBS. The events documented in the information notice were primarily applicable to a concrete containment with a steel liner. The containment at RBS is a free-standing steel containment. Therefore, the containment structure is not vulnerable to the same degradation mechanisms. Adequate barriers are in place to identify anomalies on the containment through the CII-IWE Program. No additional action was deemed necessary.

NRC IN 2011-15 documented issues with steel containment degradation. RBS is not susceptible to the coating degradation or corrosion of steel containment as documented in IN 2011-15 because the suppression pool steel surfaces in contact with the suppression pool water are covered with stainless steel cladding and plates.

As discussed in element 10 to NUREG-1801, Section XI.S1, this program considers the technical information and industry operating experience provided in NRC IN 86-99, IN 88-82, IN 89-79, IN 2004-09, NUREG-1522, GL 87-05, IN 97-10, IN 92-20, IN 2006-01, NRC IE Bulletin 82-02, NRC GL 91-17, EPRI NP-5769, EPRI NP-5769, and EPRI TR-104213. Operating experience is evaluated in accordance with the operating experience program, and relevant information and lessons learned are incorporated into the CII-IWE Program documentation.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the CII-IWE Program has been effective. The continued use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The CII-IWE Program provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.14 CONTAINMENT LEAK RATE

Program Description

The Containment Leak Rate Program consists of tests performed in accordance with the regulations and guidance provided in 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," Option B; RG 1.163, "Performance-Based Containment Leak-Testing Program"; NEI 94-01, "Industry Guideline for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J"; and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements."

Three types of tests are performed under Option B. Types A, B and C leakage rate testing will be implemented in accordance with the criteria set forth in RG 1.163, NEI 94-01, Revision 3-A, and the testing criteria of ANSI/ANS-56.8-2002. Type A tests are performed to determine the overall primary containment integrated leakage rate at the loss of coolant accident peak containment pressure. Performance of the integrated leakage rate test (ILRT) demonstrates the leak-tightness and structural integrity of the containment. A general visual examination of the accessible interior and exterior areas of the steel containment vessel is performed prior to any ILRT. The Type A leakage rate test is performed during a period of reactor shutdown. Type B and Type C containment local leakage rate tests (LLRT) are intended to detect local leaks and to measure leakage across each pressure-containing or leakage-limiting boundary of containment penetrations. Test frequencies for Type A, B and C leakage rate testing comply with the requirements of 10 CFR Part 50, Appendix J, Option B based upon the criteria in NEI 94-01, Revision 3-A.

The parameters monitored are leakage rates of the steel containment vessel and associated welds, penetrations, fittings, and other access openings. The leakage rate acceptance criteria are established in accordance with 10 CFR Part 50, Appendix J, Option B.

The Containment Leak Rate Program provides measures to detect degradation prior to loss of intended function. The program provides for detection of pressure boundary degradation due to aging effects such as loss of leak tightness, loss of material, cracking, or loss of sealing in various systems penetrating containment. The program also provides for detection of age-related degradation in material properties of gaskets, O-rings, and packing materials for the containment pressure boundary access points. The use of pressure tests verifies the pressure-retaining integrity of the containment. The containment leakage rate tests demonstrate the leak-tightness of containment isolation barriers. While satisfactory performance of containment leakage rate tests demonstrates the leak-tightness and structural integrity of the 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. This is achieved with implementation of a containment inservice inspection program as described in ASME Section XI, Subsection IWE.

The Containment Leak Rate Program documents and trends test results in accordance with the provisions of 10 CFR Part 50, Appendix J, Option B, based upon the criteria in NEI 94-01, Revision 3-A. The Containment Leak Rate Program demonstrates that the test results meet the acceptance criteria.

Evaluations are performed for test or inspection results that do not satisfy established criteria and a condition report is initiated to document the issue in accordance with plant administrative procedures.

The 10 CFR Part 50, Appendix B corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions are performed in accordance with applicable procedures that meet the requirements of 10 CFR Part 50, Appendix J, Option B.

NUREG-1801 Consistency

The Containment Leak Rate Program is consistent with the program described in NUREG-1801, Section XI.S4, 10 CFR Part 50, Appendix J, with exceptions.

Exceptions to NUREG-1801

The Containment Leak Rate Program has the following exceptions.

Element Affected	Exception
5. Monitoring and Trending	The Containment Leak Rate Program follows Option B of 10 CFR Part 50, Appendix J. NUREG-1801 XI.S4 element 5 states that 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. NUREG-1801 XI.S4 indicates the use of Revision 2-A of NEI 94-01. RBS has adopted NEI 94-01 Revision 3-A subject to the conditions specified in the safety evaluation report for RBS License Amendment Request dated October 29, 2015 to establish testing intervals for its Containment Leak Rate Program.[1]
7. Corrective Actions	NUREG-1801 XI.S4 element 7 states, "Corrective actions are taken in accordance with 10 CFR Part 50, Appendix J, and NEI 94-01." NUREG-1801 XI.S4 indicates the use of Revision 2-A of NEI 94-01. RBS has received approval to apply the provisions for corrective actions of NEI 94-01 Revision 3-A subject to the conditions specified in the safety evaluation report for RBS License Amendment Request dated October 29, 2015.[2]

Bases for Exceptions

1. The NRC staff has found the use of NEI 94-01, Revision 3-A, subject to the conditions specified in the safety evaluation report for RBS License Amendment Request dated October 29, 2015, acceptable in applying Option B of 10 CFR Part 50, Appendix J, for establishing testing intervals. See Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 191 to Facility Operating License No. NPF-47 (ADAMS Accession No. ML16287A599).
2. The NRC staff has found that the provisions of NEI 94-01, Revision 3-A, subject to the conditions specified in the safety evaluation report for RBS License Amendment Request dated October 29, 2015, are acceptable for corrective actions. See Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 191 to Facility Operating License No. NPF-47 (ADAMS Accession No. ML16287A599).

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Containment Leak Rate Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2007, the outboard isolation valve of penetration KJB-Z26 exceeded its limit for the LLRT. This is an isolation valve for the fuel pool coolers common header outlet to the refueling cavity. The leak rate of this valve does not contribute to the total Type B and C testing leakage but contributes to the secondary containment bypass leakage. The increased leak rate was determined acceptable since the inboard containment penetration valve had a reduced leak rate such that total leakage through the penetration was within the acceptable limit.

- In 2013, the outboard MSIV leak rate exceeded the procedural limit, and the leakage test for a main steam line outboard drain isolation valve could not be completed because the valve could not be pressurized. The torque switch on the drain isolation valve was replaced, and retesting confirmed an acceptable leak rate for this valve. With the as-left leakage of the drain isolation valve within acceptable values, the leakage past the outboard MSIV was evaluated as acceptable since the combined leakage for the Division I steam line isolation valves was within the acceptable range.

In 2014, the NRC issued IN 2014-07, "Degradation of Leak-Chase Channel Systems for Floor Welds of Metal Containment Shell and Concrete Containment Metallic Liner." This information notice concerned degradation of leak-chase channel systems of steel containment shells or steel liners of concrete containment structures. Based on a review of design specifications and associated drawings, RBS containment design varies from the design discussed in IN 2014-07. The configuration utilizes fully welded stainless steel test channels with stainless steel couplings and threaded plugs which were seal welded after the weld joints were tested for leakage. A visual examination is performed on the accessible parts of the suppression pool floor liner plate leak-chase system seal plugs in accordance with ASME Code Section XI, Subsection IWE requirements to identify potential degradation that could affect leak-tightness.

NRC Regulatory Issue Summary (RIS) 2016-07 informed the industry of potential ASME Code non-compliance related to failure to accurately identify containment areas for inspection. There are two distinct but related areas of concern. The first pertains to the use and inspection of moisture barriers, which are not in use at RBS. The second pertains to correctly identifying surface areas requiring augmented examination and performing the associated inspections. RBS previously performed an evaluation that determined there are no surface areas requiring augmented examination. Therefore, RBS is not susceptible to the two areas of concern presented in the RIS.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the Containment Leak Rate Program has been effective. The continued use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Containment Leak Rate Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.15 DIESEL FUEL MONITORING

Program Description

The Diesel Fuel Monitoring Program manages loss of material in piping, tanks and other components in an environment of diesel fuel oil by verifying the quality of the fuel oil source. This is performed by receipt inspection, sampling, and limiting the quantities of contaminants before allowing it to enter the fuel oil storage tanks. Parameters monitored include water and sediment content, total particulates, and levels of microbiological organisms in the fuel oil. The program includes multi-level sampling of fuel oil storage tanks. Where multi-level sampling cannot be performed due to design, a representative sample is taken from the lowest part of the tank. A stabilizer/biocide is added to new fuel.

The Diesel Fuel Monitoring Program includes periodic inspections of low flow areas where contaminants may collect such as in the bottom of tanks. The fuel oil storage tanks are periodically sampled, drained, inspected, and cleaned. Internal tank inspections for signs of moisture, contaminants, and corrosion will be performed at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation. Where degradation is observed, a wall thickness determination is made. Water, biological activity, and particulate concentrations are monitored and trended in accordance with the plant's technical specifications or at least quarterly.

The One-Time Inspection Program (Section B.1.32) includes inspections to verify that the Diesel Fuel Monitoring Program has been effective at managing the effects of aging.

NUREG-1801 Consistency

The Diesel Fuel Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M30, Fuel Oil Chemistry.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise Diesel Fuel Monitoring Program procedures to monitor levels of microbiological organisms in the standby diesel generator (SDG) and HPCS diesel generator fuel oil storage and day tanks, and diesel-driven fire pump fuel oil storage tanks.
4. Detection of Aging Effects	Revise Diesel Fuel Monitoring Program procedures to include periodic multi-level sampling of tanks within the scope of the program. Include provisions to obtain a representative sample from the lowest point in the tank, if tank design does not allow for multi-level sampling.
4. Detection of Aging Effects	Revise Diesel Fuel Monitoring Program procedures to include a periodic cleaning and internal visual inspection of the tanks within the program. In the areas of any degradation identified during the internal inspection, a volumetric inspection shall be performed. In the event an internal inspection cannot be performed due to design limitations, a volumetric examination shall be performed. Perform cleanings and internal inspections at least once during the 10-year period prior to the period of extended operation and at succeeding 10-year intervals.
5. Monitoring and Trending	Revise Diesel Fuel Monitoring Program procedures to (a) monitor biological activity and particulate concentrations in the diesel-driven fire pump fuel oil storage tanks at least quarterly, and (b) monitor levels of microbiological organisms in the SDG and HPCS fuel oil storage and day tanks at least quarterly.

Operating Experience

The following operating experience provides objective evidence that the Diesel Fuel Monitoring Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis during the period of extended operation.

- In 2008, the 10-year cleaning and inspection of the diesel fuel oil storage tanks was performed for the Division I, II and III tanks. Aside from a small amount of sludge in Tank 1C, no issues with the tanks were noted.

- In August 2013, an upward trend in particulate concentration was identified for the Division I EDG fuel oil storage tank. Measured concentrations were well below the Technical Specification limit for particulate contamination in the diesel fuel oil storage tanks. Until the completion of further analysis, an interim measure required particulate analysis of new fuel prior to adding fuel to the storage tanks. A diesel fuel oil sample taken from multiple levels in the Division I tank indicated the major particulate constituent in the fuel was salt. The particles seen in this analysis report were much smaller than the micron size of the diesel generator fuel filters; therefore, these particulates were not suspected of causing issues with filter plugging. Based on industry experience, salt in fuel rarely causes issues with filter plugging. A review of samples from the previous 15 months for the Division II and III fuel oil storage tanks showed the Division I tank had the highest total particulate level.

  In December 2013, a similar upward trend in particulate concentration was identified in the Division II fuel oil storage tank, and in February 2014 particulate concentration in the tank exceeded the site administrative limit. The fuel oil was filtered using the installed transfer system, and both fuel oil filters were replaced. The resulting particulate concentration was acceptable. An upward trend in particulate concentration was identified again in April 2014, and the tank was again filtered to reduce the concentration.

  Final completed actions documented in the review of this condition in July 2014 included filtration of the three DG fuel oil storage tanks and the purchase of a filter skid to filter new fuel before adding it to the storage tanks. Also, a preventive maintenance task was developed to continue periodic filtering of the fuel tanks to mitigate particulate concentration based on vendor recommendations.

The results of tank inspections and recent diesel fuel sampling and corrective actions taken demonstrate that the Diesel Fuel Monitoring Program has been effective. The continued application of proven sampling and inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

<u>Conclusion</u>

The Diesel Fuel Monitoring Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.16 ENVIRONMENTAL QUALIFICATION (EQ) OF ELECTRIC COMPONENTS

Program Description

The Environmental Qualification (EQ) of Electric Components Program manages the effects of thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. The NRC has established nuclear station environmental qualification (EQ) requirements in 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49, which 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 LOCA, HELB, or high radiation) are qualified to perform their safety function in those harsh environments. As part of environmental qualification, 10 CFR 50.49 requires that the effects of significant aging mechanisms be addressed.

As required by 10 CFR 50.49, EQ components are refurbished, replaced, or their qualification is extended prior to reaching the aging limits established in the evaluation. Reanalysis of an aging evaluation addresses attributes of analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions. Some aging evaluations for EQ components are time-limited aging analyses (TLAAs) for license renewal.

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 that require 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 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 to be 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 to be 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 that 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 to be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is, sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

NUREG-1801 Consistency

The Environmental Qualification (EQ) of Electric Components Program is consistent with the program described in NUREG-1801, Section X.E1, Environmental Qualification (EQ) of Electric Components.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Environmental Qualification (EQ) of Electric Components Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- A quality assurance audit in 2006 included the EQ Program. The purpose of the audit was to evaluate programmatic adequacy and effectiveness of implementation of the engineering programs at RBS. There were no findings associated with the EQ Program. Work packages that were reviewed to ensure EQ requirements are established correctly found that the packages did correctly implement EQ requirements. A review of condition reports noted one that identified issues with adequately implementing the program, particularly with establishing appropriate due dates for EQ preventive maintenance tasks. As a result of the condition report, actions have been completed to develop new EQ preventive maintenance frequencies and update these due dates in the work tracking process.

- In 2011, an equipment qualification impact summary (EQIS) was identified as containing an unnecessarily conservative conclusion about operability of an RHR pump with its related room door open. The EQIS stated that the pump was not qualified for the higher temperature and radiation postulated for the zone with the door open. A review of environmental design criteria verified that the qualification of the pump was acceptable for the expected harsh environment temperature and radiation levels of the room. The expected values envelope the most severe design basis accident environment for these zones. Based on the evaluation, the breaching of the RHR room door would not affect operability of the environmentally qualified equipment in the zones separated by the door. A revised EQIS was issued to supplement the statement provided by the original EQIS regarding the qualification of the pump.

- In 2013, a discrepancy was identified with the environmental qualification for the standby liquid control explosive valves, which are supplied by a subcontractor through the GE qualification program. In 2010, a valve had been refurbished directly by the subcontractor without certification to the GE qualification program. GE reviewed the document package for the refurbished valve and found it consistent with GE design requirements.

- In 2013, components on two reactor feedwater isolation valve operators were identified with an EQ life that would expire before the 2015 outage. The frequency of the component replacement activity had been changed as part of the transition from an

18-month fuel cycle to a 24-month cycle without proper review by the EQ program owner. No EQ limit life was exceeded.

- In 2013, the replacement of an obsolete standby gas treatment system temperature controller could not be completed as scheduled because the purchase order delivery date and corresponding 2013 commitment date did not allow sufficient time for required thermal aging testing. The duration of the test for thermal aging was determined by the vendor after receiving environmental criteria specific to RBS. Actions were taken to accept a reduced qualified life in order to complete the qualification testing and receive the new controllers at RBS in 2013. The issue was discussed with the affected personnel, and a condition report was initiated to trend.

As discussed in element 10 of NUREG-1801,Section X.E1, EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life, in support of 10 CFR 50.49.

Program audits as well as identification and resolution of EQ issues demonstrate that the Environmental Qualification (EQ) of Electric Components Program has been effective. The continued use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Environmental Qualification (EQ) of Electric Components Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.17 EXTERNAL SURFACES MONITORING

Program Description

The External Surfaces Monitoring Program manages aging effects of components fabricated from metallic, elastomeric, and polymeric materials through periodic visual inspection of external surfaces for evidence of loss of material, cracking, reduction of heat transfer, reduced thermal insulation resistance, and change in material properties. When appropriate for the component and material, physical manipulation, such as pressing, flexing, and bending, is used to augment visual inspections to confirm the absence of elastomer hardening and loss of strength. The External Surfaces Monitoring Program is also credited for situations where the material and environment combinations are the same for the internal and external surfaces such that the external surfaces are representative of the internal surfaces.

Inspections are performed at least once every refueling cycle by personnel qualified through a plant-specific training program. Deficiencies are documented and evaluated under the corrective action program. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the component's intended functions are maintained.

Periodic visual inspections of a representative sample of in-scope mechanical indoor components under insulation (with process fluid temperature below the dew point) and outdoor components under insulation will be performed.

For polymeric (or non-metallic) materials, the visual inspection will include 100 percent of the accessible components. The flexible polymeric or elastomeric components that receive physical manipulation constitute at least 10 percent of the available surface area.

For stainless steel, the acceptance criterion is a clean, shiny surface. Other metals should not have abnormal surface indications. For flexible polymeric materials, a uniform surface texture (no cracks) and no change in material properties (e.g., hardness, flexibility, physical dimensions, color unchanged from when the material was new) are the acceptance criteria. For rigid polymeric materials, acceptable conditions are no surface abnormalities, such as erosion, cracking, crazing, checking, and chalking.

Acceptance criteria for metallic components are the absence of the following:

- Corrosion (loss of material).
- Leakage from or onto external surfaces (loss of material).
- Worn, flaking, oxide coated surfaces (loss of material).
- Corrosion stains on thermal insulation (loss of material).
- Protective coating degradation (cracking, flaking, and blistering).
- Leakage for detection of cracks on the external surfaces of stainless steel components in an environment containing halides.

Acceptance criteria for polymeric (or non-metallic) materials are the absence of the following:

- 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 for manipulation.
- Shrinkage, or loss of strength.

Thermal insulation is credited to reduce heat transfer from certain components to ensure that functions described in 10 CFR 54.4(a) are successfully accomplished. Insulation is installed in accordance with manufacturer specifications, including configuration features such as overlap and location of seams. Inspections of insulated components where the insulation is required to reduce heat transfer will be performed to ensure insulation degradation due to moisture intrusion has not occurred.

NUREG-1801 Consistency

The External Surfaces Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring of Mechanical Components, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation."

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise External Surfaces Monitoring Program procedures to include instructions to perform a visual inspection of accessible flexible polymeric component surfaces. The visual inspection should identify indicators of loss of material due to wear to include dimensional change, surface cracking, crazing, scuffing, and for flexible polymeric materials with internal reinforcement, the exposure of reinforcing fibers, mesh, or underlying metal. In addition, 10 percent of the available flexible polymeric surface area should receive physical manipulation to augment the visual inspection to confirm the absence of hardening and loss of strength (e.g., HVAC flexible connectors).
4. Detection of Aging Effects	Revise External Surfaces Monitoring Program procedures to specify the following for in-scope insulated components in a condensation or air – outdoor environment. • Periodic representative inspections will be conducted during each 10-year period during the period of extended operation. • For a representative sample of in-scope insulated indoor components with an environment of condensation (because the component is operated below the dew point) and insulated outdoor components, insulation will be removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections performed that can be a combination of 1-foot axial length sections and individual components for each material type. (continued)

Element Affected	Enhancement
4. Detection of Aging Effects (continued)	• Inspection locations will be locations with a higher likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection. ▸ No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction. ▸ No evidence of cracking. If the external visual inspections of the insulation reveal damage to its exterior surface or if there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on components subject to aging management review. The entire population of piping component surfaces subject to aging management review that have tightly adhering insulation will be visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections will not be credited towards the inspection quantities for other types of insulation.

Element Affected	Enhancement
6. Acceptance Criteria	Revise External Surfaces Monitoring Program procedures to include the following acceptance criteria: • Stainless steel should have a clean, shiny surface with no discoloration. There should be no leakage of stainless steel components in an environment of air containing halides. • Other metals should not have abnormal surface indications. • Flexible polymeric materials should have a uniform surface texture with the material in an as-new condition with no cracks, crazing, scuffing, discoloration, dimensional change, exposure of internal reinforcement for reinforced elastomers, hardening as evidenced by a loss of suppleness during manipulation where the component and material are appropriate for manipulation, and no shrinkage or loss of strength. • Rigid polymeric materials should have no erosion, cracking, checking, or chalking.

Operating Experience

The following operating experience provides objective evidence that the External Surfaces Monitoring Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2004, external corrosion was noted on a service water system valve. A new bonnet assembly was installed on the valve.
- In 2007, the protective coating on a service water system fill line isolation valve was noted as degraded. The valve was repainted.
- In 2015, an external inspection of a fire water storage tank was completed with no discrepancies identified.
- In 2015, an external inspection of the second fire water storage tank was completed. No deficiencies were noted with the tank.
- In 2015, rust was found on the bottom of the C RHR motor where it mounts to the coupling spacer between the pump and motor. The rust appeared to be surface rust on the outside of the lower end shield of the motor's base, which sits on the barrel housing of the pump. The lower end shield contains and supports the lower guide bearing and oil reservoir. Surface rust would not affect form, fit or function of the pump or motor and is acceptable as is. The lubrication log data was checked for the lower bearing oil on each

of the RHR pump motors. Trending shows no wear metals and no abnormal trends regarding this oil. Vibration readings on the RHR pump motors have been stable.

- A 2015 walkdown of the turbine lube oil system found excess grease around the bearing of the emergency bearing oil pump, which is only operated during weekly tests, offline tests, or upon a low lube oil pressure signal. The pump has an automatic grease dispenser. A work request was initiated to replace the grease dispenser and clean the motor.

As discussed in element 10 to NUREG-1801, Section XI.M36, this program considers the industry operating experience from many utilities since the mid 1990's in support of the maintenance rule (10 CFR 50.65).

Visual inspections and the resulting corrective actions demonstrate that this program has been effective in maintaining the material condition of plant systems. The continued application of proven monitoring methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The External Surfaces Monitoring Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.18 FATIGUE MONITORING

Program Description

The Fatigue Monitoring Program ensures that fatigue usage remains within allowable limits for components identified to have a fatigue TLAA by (a) tracking the number of critical thermal and pressure transients for selected components, (b) verifying that the severity of monitored transients is bounded by the design transient definitions for which they are classified, (c) assessing the impact of the reactor coolant environment on a set of sample critical components including those from NUREG/CR-6260 and those components identified to be more limiting than the components specified in NUREG/CR-6260, and (d) addressing applicable fatigue exemptions. Tracking the number of critical thermal and pressure transients for the selected components ensures a cumulative usage factor (CUF) within allowable limits, including environmental effects where applicable. The environmental effects on fatigue for the identified critical components will be evaluated.

The program monitors the number of occurrences for the plant transients that cause significant fatigue usage. The program also provides for updates of 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 has been modified. RBS methods that are used to manage cumulative fatigue damage include cycle-based fatigue monitoring and stress-based fatigue monitoring.

NUREG-1801 Consistency

The Fatigue Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section X.M1, Fatigue Monitoring.

Exceptions to NUREG-1801

None

Enhancements

The second enhancement below on environmentally assisted fatigue usage calculations will be implemented at least two years prior to entering the period of extended operation. All other enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise Fatigue Monitoring Program procedures to monitor and track critical thermal and pressure transients for components with a fatigue TLAA.

Element Affected	Enhancement
2. Preventive Actions	Develop a set of fatigue usage calculations that consider the effects of the reactor water environment for a set of sample reactor coolant system components. This sample shall include the locations identified in NUREG/CR-6260, additional plant-specific component locations in the reactor coolant pressure boundary if they are found more limiting than those considered in NUREG/CR-6260. Environmental correction factors (F_{en}) shall be determined using the formulae recommended in NUREG-1801, X.M1. Stress analysis methods used as inputs to fatigue analyses will consider all six stress components. An environmentally assisted fatigue analysis using NUREG/CR-6909 will not use average temperature for complex transients. For simple transients that use average temperature, when the minimum temperature is below the threshold temperature, the maximum and threshold temperature will be used to calculate the average temperature.
4. Detection of Aging Effects	Revise Fatigue Monitoring Program procedures to provide 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, an unanticipated new thermal event is discovered, or the geometry of a component has been modified.

Operating Experience

The following operating experience provides objective evidence that the Fatigue Monitoring Program will be effective in ensuring that applicable component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- Plant operation data was not properly collected for fatigue monitoring software over two days in November 2006 due to a computer malfunction. The values for the specified parameters were available, but not in the preferred format. The defective hardware was replaced. A review of the missing information verified that no transient event took place during the period when plant operation data was not captured in the specified format. Therefore, the impact of the missed data is insignificant on the CUFs for components within the scope of the RBS Fatigue Monitoring Program.

- Plant operation data was not properly collected for fatigue monitoring software over three periods in March and April of 2007 due to computer malfunctions. The values for the specified parameters were available, but not in the preferred format. The computer malfunctions were corrected, and data was successfully recorded after April 9, 2007.

A similar incident happened over two days in May. The data collection program was restarted, and data collection in the preferred format resumed.

These events were evaluated for impact on the CUF calculations. The required data for the periods discussed above were retrieved from the plant data information system and provided for incorporation into relevant fatigue calculations.

- During the collection of plant data to perform an evaluation after the 2013 refueling outage, it was noticed that the plant operation data collection program unexpectedly stops recording data at the end of every year (November–December time frame) and starts recording data the following year (January–March time frame). Also, this software deficiency was noticed during unexpected plant transients or automatic reactor trips (e.g., a reactor trip initiated by a turbine trip on December 21, 2011). Because of this software deficiency, plant data was not automatically recorded as intended. As a result, plant data had to be obtained manually. An investigation was conducted concerning the data collection equipment and process. The investigation identified that the data collection software did not properly resume after the server for the plant operation data has been restarted. Work instructions have been updated to ensure that the data collection software for fatigue monitoring is operating properly upon reboot of the plant operation data system.

Monitoring cycle counts and initiating corrective action as necessary maintain the validity of associated fatigue analyses. Completion of the identified enhancements discussed above will provide additional assurance that the Fatigue Monitoring Program will be effective in the future. The application of this proven monitoring approach provides reasonable assurance that the associated analyses will remain valid or that appropriate corrective actions will be taken such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Fatigue Monitoring Program provides reasonable assurance that the effects of aging due to fatigue will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.19 FIRE PROTECTION

Program Description

The Fire Protection Program manages the following through periodic visual inspection of components and structures with a fire barrier intended function.

- Carbon steel components (loss of material).
- Concrete components (cracking and loss of material).
- Masonry walls (cracking and loss of material).
- Fire resistant materials (loss of material, change in material properties, cracking/ delamination, and separation).
- Elastomer components (increased hardness, shrinkage, and loss of strength).

The Fire Protection Program manages aging effects for components that serve a fire barrier function. Fire barriers include assemblies such as penetration fire seals, walls, floors, ceilings, fire-rated doors, cable tray enclosures, cable or conduit wraps, fire stops, junction boxes, and other fire-resistant materials that serve a fire barrier intended function. Fire barrier inspections are performed at a frequency in accordance with the NRC-approved fire protection program and Technical Requirements Manual.

The program includes periodic visual inspections of not less than 10 percent of each type of penetration fire seal. These inspections examine seals for signs of degradation or change in appearance, such as cracks, cuts, flaking, gaps or shrinkage, holes, gouges, punctures, tears, and openings in penetrations. If signs of degradation are detected within the sample, the scope of the inspection is expanded to include additional seals.

Walls, floors, and ceilings are periodically inspected for damage or defects such as cracks, gouges, holes or openings. Fire door periodic visual and functional inspections are performed to ensure that each fire door and associated hardware is free of holes, damage, or exposed defects, with proper clearance, latch engagement, and hinge movement.

The periodic visual inspection and functional test of the Halon fire suppression system associated with the power generation control complex is performed to examine for signs of corrosion and degradation that may lead to the loss of material of the Halon fire suppression system. The frequency of the periodic functional test is in accordance with the NRC-approved fire protection program and the Technical Requirements Manual.

NUREG-1801 Consistency

The Fire Protection Program is consistent with the program described in NUREG-1801, Section XI.M26, Fire Protection.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Fire Protection Program will be effective in ensuring that applicable component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- During the first quarter of 2012, a quality assurance audit of the Fire Protection Program was conducted. Through a review of program scope elements, personnel interviews, and audit observations, the audit team concluded the program is effective. The audit team concluded no issues were identified that challenge continued performance and the ability to maintain compliance with regulatory requirements. All 11 of the audit scope elements evaluated were deemed satisfactory.
- During the first quarter of 2014, a quality assurance audit of the Fire Protection Program was conducted. Through a review of program scope elements, personnel interviews, and audit observations, the audit team concluded the program is marginally effective in implementing activities that affect quality. The audit team concluded issues were identified that challenge continued performance and the ability to maintain compliance with regulatory requirements. Eleven of thirteen scope elements were rated satisfactory. The remaining two elements had findings:
  - The "Passive Fire Protection" scope element was rated unsatisfactory based on the fire protection surveillances performance and oversight due to the identification of poor work practices with completing and reviewing some test surveillances required by the Technical Requirements Manual.
  - The "Compensatory Measures" scope element was rated unsatisfactory based on untimely repair and return to service of fire protection equipment.

  Performance of surveillances and related work practices were reviewed.

  - A review of apparently missed surveillances on penetration seals determined that a nonconformance did not exist. A set of seals could not be inspected due to their location in an area inaccessible during power operations, but mechanical maintenance personnel substituted penetration seals of like type for each of the seals and included the substituted inspection data within the work order. This is an acceptable methodology for inaccessible seals.

- Issues with properly documenting surveillances were attributed to deficiencies with the training of mechanical maintenance personnel on proper performance of fire protection system surveillance testing. A few years previously, this responsibility had been transferred from Quality Control to Mechanical Maintenance, but no formal change management plan or training needs analysis could be found documenting a formal review for the transfer of this work responsibility. Training was prepared and provided to the maintenance department (mechanical, electrical, "Fix It Now" groups, and I&C), with a recurring frequency of once every three years.

A review of the timeliness of repairing and returning fire protection equipment to service determined that guidance was vague and the prioritization of fire protection corrective maintenance was inconsistent. Corrective actions included the following:

- Review of the list of fire protection work orders associated with a Technical Requirement Manual Limiting Condition for Operation that required a fire watch to ensure appropriate prioritization.
- Creation of a fire marshal position in Operations to monitor the condition of fire protection equipment and execution of fire protection program elements.
- Revisions to work management standards for prioritization of work orders for fire protection deficiencies.
- Incorporation of lessons learned into appropriate training.

These actions have been completed.

- The program health report for the fourth quarter of 2015 identified challenges with fire protection staffing. A backup fire protection engineer was hired in preparation for the retirement of the incumbent fire protection engineer.
- In January 2016 during a fire protection audit, the open fire door providing access to the D tunnel was found with a ring turn assembly that did not engage the associated door lock mechanism. The door is a normally open fire barrier. In the event of a fire or other condition requiring the door to be closed, the door will close and latch. The ring turn assembly functions to release one of the two latches on the door. With the ring turn assembly not functioning, the door will not be able to be reopened if closed. However, in this configuration, the door can be closed and can perform its design function. A work request was initiated to repair the door.
- In January 2016, an operator noted during rounds that the door to the auxiliary control room does not always latch properly. The locking mechanism does not engage properly every time the door is opened. A work order was generated to correct the condition.

- In February 2016, a fire door in the west side of the auxiliary building was discovered missing a bolt on the door closure device. The device is not securely fixed to the door as the screws in the device are also loose. This door is a fire door and still securely closed with this defect. The fire door was repaired.

As discussed in element 10 to NUREG-1801, Section XI.M26, this program considers the technical information and industry operating experience provided in NRC IN 88-56, IN 94-28, IN 97-70, IN 91-47 and NRC GL 92-08.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the Fire Protection Program has been effective. The continued application of proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Fire Protection Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.20 FIRE WATER SYSTEM

Program Description

The Fire Water System Program manages loss of material, loss of coating integrity, and flow blockage due to fouling for in-scope, long-lived, passive, water-based fire suppression system components using periodic flow testing and visual inspections in accordance with NFPA 25 (2011 Edition). In addition, the fire water system pressure is monitored such that a loss of system pressure is immediately detected and corrective action initiated. When visual inspections are used to detect loss of material and fouling, the inspection technique is capable of detecting surface irregularities that could indicate wall loss due to corrosion, corrosion product deposition, and flow blockage due to fouling. The program also manages coating integrity for the fire water tanks.

Testing or replacement of sprinkler heads that have been in service for 50 years is performed in accordance with the 2011 Edition of NFPA 25. Portions of the water-based fire water system that (a) are normally dry, but periodically subject to flow (e.g., downstream of the deluge valve in a deluge system) and (b) allow water to collect are subject to augmented examination beyond that specified in NFPA 25. The augmented examinations for the portions of normally dry piping that are periodically wetted include (a) periodic full flow tests at the design pressure and flow rate, or internal inspections, and (b) volumetric wall thickness evaluations.

The training and qualification of individuals involved in fire water storage tank coating inspections are in accordance with ASTM International standards endorsed in RG 1.54, including limitations, if any, identified in RG 1.54 on a particular standard.

Program acceptance criteria include (a) the water-based fire protection system can maintain required pressure, and (b) no unacceptable signs of degradation or fouling are observed during non-intrusive or visual inspections.

In the event surface irregularities are identified, testing is performed to ensure minimum design pipe wall thickness is maintained. In the event the fire water tank fails to meet acceptance criteria for coating or tank surface condition (e.g., peeling, delamination, blistering, flaking, cracking, or rust), the program specifies evaluation to ensure the tank can perform its intended function until the next inspection and that downstream flow blockage is not a concern.

NUREG-1801 Consistency

The Fire Water System Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation," with exceptions.

Exceptions to NUREG-1801

The Fire Water System Program has the following exceptions.

Element Affected	Exception
4. Detection of Aging Effects	NFPA 25, Section 5.2.1 specifies annual sprinkler inspections. RBS performs the sprinkler inspections once every 18 months, unless the inspection is in a high radiation area, in which case the inspection is performed every refueling cycle.[1]
4. Detection of Aging Effects	NFPA 25, Section 6.3.1 specifies flow testing every five years at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify the water supply still provides the design pressure at the required flow. RBS performs fire water pump flow testing to verify the water supply provides the design pressure and required flow.[2]
4. Detection of Aging Effects	NFPA 25, Section 13.2.5 specifies annual main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves. RBS will perform the main drain tests on 20 percent of the standpipes and risers every refueling cycle.[3]
4. Detection of Aging Effects	NFPA 25 Sections 9.2.6.4 and 9.2.7.1 specify an evaluation of interior tank coatings in accordance with the adhesion test of ASTM D 3359, Standard Test Methods for Measuring Adhesion by Tape Test, generally referred to as the "cross-hatch test." RBS inspects the tank interior coating for damage, chips, blisters, peeling, pinholes, rust or local or general failure of the coating every five years. In addition, RBS performs ultrasonic thickness checks or mechanical measurements of identified corroded areas. RBS will not always apply the cross-hatch test.[4]
4. Detection of Aging Effects	NFPA 25 Section 13.4.3.2.3 specifies trip testing preaction valves every three years with the control valve fully open. RBS trip tests the preaction valves with the control valves closed.[5]

Element Affected	Exception
7. Corrective Action	NFPA 25 Section 14.3.1 (14) specifies performing an obstruction evaluation when there is a 50 percent increase in time it takes for water to flow out the inspector test valve after the associated dry valve is tripped when compared to the original acceptance criteria or latest test. RBS trip tests the dry valve with the control valve closed.[6]

Bases for Exceptions:

1. As indicated by the note in Table 4a of LR-ISG-2012-02, access for some inspections is feasible only during refueling outages, which are scheduled every 24 months. Inspections performed at least once every refueling cycle interval have been effective at maintaining component intended function.
2. To flow test the hydraulically most remote hose connection of the automatic standpipe system in a manner that would provide sufficient information to verify design pressure and flow would generate a large quantity of liquid that is potentially radwaste and could create a risk of wetting components critical to normal and shut down operations. By not performing additional flow testing, the potential for creating radwaste and increasing operational risk is reduced.

   RBS flows the fire hoses listed in the Technical Requirements Manual (TRM) every three years per the TRM and will perform main drain tests on 20 percent of the standpipes and risers each refueling outage. Acceptance criteria consist of ensuring an open flow path by verifying valve operability and flow through valve and connections with no indication of obstruction or undue restriction of water flow.
3. As indicated by the note in Appendix D, Table 4a of LR-ISG-2012-02, access for some inspections is feasible only during refueling outages, which are scheduled every 24 months. Main drain tests on 20 percent of the standpipes and risers every 24 months provide adequate information to determine the condition of fire water piping is maintained consistent with design basis.
4. Cross hatch testing is a destructive test. RBS performs a visual inspection of the fire water tanks' interior coating every five years. RG 1.54 describes the use of ASTM test standard D4541-09, "Pull-Off Strength of Coatings Using Portable Adhesion Testers," as an acceptable alternative method for performing adhesion testing of coatings on metal substrates using a fixed-alignment adhesion tester. In addition, lightly tapping, scraping or cleaning the degraded area per Society of Protective Coatings (SSPC) SSPC-SP2, Hand Tool Cleaning; SSPC-SP3, Power Tool Cleaning; SSPC-SP11, Cleaning of Bare Metal; and SSPC-SP WJ-1, 2, 3 and 4, Water Jet Cleaning, will be used by a qualified specialist and design engineering to determine the extent of peeling, delamination and blistering to ensure that downstream flow blockage and tank integrity are not an issue.

5. Trip testing the preaction valves with the control valve fully open would allow fire water to enter the normally dry portion of the system. In addition, there is a potential for wetting down equipment critical to normal and shut down operations. The trip testing of the preaction valves relies on the residual pressure after the control valve is closed to pop open the preaction valve after a simulated open signal is generated. In the event the preaction valve does not open per design, the condition is entered into the corrective action program. In addition, the piping downstream of the in-scope preaction valves will be inspected for evidence of loss of material and the presence of foreign organic and inorganic material that could result in flow obstructions or blockage of a sprinkler head every five years by removing a sprinkler head from the most remote branch line from the source of water or using the inspector's test valve. In the event foreign material is found in a preaction system in a building during the five-year internal inspection of piping, each preaction system in that building shall have an internal inspection.
6. To prevent water from getting into the piping designed to be dry, the control valve prior to the preaction or deluge valve is closed or cracked open, and a drain valve downstream of the preaction or deluge valve is opened before the trip test occurs. Inspections of dry piping downstream of preaction and deluge valves ensure there is no blockage.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform an internal inspection of the auxiliary building and diesel generator building preaction system's dry piping for loss of material every five years. Perform an inspection by removing a sprinkler from the branch line most remote from the source of water or using an inspector's test valve. In the event foreign material is found in a preaction system that could result in flow obstructions or blockage of a sprinkler head in a building, each in-scope preaction system in that building shall have an internal inspection.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform an internal inspection every five years of the dry piping downstream of the deluge valves for the control building cable vaults (WS-6A, WS-6B and WS-6C), cable tunnel spray system (WS-8D), tunnels (WS-8E, WS-8F, WS-8G, WS-8H, WS-8K, WS-8L, WS-8M and WS-8N), and auxiliary building water curtains (WS-19 and WS-20) at 70-foot elevation and 141-foot elevation. The inspection shall be performed by opening a flushing connection, removing the most remote sprinkler head, and using a method capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion product deposition and flow blockage due to fouling. In the event foreign material is found in an in-scope deluge system in a building during the five-year internal inspection of piping, the dry piping of each in-scope deluge system in that building shall have an internal inspection.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform an internal piping inspection of every other wet fire water system every five years by opening a flushing connection at the end of one main and by removing a closed sprinkler head toward the end of one branch line for the purpose of inspecting the interior for evidence of loss of material and the presence of foreign material that could result in flow obstructions or blockage of sprinkler head or nozzles. The inspection method used shall be capable of detecting surface irregularities that could indicate wall loss below nominal pipe wall thickness due to corrosion, corrosion product deposition, and flow blockage due to fouling. Ensure procedures require a follow-up volumetric wall thickness evaluation where irregularities are detected. In the event foreign material is found, all wet pipe systems in that building shall have an internal inspection before returning to service.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform flow testing of underground piping in accordance with NFPA 291.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to inspect fire water sprinkler heads in accordance with NFPA 25, Section 5.2.1.1, with the exception of sprinkler orientation, foreign material, physical damage, and loading due to dust or debris.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Fire Water System Program procedures to inspect the interior of the fire water tanks in accordance with NFPA 25 (2011 Edition), Sections 9.2.6 and 9.2.7, including sub-steps, using the guidance of SSPC-SP2, Hand Tool Cleaning; SSPC-SP3, Power Tool Cleaning; SSPC-SP11, Cleaning of Bare Metal; and SSPC-SP WJ-1, 2, 3 and 4, Water Jet Cleaning.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to remove mainline strainers, inspect for damage and corroded parts, and clean every five years, and add a requirement to flush mainline strainers (basket or screen) until clear at least once per refueling cycle if a fire water system actuation occurred or flow testing occurred during that refueling cycle.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to specify that sprinkler heads are tested or replaced in accordance with NFPA 25 (2011 Edition), Section 5.3.1.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to specify a flow test or flush sufficient to detect potential flow blockage, or conduct a visual inspection of 100 percent of the internal surface of piping segments that allow water to collect in each five-year interval, beginning five years prior to the period of extended operation.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to specify volumetric wall thickness inspections of 20 percent of the length of piping segments that allow water to collect in each five-year interval of the period of extended operation. Measurement points shall be obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, microbiologically induced corrosion [MIC]). The 20 percent of piping that is inspected in each five-year interval is in different locations than previously inspected piping.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to perform main drain tests on 20 percent of the standpipes and risers in accordance with NFPA 25 (2011 Edition), Sections 6.3.1.5 and 13.2.5.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Fire Water System Program procedures to specify an annual air flow test of the charcoal filter units that are in scope for license renewal. If obstructions are found, the system shall be cleaned and retested.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to verify the hydrants drain within 60 minutes after flushing or flow testing.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to ensure the training and qualification of the individual performing the evaluation of fire water storage tank coating degradation is in accordance with ASTM International standards endorsed in RG 1.54 guidance, including limitations, if any, identified in RG 1.54 on a particular standard.
4. Detection of Aging Effects	Revise the Fire Water System Program procedures to ensure a fire water tank is not returned to service after identifying interior coating blistering, delamination or peeling unless there are only a few small intact blisters that are not growing in size or number and are surrounded by coating bonded to the substrate as determined by a qualified coating specialist, or the following actions are performed: • Blistering in excess of a few small intact blisters that are not growing in size or number, or blistering not completely surrounded by coating bonded to the substrate is removed. • Delaminated or peeled coating is removed. • The exposed underlying coating is verified securely bonded to the substrate as determined by an adhesion test endorsed by RG 1.54 at a minimum of three locations. • The outermost coating is feathered, and the remaining outermost coating is determined securely bonded to the coating below at a minimum of three locations adjacent to the defective area via an adhesion test endorsed by RG 1.54. • Ultrasonic testing is performed where there is evidence of pitting or corrosion to ensure the tank meets minimum wall thickness requirements. (continued)

Element Affected	Enhancement
4. Detection of Aging Effects (continued)	• An evaluation is performed to ensure downstream flow blockage is not a concern. • A follow-up inspection is scheduled within two years and every two years after that until the coating is repaired, replaced, or removed.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to determine the extent of coating defects on the interior of the fire water tanks by using one or more of the following methods when conditions such as cracking, peeling, blistering, delamination, rust, or flaking are identified during visual examination. • Lightly tapping and scraping the coating to determine the coating integrity. • Dry film thickness measurements at random locations to determine overall thickness of the coating. • Wet-sponge testing or dry film testing to identify holidays in the coating. • Adhesion testing in accordance with ASTM D3359, ASTM D4541, or equivalent testing endorsed by RG 1.54 at a minimum of three locations. • Ultrasonic testing where there is evidence of pitting or corrosion to determine if the tank thickness meets the minimum thickness criteria.
4. Detection of Aging Effects	Revise Fire Water Program procedures to inspect, test and maintain pressure-reducing valves FPW-RV2A/B, FPW-RV113 and FPW-RV386 in accordance with the requirements of Chapter 13 of NFPA 25 (Refer to NFPA 25 (2011 Edition), Section 6.3.1.4).
6. Acceptance Criteria	Revise Fire Water System Program procedures to include acceptance criteria of no abnormal debris (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Signs of abnormal corrosion or blockage will be removed, and its source and extent of condition determined and corrected. The condition will be entered into the corrective action program.

Element Affected	Enhancement
6. Acceptance Criteria	Revise Fire Water System Program procedures to include the following acceptance criteria for the fire water tanks' interior coating: • Indications of peeling and delamination are not acceptable. • Blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including limitations, if any, identified in RG 1.54 associated with use of a particular standard. Blisters should be limited to a few intact small blisters that are not growing in number or size, and are completely surrounded by sound coating/lining bonded to the substrate. Blister size and frequency should not be increasing between inspections (e.g., reference ASTM D714-02, "Standard Test Method for Evaluating Degree of Blistering of Paints"). • Indications such as cracking, flaking, and rusting are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54 including limitations, if any, identified in RG 1.54 associated with use of a particular standard. • As applicable, wall thickness measurements, projected to the next inspection, meet design minimum wall requirements. • Coating meets the plant-specific design requirements for the coating/lining and substrate for the fire water tanks.
7. Corrective Action	Revise Fire Water System Program procedures to specify replacement of sprinkler heads that show signs of leakage, excessive loading, or corrosion.
7. Corrective Action	Revise Fire Water System Program procedures to perform an obstruction evaluation if any of the following conditions exist: • There is an obstructive discharge of material during routine flow tests. • An inspector's test valve is clogged during routine testing. • Foreign material is identified during internal inspections. • Sprinkler heads are found clogged during removal or testing. • Pin-hole leaks are identified in fire water piping. • After an extended fire water system shutdown (greater than one year).

Element Affected	Enhancement
7. Corrective Action	Revise Fire Water System Program procedures to evaluate for MIC if tubercules or slime are identified during internal inspections of fire water piping.

Operating Experience

The following operating experience provides objective evidence that the Fire Water Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- During the first quarter of 2012, a quality assurance audit of the Fire Protection Program was conducted. Through a review of program scope elements, personnel interviews, and audit observations, the audit team concluded the program is effective. The audit team identified no issues that challenged continued performance and the ability to maintain compliance with regulatory requirements. All 11 of the audit scope elements evaluated were deemed satisfactory.

  During the audit, a field walk down was conducted of 13 fire zones in four different buildings in the power block. Personnel verified appropriate detection and suppression equipment was staged as specified by the fire-fighting plans. The equipment appeared well maintained and readily accessible. Hose stations, fire extinguishers, sprinklers, and fire water piping and valves were walked down. A minor procedural discrepancy was noted, and the procedure was revised.

- In 2012, a fire deluge valve was found with a small leak through the bell drip valve into a tell-tale drain line to the floor. In 2015, the valve was found with a slightly larger leak. In both instances, the leak had no impact on valve functionality, and the condition was entered into the normal work management process.

- During the first quarter of 2014, a quality assurance audit of the Fire Protection Program was conducted. Through a review of program scope elements, personnel interviews, and audit observations, the audit team concluded the program is marginally effective in implementing activities that affect quality. The audit team identified issues that challenged continued performance and the ability to maintain compliance with regulatory requirements. One finding involved components of the fire water system:

  - The "Compensatory Measures" scope element was rated unsatisfactory based on the untimely repair and return to service of fire protection equipment.

  A review of the timeliness of repairing and returning fire protection equipment to service determined that guidance was vague and the prioritization of fire protection corrective maintenance was inconsistent. Corrective actions included the following:

- Review of the list of fire protection work orders associated with a Technical Requirement Manual Limiting Condition for Operation that required a fire watch to ensure appropriate prioritization.

- Creation of a fire marshal position in Operations to monitor the condition of fire protection equipment and execution of fire protection program elements.

- Revisions to work management standards for prioritization of work orders for fire protection deficiencies.

- Incorporation of lessons learned into appropriate training.

These actions have been completed.

- In 2015, a cross-tie valve for the fire water header to the fuel building was found with a packing leak. This condition was entered into the normal work management process.

- The program health report for the fourth quarter of 2015 identified challenges with fire protection infrastructure (valves, piping and fire detection system) and with fire protection staffing.

  - Fire protection infrastructure upgrade plans are in progress.

  - A backup fire protection engineer was hired in preparation for the retirement of the current fire protection engineer.

- In 2015, external inspections of the fire water storage tanks (A and B) were performed. No discrepancies were identified with either tank. A fire water outlet header drain valve was found to have a small leak. This condition was entered into the normal work management process.

- In 2015, the Technical Specification-related fire hose station water flow test and hose hydro inspection was performed. All hoses were replaced. All hose rack flow tests were acceptable.

- During the performance of the fire protection sprinkler system functional test outside the protected area in March 2016, three sprinkler systems did not pass the water motor alarm sound-off test. Two had no flow and no alarm. The third had flow but no alarm. One area had a leak in the piping that prevented achieving adequate flow for the test. This condition was entered into the normal work management process.

- In April 2016, fire hose stations were visually inspected. The visual inspection of fire hose stations is performed to assure all required equipment is at stations and hose equipment is free of damage and deterioration. The inspection results were acceptable.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the Fire Water System Program has been effective. The continued application of proven inspection and testing methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Fire Water System Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.21 FLOW-ACCELERATED CORROSION

Program Description

The Flow-Accelerated Corrosion (FAC) Program manages loss of material due to wall thinning caused by FAC for piping and components through (a) performing an analysis to determine systems susceptible to FAC, (b) conducting appropriate analysis to predict wall thinning, (c) performing wall thickness measurements based on wall thinning predictions and operating experience, and (d) evaluating measurement results to determine the remaining service life and the need for replacement or repair of components.

The FAC program also manages wall thinning due to various erosion mechanisms in treated water or steam systems.

The FAC Program relies on implementation of guidelines published by EPRI in NSAC-202L and on internal and external operating experience. The program uses a predictive code for portions of susceptible systems with design and operating conditions that are amenable to computer modeling. Inspections are performed using ultrasonic or other approved testing techniques capable of determining wall thickness. Field measurements are used to corroborate the results of the predictive code and to recalibrate the model as appropriate. The time remaining before the component reaches the minimum allowable wall thickness is predicted using inspection results (i.e., measured data) and other methods to estimate the wear rate.

NUREG-1801 Consistency

The Flow-Accelerated Corrosion Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion, as modified by LR-ISG-2012-01, "Wall Thinning Due to Erosion Mechanisms."

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise FAC Program procedures to manage wall thinning due to erosion mechanisms such as cavitation, flashing, liquid droplet impingement, and solid particle impingement.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise FAC Program procedures to include susceptible locations based on the extent-of-condition reviews in response to plant-specific or industry operating experience.
7. Corrective Actions	Revise FAC Program procedures to (1) evaluate wall thinning due to erosion from cavitation, flashing, liquid droplet impingement, and solid particle impingement when determining a replacement type of material, and (2) ensure piping and components replaced with FAC-resistant material and subject to erosive conditions are not excluded from inspections until effectiveness of piping replacement or other corrective action has been confirmed.

Operating Experience

The following operating experience provides objective evidence that the FAC Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- During Cycle 14 and the 2008 refueling outage, Cycle 15 and the 2009 refueling outage, and Cycle 16 and the 2011 refueling outage, a significant number of inspections were performed on piping and components where flow-accelerated corrosion could compromise plant operations during the following operating cycle. Large bore piping, small bore piping, and other components, including feedwater heaters, were inspected. Inspected components that would not be satisfactory for the following operating cycle were replaced prior to startup from the outage.

- In 2013, measured wall thickness of a feedwater system line was found less than the minimum allowable wall thickness. The condition was evaluated, and a new minimum allowable wall thickness was determined. Since the new minimum allowable wall thickness was less than the measured wall thickness, the piping was acceptable for performing its design and licensing basis function for several additional cycles of operation.

- In 2015, an elbow on a line between regenerative heat exchangers in the RWCU system was found with wall thickness less that the minimum allowable wall thickness. A weld overlay was performed to qualify the line for one cycle of operation, and a work order was generated to replace the line during the 2017 refueling outage.

- The program health report for the fourth quarter of 2015 designated the overall status of the program as excellent. The backup program owner became fully qualified in the second quarter of 2015. Sufficient time was allotted for program improvements. The program has the necessary equipment and established procedures. Corrective actions to piping were completed and sample expansions were performed as necessary during the 2015 refueling outage.

As discussed in element 10 to NUREG-1801, Section XI.M17, this program considers the technical information and industry operating experience provided in NRC IE Bulletin 87-01, NRC IN 92-35, IN 95-11, IN 2006-08, IN 89-53, IN 97-84, IN 91-18, IN 93-21, IN 97-84, and IN 99-19, and Licensee Event Report (LER) 483/1999-003-01, LER 277/2006-003-00, LER 237/2007-003-00, and LER 254/2009-004-00.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrate that the Flow-Accelerated Corrosion Program has been effective. The continued application of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Flow-Accelerated Corrosion Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.22 INSERVICE INSPECTION

Program Description

The Inservice Inspection (ISI) Program manages cracking, loss of material, and reduction in fracture toughness for ASME Class 1, 2, and 3 pressure-retaining components including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting using periodic volumetric, surface, and visual examination and leakage testing as specified in ASME Section XI code, 2001 Edition, 2003 addendum. Additional limitations, modifications, and augmentations described in 10 CFR 50.55a are included as a part of this program. Every 10 years this program is updated to the latest ASME Section XI code edition and addendum approved by the NRC in accordance with 10 CFR 50.55a. Repair and replacement activities for these components are covered in Subsection IWA of the ASME code edition of record.

NUREG-1801 Consistency

The Inservice Inspection Program is consistent with the program described in NUREG-1801, Section XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the ISI Program will continue to be effective in assuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- Inspections of in-core dry tubes conducted in 1992, 1996, 1999, and 2003 did not identify indications. Inspections in 2008 found indications for five dry tubes. No further indications were identified during the 2009 inspections. Inspections in 2011 found no indications. Inspections in 2013 found indications and wear.

  The indications identified during the 2008 examinations were evaluated and found acceptable for one additional cycle of operation. The tubes with indications were replaced in 2009. The indications identified in 2013 were evaluated and found acceptable for one additional cycle. The tubes with indications were replaced in 2015. The original equipment manufacturer evaluated the worn tubes identified in 2013 and found them acceptable.

No repairs have been performed on the in-core housings, guide tubes or dry tubes. However, River Bend began replacing its 45 pre-1986 dry tubes in 2009 after inspection revealed crack-like indications in five dry tubes. As of the end of the 2015 refueling outage, 29 dry tubes had been replaced. Sixteen pre-1986 dry tubes remain pending future replacement.

- The 2006 refueling outage ISI inspection package included abstracts of examinations and tests. The following corrective measures related to the ISI Program were documented:
  - Two weld "build up" repairs on service water valve bodies. Both valves retained the ability to perform their intended functions.
  - Replaced valve bottom plug. This leak on a main steam drain isolation valve (outboard) would not have prevented main steam line isolation.
  - Replaced leaking lube oil return line on the Division I SDG caused by a cracked weld. The apparent cause of the failure was a weld defect aggravated by the support design causing a fatigue crack. The as-found leak did not affect the operation of the diesel generator.
- In 2011, a focused self-assessment was performed for the ISI Program. The assessment consisted of a review of program documents and interviews with program personnel. Adequate performance of the ISI Program was verified. RBS has demonstrated compliance with applicable regulations, codes and standards. No areas for improvement were identified. Two performance deficiencies, 20 negative observations, 5 strengths, 21 positive observations, and 21 observations (enhancement opportunities) were noted. The team concluded that the program was being effectively implemented.
- In 2013, magnetic particle examination of a weld in the main steam system found no relevant indications, and a liquid penetrant examination was performed on an integral attachment for a reactor recirculation pump with acceptable results.
- The 2015 program health report found three issues—two concerning personnel availability and a third entailing database changes that, while not impacting program performance, were not being timely entered. Remaining indicators were rated as excellent. Actions were in place to resolve the personnel issues.
- In 2016, a VT-2 visual examination for system leakage was performed for several pipe lines in the service water system. The results were acceptable.
- The 2016 program health report found that while personnel availability was still impacting the program, the trend was improving. Outstanding database changes were being resolved. Overall program health was rated as excellent.

As discussed in element 10 to NUREG-1801, Section XI.M1, this program considers the technical information and industry operating experience provided in NRC Bulletin 80-13, IN 95-17, GL 94-03, NUREG 1544, IN 89-80, LER 50-249/99-00301, IN 88-03, IN 92-57, and LER 50-219/98-014-00.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, provide reasonable assurance that the Inservice Inspection Program will remain effective. The continued application of these proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Inservice Inspection Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.23 INSERVICE INSPECTION – IWF

Program Description

The Inservice Inspection (ISI) – IWF (ISI-IWF) Program performs periodic visual examinations of ASME Class 1, 2, and 3 piping and component supports to determine general mechanical and structural condition or degradation of component supports. The examinations include verification of clearances, settings and physical displacements, and identification of loose or missing parts, debris, corrosion, wear, erosion, or the loss of integrity at welded or bolted connections. RBS MC component supports are addressed under the ASME Section XI, Subsection IWE program. The ISI-IWF Program is implemented through plant procedures which provide administrative controls, including corrective actions, for the conduct of activities that are necessary to fulfill the requirements of ASME Section XI, as mandated by 10 CFR 50.55a. The monitoring methods are effective in detecting the applicable aging effects, and the frequency of monitoring provides reasonable assurance that significant degradation can be identified prior to a loss of intended function.

RBS is in its third 10-year ISI inspection interval. The ISI-IWF Program was developed in accordance with ASME Section XI, 2001 Edition through the 2003 Addenda as approved by 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4)(ii), the program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

The selection of component supports subject to examination is based upon Table IWF-2500-1, Examination Category F-A. The number of piping supports selected for inspection is based on consideration of ASME classification. The largest sample size is specified for ASME Class 1 piping supports (25 percent) and decreases for less critical supports (15 percent for ASME Class 2, and 10 percent for ASME Class 3). For component supports other than Class 1, 2, and 3 piping supports, a sampling process is not used; rather 100 percent of these supports is examined each ISI inspection interval. For multiple components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components must be examined.

Discovery of support deficiencies during regularly scheduled inspections is entered in the corrective action program. If the deficiencies fail to meet acceptance standards of IWF 3400, the scope of inspection is expanded to include additional supports in order to ensure the full extent of the deficiencies is identified. The method of inspection is by visual examination in accordance with IWF-2500 requirements.

Visual examinations are conducted to determine the general mechanical and structural condition of component supports. The VT-3 examination can also be used to detect loss of material and cracking of elastomeric vibration isolation elements or the loss of integrity at welded or bolted connections.

The ISI-IWF Program includes procedures that ensure the selection of bolting material, the selection of installation torque or tension, and the use of lubricants and sealants are appropriate for the intended purpose. These procedures use recommendations delineated in NUREG-1339 and industry recommendations delineated in the Electric Power Research Institute (EPRI) NP-5769, NP-5067, and TR-104213 to ensure proper specification of bolting material, lubricant, and installation torque. Plant procedures prohibit the use of lubricants containing molybdenum disulfide. Since the use of this type of lubricant is prohibited in plant procedures and plant procedures provide the technical guidance for installation requirements (lubricants or compounds used in threaded joints shall be suitable for the service conditions and shall not react unfavorably with the joint materials), stress corrosion cracking for high-strength structural bolting material, i.e. ASTM A325 and A490, is not plausible. Therefore, volumetric examination is not included in the program.

Identified degradation that could compromise the component support intended function is entered into the corrective action program for evaluation and correction, if necessary, to ensure the intended function is maintained.

The ISI-IWF Program implementing procedures specify acceptance criteria and corrective actions. Supports that require corrective actions are re-examined during the next inspection period consistent with IWF-2420.

NUREG-1801 Consistency

The Inservice Inspection – IWF Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.S3, ASME Section XI, Subsection IWF.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
2. Preventive Actions	Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

Element Affected	Enhancement
4. Detection of Aging Effects	Revise plant procedures to specify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts and bolts, and cracking of concrete around the anchor bolts.
5. Monitoring and Trending	Revise plant procedures to include assessment of the impact on the inspection sample, in terms of sample size and representativeness, if components that are part of the sample population are re-worked.
6. Acceptance Criteria	Revise plant procedures to specify the following conditions as unacceptable. • Loss of material due to corrosion or wear that reduces the load bearing capacity of the component support. • Debris, dirt, or excessive wear that could prevent or restrict sliding of the sliding surfaces as intended in the design basis of the support. • Cracked or sheared bolts, including high strength bolts, and anchors.

Operating Experience

The following operating experience provides objective evidence that the ISI-IWF Program will continue to be effective in assuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- The 2006 refueling outage ISI inspection package included abstracts of examinations and tests. The following corrective measures related to the ISI-IWF Program were documented:
  - Evaluation of missing lock nut on an RHR system pipe support. The support was determined to be fully functional with the missing lock nut.
  - Readjusted spring hanger. The affected RHR pump test return/minimum flow line was determined to retain the capability of performing its function even assuming the spring hanger failed.
- In 2011, visual examinations (VT-3) were performed for pipe support struts in the residual heat removal system. No deficiencies were noted.

- In 2013, visual examinations (VT-3) were performed for a pipe support strut in the residual heat removal system and one in the reactor core isolation cooling system. No deficiencies were noted.

- In 2015, during a validation of the components contained in the ISI Program database, a set of 29 pipe rupture restraints were found not to be included. The omission appears to have occurred during the development of the first ISI interval program plan. Because they perform a support function, they should be included in the ISI Program and a percentage inspected under the requirements of ASME Code, Section XI, subsection IWF. Component identifications for the restraints were entered in the site component database, and eight inspections were scheduled for the 2017 refueling outage.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrates that the ISI-IWF Program has been effective. The continued application of these proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The ISI-IWF Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.24 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

Cranes and hoists in the scope of license renewal are monitored in accordance with the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program. Related activities consist of periodic inspections and preventive maintenance that are relied upon to manage loss of material due to corrosion, loose bolting or rivets, and rail wear of cranes and hoists within the scope of license renewal and subject to aging management review. The activities entail visual examinations and functional testing to ensure that cranes and hoists are capable of sustaining their rated loads. The number and the magnitude of lifts made by the hoist or crane are also reviewed. The functional test examinations are performed on active components of the crane to ensure proper functionality and are not credited for managing the effects of aging of passive components of cranes and hoists.

The scope of the program includes structural components, including structural bolting, that make up the bridge, the trolley, lifting devices, and crane rails and includes cranes and hoists that meet the provisions of 10 CFR 54.4(a)(1) and (a)(2) and of NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants.*

The aging management activities specified in this program will utilize the guidance provided in ASME Safety Standard B30.2, "Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)."

NUREG-1801 Consistency

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M23, Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
3. Parameter Monitored or Inspected	Revise plant procedures to specify that the program manages the effects of aging for the crane rails for wear; manages the effects of aging for bridge, trolley and hoists structural components for deformation, cracking, and loss of material due to corrosion; and manages the effects of aging for structural connections for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity.
4. Detection of Aging Effects	Revise plant procedures to specify inspection frequency will be in accordance with ASME B30.2 or other appropriate standard in the ASME B30 series. The inaccessible or infrequently used cranes and hoists will be inspected prior to use. Bolted connections will be visually inspected for loose or missing bolts, nuts, pins or rivets at the same frequency as crane rails and structural components.
6. Acceptance Criteria	Revise plant procedures to specify the acceptance criteria for 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.
7. Corrective Action	Revise plant procedures to specify that maintenance and repair activities will utilize the guidance provided in ASME B30.2 or other appropriate standard in the ASME B30 series.

Operating Experience

The following operating experience provides objective evidence that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program will be effective in managing the effects of aging such that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- Fuel building crane inspections in 2013 and 2014 were completed satisfactorily. The inspections included verifying runway rail heads were not cracked, spalled or mashed over to sharp edge; runway rails were clean, free of foreign materials, and anchored properly with no looseness or other abnormal conditions; the bridge structure bolts and rivets were tight; and bridge structural welds had no cracks or deformations.

- Radwaste building crane inspections in 2014 and 2015 were completed satisfactorily. Inspections of the monorail structure and the carrier and hoist structure included verifying bolts and rivets were tight, no cracks or deformations in the structural welds, and no unusual wear, flat spots, or cracks in the wheels.

- During inspections in 2014, the main turbine crane was found with broken rail stop blocks. The crane was still functional. The identified condition involved the wooden stop blocks on the crane rails (i.e., bumpers) and did not impact the structural integrity of the crane. The condition was entered into the normal work management process.

- During an inspection of the horizontal support beams for the turbine overhead crane rails in 2015, two potential cracks were identified. NDE (magnetic particle examination) was performed to determine whether cracks actually existed. The NDE found no indication of cracking. The indications were determined to be surface scratches or scuffs.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program has been effective. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

<u>Conclusion</u>

The Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.25 INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

Program Description

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program that will manage cracking, loss of material, reduction of heat transfer, and change in material properties using representative sampling and opportunistic visual inspections of the internal surfaces of metallic and elastomeric components in environments of air – indoor, air – outdoor, condensation, exhaust gas, raw water, and waste water. Internal inspections will be performed during periodic system and component surveillances or during the performance of maintenance activities when the surfaces are accessible for visual inspection.

Where practical, the inspections will focus on the bounding or leading components most susceptible to aging because of time in service and severity of operating conditions. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population will be inspected. Opportunistic inspections will continue in each period even if the minimum sample size has been inspected.

For metallic components, visual inspection will be used to detect evidence of loss of material and reduction of heat transfer. For non-metallic components, visual inspections will be used to detect surface irregularities. Visual examinations of elastomeric components will be accompanied by physical manipulation or pressurization such that changes in material properties are readily observable. The sample size for physical manipulation will be at least 10 percent of accessible surface area.

Specific acceptance criteria will be as follows:

- Stainless steel: clean surfaces, shiny, no abnormal surface condition.
- Metals: no abnormal surface condition.
- Elastomers: a uniform surface texture and color with no cracks, no unanticipated dimensional change, and no abnormal surface conditions.

Conditions that do not meet the acceptance criteria will be entered into the corrective action program for evaluation. Indications of relevant degradation will be evaluated using design standards, procedural requirements, current licensing basis, and industry codes or standards.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be consistent with the program described in NUREG-1801, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program. Industry operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

As discussed in element 10 to NUREG-1801, Section XI.M38, inspections of internal surfaces during the performance of periodic surveillance and maintenance activities have been in effect at many utilities in support of plant component reliability programs. These activities have proven effective in maintaining the material condition of plant systems, structures, and components. The elements of these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program will be consistent with the program described in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.26 MASONRY WALL

Program Description

The Masonry Wall Program is based on guidance provided in Information Notice (IN) 87-67, "Lessons Learned from Regional Inspections of Licensee Actions in Response to IE Bulletin 80-11." The program manages aging effects so that the evaluation basis established for each masonry wall within the scope of license renewal remains valid through the period of extended operation. RBS performed a review of IE Bulletin 80-11, "Masonry Wall Design," and responded to the NRC that RBS did not have seismic Category I masonry (concrete block) walls. The program includes visual inspection of masonry walls that perform intended functions as defined in 10 CFR 54.4. Masonry walls included are 10 CFR 50.48 required masonry walls, radiation shielding masonry walls, and masonry walls with the potential to affect safety-related components. The periodic visual inspection of masonry walls within the scope of license renewal will detect aging effects of loss of material and cracking of masonry units and mortar. The aging effects identified that could impact a masonry wall's intended function or potentially invalidate its evaluation basis are entered into the corrective action program to determine the necessary corrective actions, which could include further analysis, repair, or replacement. The Structures Monitoring Program (Section B.1.41) manages the effects of aging on structural steel components, such as steel edge supports and steel bracing of masonry walls.

Masonry walls are visually examined at least once every five years to ensure there is no loss of intended function.

NUREG-1801 Consistency

The Masonry Wall Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.S5, Masonry Walls Program.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise plant procedures to ensure masonry walls located in in-scope structures are included in the scope of the Masonry Wall Program.

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise plant procedures to include monitoring gaps between the structural steel supports and masonry walls that could potentially affect wall qualification.
4. Detection of Aging Effects	Revise plant procedures to specify that masonry walls will be inspected at least once every five years with provisions for more frequent inspections in areas where significant aging effects (missing blocks, cracking, etc.) are observed to ensure there is no loss of intended function between inspections.
6. Acceptance Criteria	Revise plant procedures to include acceptance criteria for masonry wall inspections that ensure observed aging effects (cracking, loss of material, or gaps between the structural steel supports and masonry walls) do not invalidate the wall's evaluation basis or impact its intended function.

Operating Experience

The following operating experience provides objective evidence that the Masonry Wall Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- A 2005 maintenance rule structures periodic assessment did not note any deficiencies with masonry walls. Overall condition of the structures inspected was acceptable.
- In 2008, a crack was noted at the southwest stairwell of the turbine building at elevation 154 feet. The observed cinder block crack is at the grout between two layers of blocks. An engineering evaluation determined that based on the configuration of the crack, it has no impact on the structural integrity of the wall or the function of the turbine building. Cracked grout was removed from between the cinder blocks and new grout installed.
- A 2013 maintenance rule structures periodic assessment of the drywell, the standby cooling towers, and the heater bay area did not note any deficiencies with masonry walls. The plant structures and equipment inspected were acceptable.
- A maintenance rule structures periodic assessment conducted early in 2014 specifically included an inspection checklist for masonry walls. The inspection identified a broken concrete masonry brick on the west exterior wall of the auxiliary control building. The structure was deemed acceptable with this minor, mainly cosmetic degradation. Nevertheless, personnel repaired the degraded area.

- During work on a new wall penetration in October 2014, cracks were found in mortar between cinder blocks on a wall between a normal switchgear room and controlled access at the T-tunnel. The wall is a fire barrier rated for three hours. The crack was described as minor in nature. Evaluations determined that the crack had no effect on the ability of the building and structure to perform the required fire barrier function and it posed no structural or fire protection concern. The crack was monitored for propagation during penetration work nearby, and no further cracking was observed.

As discussed in element 10 to NUREG-1801, Section XI.S5, this program considers the technical information and industry operating experience provided in IEB 80-11, GL 87-02, IN 87-67, and NUREG-1522.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the Masonry Wall Program has been effective. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Masonry Wall Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.27 NON-EQ ELECTRICAL CABLE CONNECTIONS

Program Description

The Non-EQ Electrical Cable Connections Program is a new one-time inspection program that provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections are maintained consistent with the current licensing basis through the period of extended operation. Cable connections included are those connections in the scope of license renewal susceptible to age-related degradation resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation that are not subject to the environmental qualification requirements of 10 CFR 50.49.

This program provides for one-time inspections that will be completed prior to the period of extended operation on a sample of connections. The factors considered for sample selection will be application (medium and low voltage, defined as < 35 kV), circuit loading (high loading), connection type, and location (high temperature, high humidity, vibration, etc.). The representative sample size will be based on 20 percent of the connection population with a maximum sample of 25.

Cable connections are used to connect cable conductors to other cables or electrical devices. Connections associated with cables within the scope of license renewal are considered for this program. 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 aging management program focuses on the metallic parts of the electrical cable connections. This program provides a one-time inspection, on a sampling basis, to confirm the absence of age-related degradation of cable connections resulting in increased connection resistance due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation. This program does not apply to the high voltage (> 35 kV) switchyard connections.

Metal enclosed bus (MEB) does not have a license renewal intended function at RBS, so there are no aging effects that require management from thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation on the metallic parts of MEB connections. Therefore, MEB connections are not included in this program.

Electrical cable connections exposed to appreciable ohmic or ambient heating during operation may experience increased connection resistance caused by repeated cycling of connected loads or cycling of the ambient temperature environment. Bolted connectors, splices, and terminal blocks may loosen if subjected to significant thermally induced cyclic stress.

The design of these connections will account for the stresses associated with ohmic heating, thermal cycling, and dissimilar metal connections. Therefore, while these stressors/mechanisms should not be a significant issue, confirmation of the lack of these effects is warranted.

Inspection methods may include thermography, contact resistance testing, or other appropriate quantitative test methods without removing the connection insulation, such as heat shrink tape, sleeving, or insulating boots.

These inspections will be performed prior to the period of extended operation.

NUREG-1801 Consistency

The Non-EQ Electrical Cable Connections Program will be consistent with the program described in NUREG-1801, Section XI.E6, Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Non-EQ Electrical Cable Connections Program is a new, one-time inspection program. Industry operating experience will be considered in the implementation of this program.

A review of site-specific operating experience related to cable connections did not reveal any issues with cable connections that perform a license renewal intended function. However, the following events were noted. The site-specific operating experience did not identify any items that were not discovered as part of planned maintenance prior to the failure of the connection, nor does operating experience indicate a need for a periodic aging management program.

- During a system engineering walkdown of station batteries in February 2014, corrosion was found on several cells of an information handling system battery. The condition was corrected using normal work processes to clean corrosion and replace inter-cell connections. Inter-cell connection resistance values did not exceed acceptable values.

- During a system engineering walkdown of station batteries in November 2014, corrosion was found on one cell of the information handling system battery. This cell was not one of the cells identified earlier in the year. It appeared that the corrosion was a result of post seal leakage and exposed copper on a square washer. An evaluation determined that the corrosion could only be coming from the terminal plate or the square washer, as those are the only pieces with copper. The condition was corrected using normal work processes to clean corrosion. Post-maintenance cell readings were within specifications.

The elements of the program inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and have been used effectively at RBS in other programs.

As discussed in element 10 to NUREG-1801, Section XI.E6, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, SAND96-0344, IEEE Std. 1205-2000, EPRI 109619, EPRI 104213, NEI White Paper on AMP XI.E6, Final License Renewal Interim Staff Guidance LR-ISG-2007-02, Staff Response to the NEI White Paper on AMP XI.E6, Licensee Event Report (LER) 3612007005, LER 3612007006 and LER 3612008006.

The Non-EQ Electrical Cable Connections Program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging are being managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Non-EQ Electrical Cable Connections Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.28 NON-EQ INACCESSIBLE POWER CABLES (≥ 400 V)

Program Description

The Non-EQ Inaccessible Power Cables (≥ 400 V) Program is a new condition monitoring program that will manage the aging effect of reduced insulation resistance on inaccessible power cables (≥ 400 V) that have a license renewal intended function. The cables included in this program are routed underground.

The Non-EQ Inaccessible Power Cables (≥ 400 V) Program will include periodic actions to minimize inaccessible cable exposure to 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). In this program, inaccessible power cables (≥ 400 V) exposed to significant moisture will be tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies are adjusted based on test results and operating experience. The specific type of test performed is a proven test for detecting deterioration of the cable insulation.

The program will include periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspections for water after event-driven occurrences, such as flooding, will be performed. The inspections will include direct observation that cables are not wetted or submerged; that cables, splices and cable support structures are intact; and dewatering systems (i.e., sump pumps) and associated alarms, if applicable, operate properly. Inspection frequency will be increased as necessary based on evaluation of inspection results.

A proven, commercially available test will be used for detecting deterioration of the insulation system due to wetting or submergence for inaccessible power cables (≥ 400 V) included in this program, 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.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Non-EQ Inaccessible Power Cables (≥ 400 V) Program will be consistent with the program described in NUREG-1801, Section XI.E3, Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Non-EQ Inaccessible Power Cables ($\geq$ 400 V) Program is a new program. Industry and plant-specific operating experience will be considered when implementing this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

The RBS response to GL 2007-01 identified one inservice cable failure. No formal root cause analysis was performed. Since this failure occurred concurrent with a failure of the associated station service transformer, it is suspected that the cable insulation was stressed beyond design limits by the transformer failure. The failed cable does not have a license renewal intended function.

A review of RBS operating experience since the GL 2007-01 response did not identify other cable failures. The following operating experience with cables and manholes was reviewed.

- In 2009, the NRC resident inspector identified a concern related to equipment in a manhole that contained water. An investigation was conducted to identify the site's cables routed via manholes that might be impacted due to submergence. Manholes were identified and added to the equipment database so that periodic preventive maintenance tasks could be established to inspect the manholes for water and pump down as necessary to protect the underground medium-voltage maintenance rule cables from water.
- In 2014, the 35 kV underground cable between a site fused disconnect switch and a Fancy Point substation transformer failed to meet tan delta acceptance criteria. The fuses were verified good. This cable is inside the substation and belongs to the transmission and distribution (T&D) group and is outside the scope of the RBS work management process. An assignment was given to the switchyard coordinator to notify the T&D inspector of the condition.
- An engineering inspection in April 2015 found degradation of electrical penetration sealant such that gaps existed between the penetration sleeves and the concrete wall of a manhole. This condition was addressed using normal work processes.
- In October 2015, condition reports were initiated for two electrical manholes found with water that was subsequently pumped out. These reports were initiated for trending.

As discussed in element 10 of NUREG-1801, Section XI.E3, this program considers the technical information and industry operating experience provided in NUREG/CR-5643; IEEE Std. 1205-2000; SAND96-0344; EPRI 109619; EPRI 103834-P1-2; NRC IN 2002-12; NRC GL 2007-01; NRC GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, Flood Protection Measures; NRC Inspection Procedure, Attachment 71111.01, Adverse Weather Protection; RG 1.211, Rev. 0; and NUREG/CR-7000.

The Non-EQ Inaccessible Power Cable (≥ 400 V) Program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Non-EQ Inaccessible Power Cables (≥ 400 V) Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.29 NON-EQ INSULATED CABLES AND CONNECTIONS

Program Description

The Non-EQ Insulated Cables and Connections Program is a new condition monitoring program that provides reasonable assurance the intended functions of insulated cables and connections exposed to adverse localized environments caused by heat, radiation and moisture can be maintained consistent with the current licensing basis through the period of extended operation. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the plant design environment for the cable or connection insulation materials.

Accessible insulated cables and connections within the scope of license renewal installed in an adverse localized environment will be visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination, indicating signs of reduced insulation resistance. The program sample consists of all accessible cables and connections in localized adverse environments. This program sample of accessible cables will represent, with reasonable assurance, all cables and connections in the adverse localized environment.

An adverse localized environment is a plant-specific condition that will be determined based on the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation material located at RBS within a plant space. Adverse localized environments can be identified through the use of an integrated approach. This approach may include, but is not limited to, (a) the review of Environmental Qualification (EQ) zone maps that show radiation levels and temperatures for various plant areas, (b) consultations with plant staff who are cognizant of plant conditions, (c) utilization of infrared thermography to identify hot spots on a real-time basis, and (d) the review of relevant plant-specific and industry operating experience. In addition, a survey method focused on plant-wide areas to determine potential adverse localized environments could be used.

This program will visually inspect accessible cables in an adverse localized environment at least once every 10 years, with the first inspection prior to the period of extended operation.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Non-EQ Insulated Cables and Connections Program will be consistent with the program described in NUREG-1801, Section XI.E1, Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Non-EQ Insulated Cables and Connections Program is a new program. Industry operating experience will be considered in the implementation of this program. Plant operating experience for this program will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

A review of RBS operating experience for insulated cables and connections identified the following.

- In 2009, a break in a cable jacket was observed for a solenoid valve associated with a safety relief valve. The conductor's insulation appeared to be intact. The condition was addressed by normal work processes.
- In 2012, during a motor termination lead inspection involving power cables to a circulating water pump, indentations were noted on the jacket of two cables entering the motor termination box. The indentations were due to contact with the conduit edge where the cables enter the motor termination box. Cable jackets are for physical protection of the cable and are not credited with any insulating properties. The cable insulation appeared intact. The condition was addressed by normal work processes.

As discussed in element 10 to NUREG-1801, Section XI.E1, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, and EPRI TR-109619.

The RBS program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Non-EQ Insulated Cables and Connections Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.30 NON-EQ SENSITIVE INSTRUMENTATION CIRCUITS TEST REVIEW

Program Description

The Non-EQ Sensitive Instrumentation Circuits Test Review Program is a new performance monitoring program that will manage the aging effects of applicable cables in the neutron monitoring and process radiation monitoring systems or sub-systems.

The Non-EQ Sensitive Instrumentation Circuits Test Review Program provides reasonable assurance that the intended functions of sensitive, high-voltage, low-signal cables exposed to adverse localized equipment environments caused by heat, radiation and moisture (i.e., neutron flux monitoring instrumentation and process radiation monitoring) can be maintained consistent with the current licensing basis through the period of extended operation.

Most sensitive instrumentation circuit cables and connections are included in the instrumentation loop calibration at the normal calibration frequency, which provides sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation loop performance. The review of calibration results or findings of surveillance testing programs will be performed once every 10 years, with the first review occurring before the period of extended operation.

For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation system (such as insulation resistance tests or time domain reflectometry) will occur at least once every 10 years, with the first test occurring before the period of extended operation.

Applicable industry standards and guidance documents are used to delineate the program. This program will consider the technical information and guidance provided by the industry (NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, and EPRI TR 109619).

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Non-EQ Sensitive Instrumentation Circuits Test Review Program will be consistent with the program described in NUREG-1801, Section XI.E2, Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Non-EQ Sensitive Instrumentation Circuits Test Review Program is a new program. Industry operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the RBS 10 CFR 50 Appendix B quality assurance program.

A review of RBS operating experience for sensitive instrumentation circuits identified the following.

- In 2014, a condition report was initiated on an average power range monitor (APRM) that caused a spurious Division 1 half scram. The APRM was bypassed and the half scram reset. This was a recurring issue with this APRM. Based on an evaluation of the most likely cause, the APRM cleaning preventive maintenance task was performed to include cleaning the area where debris was suspected. No shorted condition could be located following the cleaning. The APRM was returned to service and monitored. No additional spurious half scrams occurred during the monitoring time frame, and the condition report was closed.

As discussed in element 10 to NUREG-1801, Section XI.E2, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, EPRI TR-109619, and NRC IN 97-45 and its Supplement 1.

The Non-EQ Sensitive Instrumentation Circuits Test Review will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Non-EQ Sensitive Instrumentation Circuits Test Review Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.31 OIL ANALYSIS

Program Description

The Oil Analysis Program ensures that loss of material and reduction of heat transfer are not occurring by maintaining the quality of the lubricating oil. The program ensures that contaminants (primarily water and particulates) are within acceptable limits. Testing activities include sampling and analysis of lubricating oil for contaminants. The presence of water can indicate in-leakage, and particulates can be indicative of corrosion products.

The One-Time Inspection Program (Section B.1.32) uses inspections or non-destructive evaluations of representative samples to verify that the Oil Analysis Program has been effective at managing the aging effects of loss of material and reduction of heat transfer.

NUREG-1801 Consistency

The Oil Analysis Program is consistent with the program described in NUREG-1801, Section XI.M39, Lubricating Oil Analysis.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Oil Analysis Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2011, a quality assurance audit included the oil analysis lab. The audit scope element for the oil analysis lab was rated unsatisfactory based on oil analyses not performed as prescribed by station procedure. This practice hampered trending and jeopardized equipment reliability analyses. Contributing to this weakness was a lack of laboratory equipment necessary to perform the analyses. The affected department conducted multiple department "stand downs" to address procedural compliance, developed a formalized process of reviewing procedures to ensure familiarity with the contents, implemented an accountability model, and performed a review of predictive maintenance that resulted in changes to the process of trending oil analyses.

- Following a history of excessive water in the oil of high pressure core spray (HPCS) diesel air start compressors, a modification was initiated in 2011 to install heaters in two of the compressor crankcases. The heater installation was competed in 2013.

- In 2012, a condition was identified with high wear metals in oil for a HPCS diesel air start compressor. The oil was changed. A review of maintenance history and discussion with the system engineer indicated that the compressor had operated reliably without need for a compressor overhaul or replacement since 2006. Ferrography trends were very similar to those from other similar compressors. The compressor vendor indicated that the wear metal values at RBS were not unusual for compressors in this service. Based on the maintenance history review and consultation with the vendor, a new higher alert limit was established for wear metals in the compressor oil.

- In 2013, a quality assurance audit included the oil analysis lab. The audit scope element for the oil analysis lab was rated satisfactory. The requirements were found to be effectively implemented and identified deficiencies had effective corrective actions. A review of the oil analysis process found the finding from the 2011 audit had been adequately resolved. A review of the oil analysis program from six months of data verified implementation was in accordance with procedure requirements.

- In May 2013, a service water cooling pump motor oil sample did not meet analysis criteria for appearance and water content. The oil was subsequently changed. Past sample data was reviewed for the service water pump motors, and no history of water intrusion was noted. Personnel inspected the pump motors to determine if there was a visible water intrusion path. The oil addition caps at the top of the motor appeared degraded when compared to the other two service water pump motors. A task was added to an existing work order to remove the oil fill caps, clean thread or seating areas of debris and rust, reinstall, and seal. No other areas of concerned were found during the inspection.

- In 2015, a sample of service water pump motor oil indicated that the oil needed to be changed due to low viscosity and the age of the oil.

The identification of degradation and initiation of corrective action prior to loss of intended function provide reasonable assurance that the Oil Analysis Program has been effective. The continued application of proven sampling methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Oil Analysis Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.32 ONE-TIME INSPECTION

Program Description

The One-Time Inspection Program is a new program using inspections that verify unacceptable degradation is not occurring or is occurring at a rate such that loss of intended function will not occur during the period of extended operation. The program entails one-time inspection of selected components to accomplish the following:

- Verify the effectiveness of aging management programs designed to prevent or minimize the effects of aging to the extent that they will not cause the loss of intended function during the period of extended operation. The aging effects evaluated are loss of material, cracking, and reduction of heat transfer.
- Confirm the insignificance of an aging effect using inspections that verify unacceptable degradation is not occurring.
- In the event of unacceptable inspection results, trigger additional actions that ensure the intended functions of affected components are maintained during the period of extended operation.

The sample size will be 20 percent of the components in each material-environment-aging effect group up to a maximum of 25 components. Identification of inspection locations will be based on the potential for the aging effect to occur. Examination techniques will be established NDE methods with a demonstrated history of effectiveness in detecting the aging effect of concern, including visual, ultrasonic, and surface techniques. Acceptance criteria will be based on applicable ASME or other appropriate standards, design basis information, or vendor-specified requirements and recommendations. Any indication or relevant condition will be evaluated. The need for follow-up examinations will be evaluated based on inspection results.

The One-Time Inspection Program will not be used for structures or components with known aging mechanisms or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. In these cases a periodic plant-specific inspection will be performed.

The inspections will be performed within the 10 years prior to the period of extended operation.

The program will include activities to verify effectiveness of aging management programs and activities to confirm the insignificance of aging effects as described below.

Diesel Fuel Monitoring Program (Section B.1.15)	One-time inspection activity will verify the effectiveness of the Diesel Fuel Monitoring Program by confirming that unacceptable loss of material and fouling are not occurring.

Oil Analysis Program (Section B.1.31)	One-time inspection activity will verify the effectiveness of the Oil Analysis Program by confirming that unacceptable loss of material, cracking, and fouling are not occurring.
Water Chemistry Control – BWR Program (Section B.1.42)	One-time inspection activity will verify the effectiveness of the Water Chemistry Control – BWR Program by confirming that unacceptable cracking, loss of material, and fouling are not occurring.
Reactor vessel flange leak detection components	One-time inspection activity will confirm that cracking and loss of material are not occurring or are occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of RHR piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of nuclear pressure relief piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.
A representative sample of internal and external surfaces of RCIC piping passing through the waterline region of the suppression pool	One-time inspection activity will confirm that loss of material is not occurring or is occurring so slowly that the aging effect will not affect the component intended function during the period of extended operation.

Inspections will be performed within the 10 years prior to the period of extended operation.

NUREG-1801 Consistency

The One-Time Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M32, One-Time Inspection.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The One-Time Inspection Program is a new program. Industry operating experience will be considered in the implementation of this program.

This program will use inspections that verify unacceptable degradation is not occurring or is minimized to the extent that the loss of intended function will not occur during the period of extended operation. In accordance with the recommendations in NUREG-1801, Revision 2, Section XI.M32, the elements of these inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

The One-Time Inspection Program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The One-Time Inspection Program provides reasonable assurance that the Diesel Fuel Monitoring Program (Section B.1.15), Oil Analysis Program (Section B.1.31), and Water Chemistry Control – BWR Program (Section B.1.42) will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation. The program also provides reasonable assurance of the absence or insignificance of certain aging effects that are not expected to lead to a loss of intended function during the period of extended operation.

B.1.33 ONE-TIME INSPECTION – SMALL-BORE PIPING

Program Description

The One-Time Inspection – Small-Bore Piping Program is a new program that will augment ASME Code, Section XI requirements and is applicable to small-bore ASME Code Class 1 piping and components with a nominal pipe size diameter less than 4 inches (NPS < 4) and greater than or equal to NPS 1 in systems that have not experienced cracking of ASME Code Class 1 small-bore piping. The program can also be used for systems that have experienced cracking but have implemented design changes to effectively mitigate cracking. RBS has not experienced cracking of ASME Code Class 1 small-bore piping due to stress corrosion, cyclical (including thermal, mechanical, and vibration fatigue) loading, or thermal stratification and thermal turbulence.

Since RBS has an extensive operating history (i.e., greater than 30 years), this program provides a one-time volumetric or opportunistic destructive inspection of a 3-percent sample or maximum of 10 ASME Class 1 piping butt weld locations and a 3-percent sample or a maximum of 10 ASME Class 1 socket weld locations that are susceptible to cracking. Volumetric examinations are performed using a demonstrated technique that is capable of detecting the aging effects in the volume of interest. In the event the opportunity arises to perform a destructive examination of an ASME Class 1 small-bore socket weld that meets the susceptibility criteria, then the program takes credit for two volumetric examinations. The program includes pipes, fittings, branch connections, and full and partial penetration welds.

This program includes a sampling approach. Sample selection is based on susceptibility to stress corrosion, cyclic loading (including thermal, mechanical, and vibration fatigue), thermal stratification, thermal turbulence, dose considerations, operating experience, and limiting locations of total population of ASME Class 1 small-bore piping locations.

The program includes measures to verify that degradation is not occurring, thereby either confirming that there are no aging effects requiring management or validating the effectiveness of any existing program for the period of extended operation. If evidence of cracking is revealed by this one-time inspection, it will be entered into the corrective action program to determine extent of condition, and a follow-up periodic inspection will be managed by a plant-specific program.

The inspection will be performed within the six years prior to the period of extended operation.

NUREG-1801 Consistency

The One-Time Inspection – Small-Bore Piping Program will be consistent with the program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The One-Time Inspection – Small Bore Piping Program is a new program. Industry operating experience will be considered in the implementation of this program. As stated in NUREG-1801, Revision 2, Section XI.M35, this program uses volumetric inspection techniques with demonstrated capability and a proven industry record to detect cracking in piping weld and base material.

RBS has not experienced cracking of ASME Code Class 1 small-bore piping less than NPS 4 and greater than or equal to NPS 1 due to stress corrosion, cyclical loading, (including thermal, mechanical, and vibration fatigue), or thermal stratification and thermal turbulence.

The One-Time Inspection – Small Bore Piping Program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The One-Time Inspection – Small-Bore Piping Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.34 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Program Description

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance (PSPM) Program includes periodic inspections and tests to manage aging effects, including cracking, loss of material, reduction of heat transfer, and change in material properties, in cases where no NUREG-1801 program was found appropriate to manage the particular aging effects for specific components. Indications or relevant conditions of degradation detected are evaluated. Inspections occur at least once every six years during the period of extended operation, except as noted below.

Credit for program activities has been taken in the aging management review for the following systems and structures.

Reactor building	Inspect the surface of the inflatable elastomer seal for the upper containment pool gates.
Auxiliary building	Inspect the surface of the inflatable elastomer seal for the spent fuel storage pool gates.
Plant drains system	Visually inspect the internal and external surfaces of pump casings and piping components within sumps to manage loss of material and cracking. Visually inspect the external surface of the pump suction strainer within sumps to manage loss of material.
Service water system	Visually inspect the external surfaces of SWC and SWP pump casings to manage loss of material.
Standby diesel generators	Visually inspect the external surface of heat exchanger (intercooler) tube fins to manage reduction of heat transfer at least once every eight years.
Nonsafety-related systems affecting safety-related systems	Visually inspect the internal surfaces of leak detection system (system code 207) abandoned components (piping, sight glass, and valve body) to manage loss of material.
	Visually inspect the internal surfaces of makeup water system (system code 659) abandoned components (piping and valve body) to manage loss of material. (continued)

Nonsafety-related systems affecting safety-related systems (continued)	Visually inspect the internal surfaces of fuel pool cooling system (system code 602) abandoned components (piping and valve body) to manage loss of material.
	Visually inspect the internal surfaces of reactor water cleanup system (system code 601) abandoned piping components to manage loss of material.
	Visually inspect the internal surfaces of standby service water system (system code 256) abandoned components (piping and valve body) to manage loss of material.
	Visually inspect the internal surfaces of process radiation monitoring system (system code 511) abandoned components (flex hose, heat exchanger, piping, pump casing, sight glass, tubing, and valve body) to manage loss of material.
	Visually inspect the internal surfaces of floor and equipment drains system (system code 609) abandoned piping components to manage loss of material.

Evaluation

1. Scope of Program

The PSPM Program, with regard to license renewal, includes the specific structures and components identified in the aging management reviews as listed in the table above.

2. Preventive Actions

Similar to other condition monitoring programs described in NUREG-1801, the PSPM Program does not include preventive actions.

3. Parameters Monitored/Inspected

The PSPM Program monitors surface condition through visual inspections to identify degradation of the particular structure or component. This program monitors for degradation by (a) inspecting surfaces of elastomeric components and (b) inspecting internal and external surfaces of metallic components.

4. Detection of Aging Effects

Periodic surveillances and preventive maintenance activities provide for component inspections to detect aging effects. Inspection intervals are established such that they provide timely detection of degradation prior to loss of intended functions. Inspection intervals, sample sizes, and data collection methods are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Established inspection methods to detect aging effects of loss of material and cracking include visual inspections for metallic components. Inspection of elastomeric materials to detect change in material properties includes visual inspections while manually flexing the component.

Each inspection occurs at least once every six years, except for diesel component inspections which are performed at least once every eight years. Inspections are performed by personnel qualified to perform the selected technique.

This program is credited with managing cracking, loss of material, reduction of heat transfer, and change in material properties for components fabricated from aluminum, stainless steel, carbon steel, copper alloy, and elastomers in environments of exhaust gas, lube oil, raw water, and waste water.

5. Monitoring and Trending

Periodic surveillance and preventive maintenance activities provide for monitoring and trending of aging degradation. Inspection intervals are established such that they provide for timely detection of component degradation. RBS identifies trends and evaluates for impact on plant performance, equipment reliability, and safety.

6. Acceptance Criteria

PSPM Program acceptance criteria are defined in specific inspection procedures. The acceptance criterion is no indication of relevant degradation. For example, if the specific inspection is monitoring the surface condition, then the acceptance criterion is the absence of unexpected conditions. Identified degradation is evaluated.

7. Corrective Actions

Unacceptable conditions are evaluated. Corrective actions, including root cause determination and prevention of recurrence, are implemented as discussed in Section B.0.3.

8. Confirmation Process

This element is discussed in Section B.0.3.

9. Administrative Controls

This element is discussed in Section B.0.3.

10. Operating Experience

The following operating experience provides objective evidence that the PSPM Program will be effective in managing the effects of aging by identifying problems, initiating corrective action, and implementing program improvements.

- In 2014, a condition report documented a potential adverse trend regarding late non-critical PMs. The basis of the potential trend is three incidents that documented late PMs in the following areas: security equipment, manway inspections, and cranes. An evaluation determined that no adverse process trend exists. The security equipment PM and the manway inspection PM were completed prior to their late date, but paperwork had not been closed. The periodic crane inspection could not be performed due to the crane being tagged out for repairs, but the implementing department did not notify the PM coordinator to suspend the PM per the approved process. In all three cases coaching was provided to the leadership of the implementing departments.
- In 2016, discrepancies were encountered in the emergency diesel generator 18-month PM task instructions, halting preparation for the test run. A review of the history of the PM task shows that it had been recently revised since it was last performed. Following the Engineering review and identification of the PM task changes that were needed, the decision was made to complete the auxiliary equipment PM tasks that were required based on their frequency and reschedule the 18-month diesel generator task. The condition was addressed in a "roll-up" review of human performance issues.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the PSPM Program has been effective. The continued application of proven monitoring methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise PSPM Program procedures as necessary to incorporate the identified activities.
6. Acceptance Criteria	Revise PSPM Program procedures to state that the acceptance criterion is no indication of relevant degradation and that such indications will be evaluated.

Conclusion

The Periodic Surveillance and Preventive Maintenance Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.35 PROTECTIVE COATING MONITORING AND MAINTENANCE

Program Description

The Protective Coating Monitoring and Maintenance Program manages the effects of aging on Service Level I coatings applied to external surfaces of carbon steel and concrete inside containment (e.g., steel containment vessel shell, structural steel, supports, penetrations, and concrete walls and floors). The Protective Coating Monitoring and Maintenance Program is implemented using the guidance provided in ASTM D 5163-08. The program provides an effective method to assess coating condition through visual inspections by identifying degraded or damaged coatings and providing a means for repair of identified problem areas.

Service Level I protective coatings are not credited to manage the effects of aging. Proper monitoring and maintenance of protective coatings inside containment ensures operability of post-accident safety systems that rely on water recycled through the containment. The proper monitoring and maintenance of Service Level I coatings ensures there is no coating degradation that would impact safety functions, for example, by clogging emergency core cooling system suction strainers.

NUREG-1801 Consistency

The Protective Coating Monitoring and Maintenance Program is consistent with the program described in NUREG-1801, Section XI.S8, Protective Coating Monitoring and Maintenance Program.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Protective Coating Monitoring and Maintenance Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2009, the drywell coatings inspection was performed, including areas observed in past outages that required re-coating. The overall condition of drywell coatings was characterized as good. Areas without coatings noted in this inspection were relatively small, and in every case, corrosion was minor surface rust. No pitting or base metal damage was noted on the structures. The exposed carbon steel and minor surface corrosions were judged acceptable as found and also through the next operating cycle.

- In 2011, the drywell coatings inspection identified six locations with loose coating. The condition was entered into the corrective action program, and personnel removed the loose coating. Fourteen other locations with degraded coating were found with the coating sufficiently adhered to the surface and no excessive subsurface degradation. Mitigation of those remaining locations was performed the next refueling outage.

- In 2013, the drywell coatings inspection identified two locations with loose coating. The condition was entered into the corrective action program, and personnel removed the loose coatings during the refueling outage. Five other locations with degraded coating were found with the coating sufficiently adhered to the surface and no excessive subsurface degradation. A task to mitigate the conditions documented for these remaining locations was performed during the next refueling outage.

  Overall, drywell coatings were described as performing well. There were no large areas exhibiting distress, such as blisters, cracking, peeling or flaking. The observed areas of failed coatings were small compared to the overall coated surface area of the drywell. The observed failures were the result of specific conditions at the locations, not due to a general failure of the coating system.

  The cumulative total of 1946.5 square feet of unqualified coatings remained within the procedurally allowed value of 2,000 square feet. Degraded coatings identified during the walk down and the cumulative total of unqualified coatings is significantly less than the 150,000 square feet that is the maximum allowable failed coating area with which the ECCS suction strainers remain capable of performing their design function.

- In 2015, the drywell coatings inspection identified seven different areas near or on the underside of elevation 162'-3" with peeled or delaminated coating. A conservative estimate of 15 square feet of coating was degraded. The noted areas have light surface rust. The condition was entered into the corrective action program, and degraded coating was removed from the affected areas before startup. The coating in other areas of the drywell was found sufficiently adhered to the substrate with no excessive subsurface degradation. Accessible elevations of the drywell were found to be in very good condition.

As discussed in element 10 to NUREG-1801, Section XI.S8, this program considers the technical information and industry operating experience provided in IN 88-82, Bulletin 96-03, GL 04-02, GL 98-04, and RG 1.54.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrate that the Protective Coating Monitoring and Maintenance Program has been effective. The continued use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Protective Coating Monitoring and Maintenance Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.36 REACTOR HEAD CLOSURE STUDS

Program Description

The Reactor Head Closure Studs Program manages cracking and loss of material due to wear or corrosion for reactor head closure stud bolting (studs, washers, nuts, and flange threads) using inservice inspection (ASME Section XI, 2001 Edition, 2003 Addendum, Table IWB-2500-1) and preventive measures to mitigate the effects of aging. Preventive actions include use of an acceptable surface treatment, use of stable lubricants, use of bolting materials with low susceptibility to SCC, and avoidance of the use of metal-plated stud bolting. The program detects cracks, loss of material, and leakage using visual, surface, and volumetric examinations as required by ASME Section XI. The program also relies on recommendations to address reactor head closure bolting degradation listed in NUREG-1339 and NRC RG 1.65.

NUREG-1801 Consistency

The Reactor Head Closure Studs Program, with enhancement, will be consistent with the program described in NUREG-1801, Section XI.M3, Reactor Head Closure Stud Bolting, with one exception.

Exceptions to NUREG-1801

The Reactor Head Closure Studs Program has the following exception.

Element Affected	Exception
2. Preventive Actions	NUREG-1801 recommends use of bolting material for closure studs that has an actual measured yield strength less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch [ksi]). RBS uses bolting material for closure studs with a maximum reported ultimate tensile strength below 170 ksi.[1]

Basis for Exception

1. The criterion of actual yield strength less than 150 ksi was recommended in Section 3 of NUREG-1339 to be used as the level for consideration of vulnerability to SCC. The studs, nuts and washers at RBS are fabricated from SA 540 Grade B23 or B24 carbon steel, which has a minimum yield strength of 130 ksi. Data relative to actual yield strength for the installed reactor head closure studs is not available. However, SA 540 Grades B23 and B24 are high-strength, low-alloy materials that, when tempered to a maximum tensile strength of 170 ksi, are relatively immune to SCC. Therefore, the studs installed at RBS are relatively immune to SCC. Nevertheless, since the actual yield strength of the installed studs is not known, the aging management review conservatively identified the stud material as "high strength low alloy steel" susceptible to the aging effect of cracking. The examination methods used for stud inspection in the Reactor Head Closure Studs Program are appropriate to identify cracking. The RBS program uses reactor vessel closure stud examinations in accordance with the ASME Code Section XI Table IWB-2500-1, Examination Category B-G-1. Therefore, the 150 ksi actual yield strength preventive measure is not necessary to assure that the reactor head closure studs can perform their intended function consistent with the current licensing basis through the period of extended operation.

Enhancements

The following enhancement will be implemented prior to the period of extended operation.

Element Affected	Enhancement
7. Corrective Actions	Revise Reactor Head Closure Studs Program procedures associated with procurement requirements to ensure replacement studs are fabricated from bolting material with actual measured yield strength less than 150 ksi.

Operating Experience

The operating experience provides objective evidence that the Reactor Head Closure Studs Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis during the period of extended operation.

A review of Owners Acceptance Reports since the 2006 refueling outage identified no items in the scope of this program with flaws or relevant conditions requiring evaluation in accordance with ASME Section XI.

As discussed in element 10 to NUREG-1801, Section XI.M3, this program considers the technical information and industry operating experience provided in NRC IE Bulletin 82-02 and NRC GL 91-17.

Inspections on the reactor vessel closure studs are performed in accordance with program requirements, which include an examination of 100 percent of studs, nuts and washers each 10 years. The operating experience review identified no deficiencies noted in the past 10 years of inspection activity for this program. The continued use of proven inspection methods and preventive measures provides reasonable assurance that the Reactor Head Closure Studs Program will remain effective through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Reactor Head Closure Studs Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.37 REACTOR VESSEL SURVEILLANCE

Program Description

The Reactor Vessel Surveillance Program manages reduction of fracture toughness and long-term operating conditions for reactor vessel beltline materials as defined by 10 CFR 50 Appendix G, Section II.F using material data and dosimetry. The program ensures that the specimen exposure, capsule withdrawal, sample testing, and capsule storage meet the requirements of 10 CFR 50, Appendix H for vessel material surveillance and American Society for Testing and Materials (ASTM) E 185.

The program provides sufficient material data and dosimetry to (a) monitor irradiation embrittlement at the end of the period of extended operation and (b) establish operating restrictions on the inlet temperature, neutron spectrum, and neutron flux after a surveillance capsule is withdrawn for testing. Surveillance capsule testing and reporting, to the extent practicable, is performed in accordance with the requirements of ASTM E 185 Standard.

The Reactor Vessel Surveillance Program has been integrated into the BWRVIP Integrated Surveillance Program (ISP). The surveillance sample materials remaining in the RBS reactor pressure vessel (RPV) are maintained for possible future use. The BWRVIP ISP replaces individual plant reactor pressure vessel surveillance capsule programs with representative weld and base materials data from host reactors. Throughout the term of the ISP, the BWRVIP monitors the progress, coordinates actions such as withdrawal and testing of capsules and reporting of surveillance capsule test results, and identifies additional program needs. The BWRVIP identifies and implements changes to the program as the need arises. When specific changes are identified to the ISP testing matrix, withdrawal schedule, or testing and reporting of individual capsule results, these modifications are submitted to the NRC in a timely manner so that appropriate arrangements can be made for implementation. RBS maintains participation in the BWRVIP ISP consistent with provisions of NUREG-1801 Section XI.M31.

The integrated surveillance program for the extended period of operation (ISP(E)), based on BWRVIP document BWRVIP-86, Revision 1-A, has been approved for use by the NRC. BWRVIP-135 provides reactor pressure vessel surveillance data and other technical material information for the plants participating in the ISP and is revised periodically as additional surveillance data is obtained. RBS follows the requirements of the BWRVIP ISP and applies the ISP data. Changes to the capsule withdrawal schedule, including spare capsules, must be approved by the NRC prior to implementation, and untested capsules placed in storage are maintained for future insertion. These measures are effective in detecting the extent of embrittlement to prevent significant degradation of the reactor pressure vessel during the period of extended operation.

NUREG-1801 Consistency

The Reactor Vessel Surveillance Program is consistent with the program described in NUREG-1801, Section XI.M31, Reactor Vessel Surveillance, with one exception.

Exceptions to NUREG-1801

The Reactor Vessel Surveillance Program has the following exception.

Element Affected	Exception
4. Detection of Aging Effects	NUREG-1801 recommends that the Reactor Vessel Surveillance Program shall have at least one capsule with projected neutron fluence equal to or exceeding the 60-year reactor vessel wall neutron fluence prior to the end of the period of extended operation. The BWR integrated surveillance program (ISP) test plan does not meet this criterion for material surveillance capsules representing the RBS reactor vessel materials.[1]

Bases for Exception

1. In a letter dated July 24, 2003, RBS was issued License Amendment No. 136 approving participation in the BWRVIP Integrated Surveillance Program (ISP). In an SER (TAC No. ME2190) dated October 20, 2011, the staff approved BWRVIP-86, Revision 1, BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan. The NRC staff concluded that the ISP defined in BWRVIP-86, Revision 1, continues to adequately address the requirements of Appendix H to 10 CFR Part 50 for BWR licensees through the end of each facility's proposed 60-year operating license. BWRVIP-86, Revision 1, Section 5, includes provisions to apply the embrittlement evaluation described in RG 1.99, Revision 2, for evaluating materials and calculating an adjusted reference temperature. The use of RG 1.99, Revision 2, to project the embrittlement evaluation is also described in Element 5 of NUREG-1801 XI.M31. This exception is justified because the provisions set forth in RG 1.99, Revision 2, are acceptable for embrittlement evaluation.

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Reactor Vessel Surveillance Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2000 at approximately 10.08 EFPY, specimens from surveillance specimen capsule 183° were removed for examination in accordance with the BWRVIP Integrated Surveillance Program (ISP). The examinations are performed to determine changes in material properties, and the results are used to update Technical Specification pressure-temperature limits. The Charpy data trends obtained from examination of the surveillance specimens showed that neutron-induced embrittlement of the limiting plate and welds was consistent with the data from other industry participants in the BWRVIP ISP.

The continued participation in the BWRVIP ISP provides RBS with the benefit of reactor vessel surveillance program operating experience from all participants in the ISP. There is confidence that continued conduct of the Reactor Vessel Surveillance Program in accordance with the provisions of the ISP will effectively manage reduction of fracture toughness of reactor vessel beltline materials due to neutron irradiation embrittlement. The Reactor Vessel Surveillance Program provides reasonable assurance that the effects of aging will be managed such that the affected components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Reactor Vessel Surveillance Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.38 RG 1.127, INSPECTION OF WATER-CONTROL STRUCTURES ASSOCIATED WITH NUCLEAR POWER PLANTS

Program Description

RBS is not committed to the requirements of NRC RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." However, the program at RBS was developed based on guidance provided in NRC RG 1.127, Revision 1, and provides an inservice inspection and surveillance program for the raw water-control structures associated with standby service water cooling and service water cooling systems or flood protection. The program performs periodic visual examinations to monitor the condition of water-control structures and structural components, including structural steel and structural bolting associated with water-control structures and miscellaneous steel associated with these structures. The program addresses degradation due to the effects of aging, degradation due to extreme environmental conditions, and the effects of natural phenomena that may affect water-control structures. The program requires periodic monitoring and maintenance of water-control structures so that the consequences of degradation due to the effects of aging can be prevented or mitigated in a timely manner.

Underground concrete structures and structures in contact with ground water are not subject to an aggressive environment. The program will perform periodic sampling and chemical analysis of ground water for pH, chlorides, and sulfates on a frequency of at least once every five years to ensure that the ground water has not become aggressive.

The program contains guidance on engineering data compilation, inspection activities, technical evaluation, inspection frequency, and the content of inspection reports. Inspections of water control structures are conducted by or under the direction of qualified engineers experienced in the investigation, design, construction, and operation of the structures. Inspections are conducted systematically using checklists and other documents as required to minimize the possibility of overlooking significant features. Technical evaluations are performed if observed degradation has the potential for impacting the intended function of the water-control structures.

NUREG-1801 Consistency

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.S7, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise plant procedures to include a list of structural components and commodities within the scope of license renewal to be monitored in the program
2. Preventive Actions	Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."
3. Parameters Monitored or Inspected	Revise plant procedures to include the following parameters to be monitored or inspected: • For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • For chemical analysis of ground water, monitor pH, chlorides and sulfates. • Anchor bolts (nuts and bolts) for loss of material and loose or missing nuts and bolts.
4. Detection of Aging Effects	Revise plant procedures to include the following requirements: • Structures will be inspected on an interval not to exceed five years with provisions for more frequent inspections of structures and components categorized as (a)(1) in accordance with 10 CFR 50.65. • Inspection of submerged structures at the same inspection interval and limitations as the other structures in the program. • Sampling and chemical analysis of ground water at least once every five years. The program owner will review the results, evaluate anomalies, and trend the results.

Operating Experience

The following operating experience provide objective evidence that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2005, a periodic assessment of structures within the scope of the maintenance rule included the standby cooling tower, the service water cooling (SWC) switchgear building, SWC cooling tower and flume, SWC heat exchanger foundation, normal service water pumps foundation, and the service water surge tank. Overall condition of the structures inspected was deemed acceptable.

- In 2009, an inspection was performed for the Division I standby cooling tower. The inspected areas were below the fans, above the fans, and the area above the fill including the spray header and associated piping and hardware. The overall condition of the Division I side of the tower was very good. No structural, mechanical or otherwise functional defects that could have a negative impact on the operability of the tower were found. Some surface corrosion was observed along with other minor maintenance items, which were repaired or otherwise resolved.

- In 2013, an inspection was performed of the standby cooling towers. Inspection results were deemed acceptable. No significant concrete cracking was observed. The concrete showed no signs of deterioration. Several indications of miscellaneous steel rusting on the drift eliminator/piping concrete support beams was noted but judged to be rebar support chair steel or form ties, due to the very thin cover at these locations. There was no evidence of structural rebar exposure or deterioration. Piping and fans showed no evidence of rust or deterioration.

- In 2014, a periodic assessment of structures within the scope of the maintenance rule included the SWC cooling tower and flume, SWC heat exchanger foundation, SWC switchgear building, and the normal service water pumps foundation. Water leaks were found within the concrete construction joints of the elevated tower on the east and west side walls. The leaks drain back into the SWC basin. A work request was initiated to repair the leaks. The SWC cooling tower was judged acceptable with deficiencies. The metal siding of the SWC switchgear building was degraded with multiple rust holes in the bottom of the wall panels. A work order was initiated to repair the condition, and the building was deemed acceptable with deficiencies. The pump foundation was acceptable.

As discussed in element 10 to NUREG-1801, Section XI.S7, this program considers the technical information and industry operating experience provided in NUREG-1522.

The identification of degradation and initiation of corrective action prior to loss of intended function demonstrates that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program has been effective. The continued application of proven inspection methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.39 SELECTIVE LEACHING

Program Description

The Selective Leaching Program is a new program that will demonstrate the absence of selective leaching through assessment of a sample of components (i.e., 20 percent of the population with a maximum of 25 components) fabricated from gray cast iron and copper alloys (except for inhibited brass) that contain greater than 15 percent zinc or greater than 8 percent aluminum in an environment of raw water, treated water, or soil. A population is defined as components with the same material and environment combination. Where practical, the sample will focus on components most susceptible to the effects of aging due to time in service, severity of operating condition, and lowest design margin. The program will include a one-time visual inspection of selected components coupled with hardness measurement or other mechanical examination techniques such as destructive testing, scraping, or chipping to determine whether loss of material is occurring due to selective leaching that may affect the ability of a component to perform its intended function through the period of extended operation.

For buried components with coatings, no selective leaching inspections are necessary where coating degradation has not been identified. For buried components with degraded coating or no coatings, the sample size is 20 percent of the population up to a maximum of 25 components. If only minor coating damage has been identified, the sample size may be reduced to 5 percent of the population with a maximum of 6 components. Minor coating degradation is defined as (a) there were no more than two instances of degradation identified in the 10-year period prior to the period of extended operation, and (b) the pipe could be shown to meet the unreinforced opening criteria of the applicable piping code when assuming the pipe surface affected by the coating degradation is a through-wall hole.

Follow-up of unacceptable inspection findings will include an evaluation using the corrective action program and expansion of the inspection sample size and location.

The inspections will be performed within the five years prior to the period of extended operation.

NUREG-1801 Consistency

The Selective Leaching Program will be consistent with the program described in NUREG-1801, Section XI.M33, Selective Leaching, as modified by LR-ISG-2011-03, "Changes to the Generic Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks,'" and LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Selective Leaching Program is a new program. Industry operating experience will be considered during implementation of this program. As stated in NUREG-1801, Revision 2, Section XI.M33, the inspection elements of this program (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice.

This inspection program applies to potential aging effects for which there is no operating experience at RBS indicating the need for an aging management program. The review of operating experience at RBS did not identify an occurrence of selective leaching.

The Selective Leaching Program will be consistent with the program description in NUREG-1801, which in turn is based on industry operating experience that demonstrates that this program is effective for managing the aging effects requiring management. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Selective Leaching Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation. The program provides reasonable assurance of the absence or insignificance of certain aging effects that are not expected to be significant during the period of extended operation.

B.1.40 SERVICE WATER INTEGRITY

Program Description

The Service Water Integrity Program manages loss of material and reduction of heat transfer for service water system components fabricated from carbon steel, carbon steel with copper cladding, stainless steel, and copper alloy in an environment of treated water.

The program includes periodic (a) testing of the RHR heat exchangers to verify heat transfer capability, (b) inspection and maintenance of the auxiliary building unit coolers, (c) routine maintenance (cleaning) of the RHR heat exchanger radiation monitor coolers, and (d) routine maintenance (cleaning) of the penetration valve leakage control system (PVLCS) compressor aftercoolers. There are no internal coatings in components crediting the Service Water Integrity Program for managing the effects of aging.

NUREG-1801 Consistency

The Service Water Integrity Program is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation."

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Service Water Integrity Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

The Service Water Integrity Program addresses the aging effects of loss of material and reduction of heat transfer of heat exchanger components as described in the RBS final response to NRC GL 89-13. The following are examples of how operating experience is used to improve program effectiveness.

- In 2009, a QA audit of engineering programs included the Service Water Integrity Program. The results were satisfactory based on interviews, a review of records, and field observation.

- One heat exchanger and seven unit coolers were inspected during Cycle 16 and its refueling outage, a period from October 18, 2009, to February 12, 2011. Visual inspections were performed for the heat exchanger and five unit coolers. Results were satisfactory with no indications of active corrosion, blockage, or tube fouling. For four unit coolers, UT inspections performed to address potential flow erosion concerns were completed with acceptable results.
- In 2011, the NRC identified a green non-cited violation for failure to establish a GL 89-13 test program that incorporates a final test frequency for the RHR heat exchangers and performs an adequate trending analysis upon which to base a final test frequency. A site response to GL 89-13 included testing the RHR heat exchangers due to shell-side concerns with untreated suppression pool water, with the frequency to be evaluated after three tests. Since issuance of this letter, the heat exchangers in each RHR division had been tested six times, with generally improving results. The corrective action taken to address this violation included revising the preventive maintenance frequency for RHR heat exchanger thermal performance testing to once every four years with the due dates for the next test to be during first quarter 2012 for the Division II heat exchanger and first quarter 2014 for the Division I heat exchanger.
- In 2012, the Division II RHR heat exchanger's heat transfer capacity was verified by testing. This evaluation determined that the heat exchangers are capable of removing the required heat load at design limiting conditions.
- In 2015, service water cooling (SWC) system pH was found below the best practice limit. The event occurred when the SWC pH controllers lost power and defaulted to an automatic mode when power was restored, increasing the pump stroke. A chemistry technician recognized this condition and secured acid addition to the SWC system. SWC pH recovered to within best practice limits.

As discussed in element 10 to NUREG-1801, Section XI.M20, this program considers the technical information and industry operating experience provided in NRC IN 85-30, IN 07-06, IN 85-24, IN 81-21, IN 86-96, IN 07-04, IN 07-28 and NRC GL 89-13.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the Service Water Integrity Program has been effective. The continued application of proven monitoring methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Service Water Integrity Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.41 STRUCTURES MONITORING

Program Description

The Structures Monitoring Program manages the effects of aging on structures and structural components, including structural bolting, within the scope of license renewal. The program was developed based on guidance in RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, Revision 2, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to satisfy the requirement of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The scope of the Structures Monitoring Program includes structures within the scope of license renewal as delineated in 10 CFR 54.4.

The structures and structural components are inspected by qualified personnel. Concrete structures are inspected for indications of deterioration and distress, using guidelines provided in ACI 201.1R, "Guide for Making a Condition Survey of Existing Buildings," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures." Elastomers will be monitored for hardening, shrinkage and loss of sealing. Component supports will be inspected for loss of material and reduction in anchor capacity due to local concrete degradation. Exposed surfaces of bolting are monitored for loss of material, loose or missing nuts, missing bolts, or other indications of loss of preload. Implementing plant procedures ensure that the selection of bolting material, installation torque or tension, and lubricants and sealants are appropriate for the intended purpose. The program includes preventive actions delineated in NUREG-1339 and in EPRI NP-5769, NP-5067, and TR-104213 to ensure structural bolting integrity, which includes proper specification of bolting material, lubricant, and installation torque.

Inspections are performed at a frequency of at least once every five years to ensure there is no loss of intended function. The program contains provisions for increased inspection frequency and trending of structures and components in accordance with 10 CFR 50.65(a)(1), if the extent of degradation is such that the structure or component may not meet its design basis or, if allowed to continue uncorrected until the next normally scheduled assessment, may not meet its design basis.

Underground concrete structures and structures in contact with ground water are not subject to an aggressive environment. The program will perform periodic sampling and chemical analysis of ground water for pH, chlorides, and sulfates on a frequency of at least once every five years to ensure that the ground water has not become aggressive.

For surfaces provided with protective coatings, observation of the condition of the paint or coating is an effective method for confirming the absence of degradation of the underlying material. Therefore, monitoring of the condition of coatings on SSCs within the scope of the Structures Monitoring Program is implicitly included within the program.

NUREG-1801 Consistency

The Structures Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.S6, Structures Monitoring Program.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	Revise plant procedures to add the following structures to the program: • Auxiliary control building • Circulating water switchgear house No. 1 • Condensate storage tank foundation • Electrical tunnels and piping tunnels • Fire protection storage tanks foundation • Fuel oil storage tank foundation • Manholes, handholes and duct banks • Transformer and switchyard support structures and foundations Revise plant procedures to include a list of structural components and commodities within the scope of the program. Revise plant procedures to include periodic sampling and chemical analysis of ground water.
2. Preventive Actions	Revise plant procedures to include the preventive actions for storage of ASTM A325, ASTM F1852, and ASTM A490 bolting from Section 2 of Research Council on Structural Connections publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

Element Affected	Enhancement
3. Parameters Monitored or Inspected	Revise plant procedures to include the following parameters to be monitored or inspected: • For concrete structures and components, include loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • For chemical analysis of ground water, monitor pH, chlorides and sulfates. Revise plant procedures to include the following components to be monitored for the associated parameters: • Anchor bolts (nuts and bolts) for loss of material and loose or missing nuts and bolts. • Elastomeric vibration isolators and structural sealants for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening).
4. Detection of Aging Effects	Revise plant procedures to include the following: • Visual inspection of elastomeric material should be supplemented by feel or touch to detect hardening if the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least 10 percent of available surface area. • Inspection of submerged structures at the same inspection interval and limitations as the other structures in the program. • Sampling and chemical analysis of ground water at least once every five years. The program owner will review the results and evaluate any anomalies and perform trending of the results.

Operating Experience

The following discussion provides objective evidence that the Structures Monitoring Program will be effective in ensuring that intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- The 2005 Maintenance Rule Structures Periodic Assessment Report documented the results of the Structures Monitoring Program first 10-year inspection of plant buildings. The plant structures and equipment inspected under the Structures Monitoring Program were in good shape. Overall condition of the structures inspected was deemed acceptable.

- In 2011, personnel found a small leak from the ceiling near where the auxiliary building connects to containment. The leakage was much less than the amount of leakage that would challenge the standby gas treatment system or the secondary containment boundary. The condition was entered into the corrective action program and repaired through the normal work management process.

- In 2012, during an engineering audit, a review of maintenance rule structures inspections found no documentation for high risk significant structures meeting the once per five-year inspection criteria. Auditors found evidence of completed inspections for some, but not all, of the applicable structures. Actions taken included revision of the site procedure to align with fleet procedure provisions, creation of a preventive maintenance model work order to formalize the structure inspection process, and verification that dates for future inspections were appropriate. Structure inspections requiring a refueling outage were added to the 2013 outage schedule and performed at that time. The plant structures and equipment inspected were all acceptable.

- During inspection of a service water cooling fan in 2012, concrete spalling was found on areas of the south wall of the service water cooling tower fan cell. The areas of spalling did not adversely impact the structural integrity of the tower. This condition was entered into the normal work management process.

- In 2013, through-wall leakage was found at some penetrations in the north wall of the Ftunnel. Corrective action had previously been initiated but not yet worked. These penetrations are required to be sealed for flood protection. The leakage was evaluated as well within the capability of the sump and pumps to control as stated in the USAR. Thus there was no adverse impact to equipment in the area. The condition was entered into the normal work management process.

- In 2013, the service water cooling tower was found leaking from the concrete grout on both the east and west side walls. The leaks were draining back into the SWC basin due to the updraft. The condition was entered into the normal work management process.

- An engineering report in 2014 documented the maintenance rule structures inspections conducted in that year. This report also documented the review of inspection assessments as well as the condition reports that had been issued against structures since 2005. Plant structures and equipment inspected were deemed in relatively good shape. Safety-related, seismic Category I buildings were in very good condition with only minor signs of degradation. General corrosion was noted for most uncoated metal surfaces in the Category I tunnels, which are underground. Where structures were deemed "acceptable with deficiencies," condition reports or work requests were initiated. The following conditions are examples of those noted during the inspections:

- During the inspection of the control building Division II, general corrosion was identified on supplementary steel supports for small bore piping in an HVAC equipment room. Engineering determined that coating of structural steel above this elevation was optional, and these deficiencies did not compromise the structural integrity of the supports. This condition was entered into the normal work management process.

- During the inspection of the CWS pump structure, the grouting on two supports on the south crane rail were found degraded. The groutwork surrounding the baseplates of two columns had broken off in sections, exposing the side face of the baseplate and the grouting underneath the plate. The grout on the sides of the baseplate is not credited for structural support. The grouting underneath the baseplate is intact. The underlying grouting is maintaining a full bearing surface and performing its design function. This condition was entered into the normal work management process.

As discussed in element 10 to NUREG-1801, Section XI.S6, this program considers the technical information and industry operating experience provided in NUREG-1522.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the Structures Monitoring Program has been effective. The use of proven program activities provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

<u>Conclusion</u>

The Structures Monitoring Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.42 WATER CHEMISTRY CONTROL – BWR

Program Description

The Water Chemistry Control – BWR Program manages loss of material, cracking, change in material properties, and reduction of heat transfer in components in an environment of treated water through periodic monitoring and control of water chemistry. The Water Chemistry Control – BWR Program monitors and controls chemical species and water quality to keep levels of various contaminants below system-specific limits. BWRVIP-190, BWR Water Chemistry Guidelines, Revision 1, is used to provide guidance for the program.

The One-Time Inspection Program (Section B.1.32) uses inspections or non-destructive evaluations of representative samples to verify that the Water Chemistry Control – BWR Program has been effective at managing aging effects. The representative sample includes low flow and stagnant areas.

NUREG-1801 Consistency

The Water Chemistry Control – BWR Program is consistent with the program described in NUREG-1801, Section XI.M2, Water Chemistry.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The following operating experience provides objective evidence that the Water Chemistry Control – BWR Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis during the period of continued operation.

- In 2006, a condition report was initiated to document the degraded condition of the hydrogen water chemistry (HWC) control panel. The condition was addressed using normal work processes.
- In 2011, a quality assurance audit included the water chemistry control programs. A two-month period of steady-state operation and a one-month period including a refueling outage were evaluated. The evaluation verified the effectiveness of chemistry controls against industry standards and plant specification by review of reactor coolant system chemistry and radiochemistry data for the selected periods to ensure parameters were maintained within specifications and contaminant ingress was controlled to meet

requirements. System chemistry specifications were maintained at steady levels, and controls were in place to prevent or manage the ingress of contaminants. The audit also included a review of conduct of chemistry with satisfactory results based on field observations and interviews. Chemistry personnel used appropriate human error prevention, radiological protection, and industrial safety techniques while conducting plant activities. A review of self-assessments and benchmarking was satisfactory.

- In 2013, a quality assurance audit included the water chemistry control programs. The area of "System Chemistry Controls and Performance" was evaluated as satisfactory. Key primary and auxiliary system chemistry parameters were maintained within specified bands, and controls were in place to prevent or manage the ingress of contaminants.

- In 2013, a condition report was initiated documenting that RCS conductivity was above the "best practice" guidelines. The EPRI level limit was not exceeded. Feedwater zinc injection was lowered, and RCS conductivity was back within best practice guidelines on the same day.

- In 2015, while the suppression pool cleanup system was being placed in service, an alarm for high conductivity was received. Chemistry reported that a sample showed high silica, which indicates that resin is exhausted. The demineralizer was removed from service, and a flush and refill was scheduled.

- Revision 10 of a strategic chemistry plan was effective in 2015. The plan was developed based upon industry experience and guidelines, the BWR cycle design, and metallurgy principles. The plan optimizes corrosion control for the reactor vessel and primary system components and the balance of plant (BOP) components, thereby minimizing primary system IGSCC, BOP system flow-accelerated corrosion, chemistry impact on fuel integrity, and radiation field buildup.

As discussed in element 10 to NUREG-1801, Section XI.M2, this program considers the technical information and industry operating experience provided in Bulletin 80-13, IN 95-17, GL 94-03, and NUREG-1544.

The identification of degradation and initiation of corrective action prior to loss of intended function, along with identification of program deficiencies and subsequent corrective actions, demonstrates that the Water Chemistry Control – BWR Program has been effective. The application of these proven methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Water Chemistry Control – BWR Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.43 WATER CHEMISTRY CONTROL – CLOSED TREATED WATER SYSTEMS

Program Description

The Water Chemistry Control – Closed Treated Water Systems Program manages loss of material, cracking, and reduction of heat transfer in components in a closed treated water environment through monitoring and control of water chemistry, including the use of corrosion inhibitors, chemical testing, and visual inspections of internal surfaces. The EPRI Closed Cooling Water Guideline (1007820), industry and site operating experience, and vendor recommendations are used to delineate the program.

NUREG-1801 Consistency

The Water Chemistry Control – Closed Treated Water Systems Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M21A, Closed Treated Water Systems, as modified by LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation."

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
4. Detection of Aging Effects	Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to inspect accessible components whenever a closed treated water system boundary is opened. Ensure that a representative sample of piping and components is inspected at a frequency of at least once every 10 years. These inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection guidance by qualified personnel using procedures that are capable of detecting loss of material, reduction of heat transfer, or cracking. If visual examination identifies adverse conditions, then additional examinations, including ultrasonic testing, are conducted. Components inspected will be those with the highest likelihood of corrosion, reduction of heat transfer due to fouling, or cracking. A representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. Components inspected will be those with the highest likelihood of loss of material, reduction of heat transfer, or cracking.

Element Affected	Enhancement
6. Acceptance Criteria	Revise the Water Chemistry Control – Closed Treated Water Systems Program procedures to provide acceptance criteria for inspections of accessible components. Ensure components meet system design requirements, such as minimum wall thickness.

Operating Experience

The following operating experience provides objective evidence that the Water Chemistry Control – Closed Treated Water Systems Program will be effective in ensuring that component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

- In 2011, a quality assurance audit included the water chemistry control programs. A two-month period of steady-state operation and a one-month period including a refueling outage were evaluated. The audit found that chemistry strategies, operating practices, and evaluation techniques, such as hideout return and impurity mass balance studies, are routinely reviewed for effectiveness and are integrated into other station performance monitoring and corrosion control initiatives. Service water is treated and controlled in accordance with industry guidelines. Performance of this system is trended and used as a basis for improvements in the chemical treatment program. The audit also reviewed conduct of chemistry with satisfactory results based on field observations and interviews. Chemistry personnel used appropriate human error prevention, radiological protection, and industrial safety techniques while conducting plant activities. A review of self-assessments and benchmarking was satisfactory. The audit identified a condition where service water nitrate concentration had not been tested once per month as specified by procedure. This was resolved by a procedure revision that removed the requirement to sample for nitrates.

- Revision 5 of the RBS closed cooling water (CCW) systems strategic plan became effective in 2013. This strategic plan describes the specific function of each CCW system and system chemistry control and monitoring to minimize corrosion and fouling and the strategic actions to accomplish this. The system chemistry control and monitoring is consistent with EPRI Closed Cooling Water Guidelines Revision 1 (2004). Where plant-specific deviations from the guidelines exist, justifications for the deviations are provided, as permitted by the guidelines. The action levels (C1 & C2) used to control the system chemistry parameters based on the EPRI Closed Cooling Water Guidelines are explained in an appendix. Corrosion coupon program information for the CCW systems is provided. The chemistry staff administers system-appropriate water chemistry management to minimize corrosion and fouling in the CCW systems.

- In 2013, a quality assurance audit included the water chemistry control programs. The area of "System Chemistry Controls and Performance" was evaluated as satisfactory.

Key primary and auxiliary system chemistry parameters were maintained within specified bands, and controls were in place to prevent or manage the ingress of contaminants. A review of self-assessments and benchmarking was satisfactory.

- In 2013, an out-of-specification sample was obtained from the control building chilled water system. The chemical impurity ingress was coincident with high water level observed in the surge tank. The source of ingress appeared to be service water, based on anion analysis, sodium analysis, and conductivity measurements. While potential flow paths for service water ingress are known, there was insufficient information to conclude a specific mechanism for ingress. There was no recurrence of the conditions indicating ingress of service water.

- In 2014, analysis of a control building chilled water sample found chemistry readings exceeding the procedural action levels. The cause was linked to swapping chillers and pumps to support maintenance. A "feed-and-bleed" of the system restored the parameters to within "best practice" values.

- In 2015, a review of the chemistry department database noted that the department was not monitoring corrosion rates via corrosion coupons in accordance with the procedure, resulting in corrosion rates not being fully characterized for the affected systems. Previous attempts to resolve the problem had been impacted by equipment issues. Corrosion coupons were installed for the service water and circulating water systems with the information documented in the coupon data tracking database. Repairs to the service water rack completed the actions required for these systems. Coupons for the closed cooling water systems for the reactor plant and the turbine plant were installed with the information documented in the coupon data tracking database. Repairs to the turbine plant closed cooling water coupon rack were addressed using normal work processes.

As discussed in element 10 to NUREG-1801, Section XI.M21A, this program considers the technical information and industry operating experience provided in NRC LER 50-327/93-029-00 and LER 50-280/91-019-00.

The identification of out-of-specification chemistry parameters and initiation of corrective action, along with identification of program deficiencies and subsequent corrective actions, demonstrate that the Water Chemistry Control – Closed Treated Water Systems Program has been effective. The continued application of these proven methods provides reasonable assurance that the effects of aging will be managed such that components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4.

Conclusion

The Water Chemistry Control – Closed Treated Water Systems Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.2 REFERENCES

B.2-1 NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*, Revision 2, U.S. NRC, December 2010.

B.2-2 NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, Revision 2, U.S. NRC, December 2010.

Appendix C

Response to BWRVIP Applicant Action Items

River Bend Station
License Renewal Application

Of the BWRVIP documents credited for RBS license renewal, the following have NRC safety evaluation reports (SERs) that include license renewal applicant action items:

BWRVIP-18	BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines, Revision 1-A
BWRVIP-25	BWR Core Plate Inspection and Flaw Evaluation Guidelines, Revision 1
BWRVIP-26-A	BWR Top Guide Inspection and Flaw Evaluation Guidelines
BWRVIP-27-A	BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines
BWRVIP-38	BWR Shroud Support Inspection and Flaw Evaluation Guidelines
BWRVIP-41	BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines, Revision 3
BWRVIP-42	BWR Low Pressure Coolant Injection (LPCI) Coupling Inspection and Flaw Evaluation Guidelines, Revision 1
BWRVIP-47-A	BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
BWRVIP-48-A	Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines
BWRVIP-49-A	Instrument Penetration Inspection and Flaw Evaluation Guidelines
BWRVIP-74-A	BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines
BWRVIP-76	BWR Core Shroud Inspection and Flaw Evaluation Guidelines, Revision 1-A

License renewal applicant action items identified in the corresponding SER for each of the above reports are addressed in the following table. BWRVIP documents without SERs for license renewal have no applicant action items and are therefore not included in the table.

The SERs contain three common applicant action items, which are addressed only once in the table. For SERs that contain additional applicant action items, the response is provided separately following the responses to the three common action items.

Action Item Description	Response
Common Action Items from BWRVIP-18, Rev. 1-A; -25, Rev. 1; -26-A; -27-A; -38; -41, Rev. 3; -42, Rev. 1; -47-A; -48-A; -49-A; -74-A; -76, Rev. 1-A	
BWRVIP-All (1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWRVIP reports have been reviewed and RBS has been verified to be bounded by the reports. Additionally, RBS commits to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50, Appendix B. Deviation from a BWRVIP report approved by the NRC will be reported to the NRC.
BWRVIP-All (2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.	The USAR supplement is provided as Appendix A of the LRA and includes a summary of the programs and activities specified as necessary for the BWRVIP program.

Action Item Description	Response
Common Action Items from BWRVIP-18, Rev. 1-A; -25, Rev. 1; -26-A; -27-A; -38; -41, Rev. 3; -42, Rev. 1; -47-A; -48-A; -49-A; -74-A; -76, Rev. 1-A	
BWRVIP-All (3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications associated with the report as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the inspection strategy described in the reports does not conflict with or result in any changes to their technical specifications. If technical specification changes or additions do result, then the applicant must ensure that those changes are included in its application for license renewal.	No technical specification changes have been identified for RBS based upon the BWRVIP reports.
Additional Action Items	
BWRVIP-18, Rev. 1-A, Core Spray Internals Inspection and Flaw Evaluation Guidelines	
BWRVIP-18-A, Rev. 1-A (4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components.	TLAA identified for core spray internals have been evaluated for RBS. The BWR Vessel Internals Program (Section B.1.10) will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).

Action Item Description	Response
BWRVIP-25, Rev. 1, Core Plate Inspection and Flaw Evaluation Guidelines	
BWRVIP-25, Rev. 1 (4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	BWRVIP-25 concluded that preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants that have not installed core plate wedges. Since RBS is a BWR/6 with core plate wedges, the preload on the core plate bolts is not required. Therefore, there is no associated TLAA for RBS.
BWRVIP-25, Rev. 1 (5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	Under the guidance and recommendations of BWRVIP-25, no core plate or rim hold-down inspections are recommended for BWR/6 reactors such as RBS.
BWRVIP-26-A, Top Guide Inspection and Flaw Evaluation Guidelines	
BWRVIP-26-A (4) Due to IASCC [irradiation-assisted stress corrosion cracking] susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.	Accumulated neutron fluence projected to 60 years for RBS exceeds the threshold for IASCC susceptibility for the top guide. However, BWRVIP-26-A does not constitute a TLAA for RBS since it was not used to make any safety determination or as justification for reducing the number of inspections. Since RBS has implemented the inspection requirements of BWRVIP-26-A and BWRVIP-183, the BWR Vessel Internals Program (Section B.1.10) will adequately manage the effects of aging on the top guide for the period of extended operation.

Action Item Description	Response
BWRVIP-27-A, Standby Liquid Control System /Core Plate ΔP Internals Inspection and Flaw Evaluation Guidelines	
BWRVIP-27-A (4) Due to the susceptibility of the subject components to fatigue, applicants referencing the BWRVIP-27 report for license renewal should identify and evaluate the projected fatigue cumulative usage factors as a potential TLAA issue.	The ΔP/SLC lines inside the reactor vessel have no safety or license renewal intended function and are not subject to aging management review. Refer to LRA Section 2.3.1.1.2 for further discussion of the ΔP/SLC lines and Section 4.3.1.2 for further discussion of fatigue and CUFs for the reactor vessel internals for the period of extended operation.
BWRVIP-42, Rev. 1, LPCI Coupling Inspection and Flaw Evaluation Guidelines	
BWRVIP-42, Rev. 1 (4) Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components	The potential TLAAs for LPCI components have been evaluated for RBS. BWRVIP-42, Rev. 1, identifies a methodology for growth analysis for any observed flaw, but no flaw has been identified in the LPCI coupling at RBS. The BWR Vessel Internals Program (Section B.1.10) will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).
BWRVIP-42, Rev. 1 (5) The BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR [license renewal] applicant notify the NRC of actions planned. Applicants referencing the BWRVIP-42 report for license renewal should identify this action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff.	The BWRVIP has developed strategies to ensure the integrity of inaccessible welds. These strategies are included in Section 3 of BWRVIP-42, Revision 1. RBS has committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operation. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50, Appendix B.

Action Item Description	Response
BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
BWRVIP-47-A (4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	TLAAs identified for lower plenum components have been evaluated for RBS. RBS has a fatigue evaluation (calculated CUF) for selected lower plenum components. The BWR Vessel Internals Program (Section B.1.10) will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).
BWRVIP-74-A, BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
BWRVIP-74-A (4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD [vessel flange leak detection] lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The VFLD line is within the scope of license renewal and subject to aging management review. Loss of material and cracking are identified as aging effects requiring management. The Water Chemistry Control – BWR Program (Section B.1.42), in conjunction with the One-Time Inspection Program (Section B.1.32), manages the effects of aging on the VFLD line.
BWRVIP-74-A (5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventive actions, (3) parameters monitored and inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	The description of the only plant-specific aging management program in LRA Appendix B, in Section B.1.34, addresses the required ten elements.

Action Item Description	Response
BWRVIP-74-A (6) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applicants shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29.	The Water Chemistry Control – BWR Program (Section B.1.42) monitors and controls reactor water chemistry in accordance with the guidelines of BWRVIP-190, which supersedes BWRVIP-29.
BWRVIP-74-A (7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific-invessel surveillance program, applicable to the LR term.	RBS has received NRC approval to use the BWRVIP ISP. This has been applied to the Reactor Vessel Surveillance Program (Section B.1.37).
BWRVIP-74-A (8) LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.	Fatigue during the period of extended operation (including thermal cycles, projected cumulative usage factors, environmental fatigue) has been evaluated for RBS. See the Fatigue Monitoring Program (Section B.1.18).
BWRVIP-74-A (9) Appendix A to the BWRVIP-74 report indicates that a set of P-T curves should be developed for the heat-up and cool-down operating conditions in the plant at a given EFPY in the LR period.	Analysis to determine pressure-temperature limits for the period of extended operation has been evaluated as a TLAA in Section 4.2.3. Pressure-temperature limit curves will continue to be updated, as required by Appendix G of 10 CFR Part 50.

Action Item Description	Response
BWRVIP-74-A (10) To demonstrate that the beltline materials meet the Charpy USE criteria specified in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.	Evaluation of percent reduction in Charpy upper shelf energy (USE) for beltline materials, plates, and welds for the period of extended operation has been performed. The reductions have been shown to remain less than the limiting reductions discussed in BWRVIP-74-A. For the extended operating term, RBS beltline materials were evaluated using RG 1.99, Revision 2. The calculations were based upon the peak ¼T fluence for 54 EFPY. The results of this evaluation demonstrate that all beltline materials remain above 50 ft-lb. The TLAA for USE has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).
BWRVIP-74-A (11) To obtain relief from the in-service inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E for the staff's July 28, 1998, FSER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	RBS has received relief from the in-service inspection of the circumferential welds for the remaining term of the original operating license. Circumferential weld inspection relief, if necessary for the period of extended operation, will be requested through a reapplication under the 10 CFR 50.55a process. Therefore, this is categorized in accordance with 10 CFR 54.21(c)(1)(iii). See Section 4.2.5.

Action Item Description	Response
BWRVIP-74-A (12) As indicated in the staff's March 7, 2000, letter to Carl Terry, an LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of this FSER.	The limiting axial beltline weld has been evaluated using the fluence at the end of the period of extended operation and the limiting material properties (chemistry and initial RT_{NDT}) of the applicable adjoining materials. This evaluation has been projected through the period of extended operation per 10 CFR 54.21 (c)(1)(ii). See Section 4.2.4.
BWRVIP-74-A (13) The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using staff-approved methodology or may submit the methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.	The method used for the neutron fluence calculation adheres to the guidance prescribed in RG 1.190. The TLAA for neutron fluence in the RPV beltline has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii) as discussed in Section 4.2.1.
BWRVIP-74-A (14) Components that have indications that have been previously analytically evaluated in accordance with subsection IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be reevaluated for the 60-year service period corresponding to the LR term.	No ASME Section XI flawed component evaluations performed in accordance with subsection IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period were identified for RBS.

Action Item Description	Response
BWRVIP-76, Rev. 1-A, BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
BWRVIP-76, Rev. 1-A (4) The applicants shall reference the NRC staff approved TRs BWRVIP-14-A, BWRVIP-99 (when approved) and BWRVIP-100-A in their RVI components' AMP. The applicants shall make a statement in their LRAs that the crack growth rate evaluations and fracture toughness values specified in these reports shall be used for cracked core shroud welds that are exposed to the neutron fluence values that are specified in these TRs. The applicants shall confirm that they will incorporate any emerging inspection guidelines developed by the BWRVIP for these welds.	The RBS BWR Vessel Internals Program (Section B.1.10) references BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100, Revision 1. The crack growth rate evaluations and fracture toughness values specified in these reports are used for cracked core shroud welds that are exposed to the neutron fluence values specified in these BWRVIP reports. Any emerging inspection guidelines developed by the BWRVIP for these welds are incorporated into this program.
BWRVIP-76, Rev. 1-A (5) LR applicants that have core shrouds with tie rod repairs shall make a statement in their AMPs associated with the RVI components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on their units and incorporated revised inspection guidelines, if any, developed by the BWRVIP.	RBS does not have a core shroud with tie rod repairs.

Action Item Description	Response
BWRVIP-76, Rev. 1-A (6) The NRC staff's guidance in Table IV.B1 of the GALL Report lists two potentially applicable aging effects (i.e., in addition to cracking) for generic BWR reactor vessel internal components (including BWR core shroud and core shroud repair assembly components) that are made from either stainless steel (including CASS) or nickel alloy: (1) loss of material due to pitting and crevice corrosion (Refer to GALL AMR IV.B1-15), and (2) cumulative fatigue damage (Refer to GALL AMR item IV.B1-14). BWR LR applicants will need to assess their designs to see if the generic guidelines for managing cumulative fatigue damage in GALL AMR item IV.B1-14 and for management loss of material due to pitting and crevice corrosion in GALL AMR IV.B1-15 are applicable to the design of their core shroud components (including welds) and any core shroud repair assembly components that have been installed through a design modification of the plant. If these aging effects are applicable to the design of these components as a result of exposing them to a reactor coolant with integrated neutron flux environment, applicants for license renewal will need to: (1) identify the aging effects as aging effects requiring management (AERM) for the core shrouds and for their core shroud repair assembly components if a repair design modification has been implemented, and (2) identify the specific aging management programs or time-limited aging analyses that will be used to manage these aging effects during the period of extended operation. Refer to License Renewal Applicant Action Item 7) for additional guidance on identifying the AERMs for core shroud components or core shroud repair assembly components that made from materials other than stainless steel (including CASS) or nickel alloy.	The RBS core shroud is fabricated from stainless steel. The aging effects requiring management of loss of material and cracking have been assigned to the core shroud. The BWR Vessel Internals Program (Section B.1.10) and Water Chemistry Control – BWR Program (Section B.1.42) have been credited to manage loss of material due to pitting and crevice corrosion and cracking. Flaw evaluation and calculation methodology for the core shroud and associated welds are provided in BWRVIP-76. The methods consider limit load, linear elastic fracture mechanics, elastic-plastic fracture mechanics, and statistical approaches. RBS addresses fatigue of the reactor vessel internals for the period of extended operation in Section 4.3.1.2. The BWR Vessel Internals Program (Section B.1.10) will manage the effects of aging due to fatigue on the reactor vessel internals in accordance with 10 CFR 54.21(c)(1)(iii).

Action Item Description	Response
BWRVIP-76, Rev. 1-A (7) For BWR LRAs identification of AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy will need to be addressed on a plant specific basis that is consistent with the Note format criteria for plant-specific AMR items in latest NRC-approved version TR NEI-95-10.	This item is not applicable. The RBS core shroud is fabricated from Type 304L stainless steel, and no repair hardware has been installed.
BWRVIP-76, Rev. 1-A (8) LR applicants shall reference the NRC staff-approved topical reports BWRVIP-99 and BWRVIP-100-A in their RVI components' AMP, as discussed in section 3.3 of this SER.	BWRVIP-99-A and BWRVIP-100, Rev. 1, are referenced in the BWR Vessel Internals Program (Section B.1.10).

Appendix D

Technical Specification Changes

River Bend Station License Renewal Application

10 CFR 54.22 requires that an application for license renewal include any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation. A review of the information in this License Renewal Application and the RBS Technical Specifications determined that no changes to the Technical Specifications are required.