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SECTION 18

18.0 MANAGING THE EFFECTS OF COMPONENT AGING

18.0.1 Introduction

This section provides a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses in accordance with 10 CFR 54.21(d). These programs and activities were developed to support renewal of the original operating license for Davis-Besse Nuclear Power Station Unit No. 1 (DBNPS) that was scheduled to expire on April 22, 2017.

An integrated plant assessment in support of license renewal identified the aging management programs (AMPs) and activities necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions for the period of extended operation. The period of extended operation (PEO) is the 20-year period ending April 22, 2037.

For each of the plant-specific time-limited aging analyses, the evaluations have determined that the analyses remain valid for the period of extended operation; the analyses have been projected to the end of the period of extended operation; or, that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The license renewal integrated plant assessment and evaluation of time-limited aging analyses (TLAAs) identified existing and new aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis during the PEO. The aging management programs identified as necessary in association with the evaluation of time-limited aging analyses are described in Sections 18.1.14 and 18.1.16.

Appendix A of NUREG-2193, *Safety Evaluation Report Related to the License Renewal of Davis-Besse Nuclear Power Station*, (April 2016) and Supplement 1 to NUREG-2193 (April 2016), identified commitments associated with the aging management programs and activities to manage aging effects for structures and components. These commitments are provided in Table 18-1, "License Renewal Commitments."

18.0.2 Operating Experience

Operating experience from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience program, which meets the requirements of NUREG-0737, *Clarification of TMI Action Plan Requirements*, Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The operating experience program interfaces with and relies on active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC. The Operating Experience Program processes and procedures for the ongoing review of operating experience include the following attributes:

- Training on age-related degradation and aging management is provided to those personnel responsible for implementing aging management programs and who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience to ensure they are qualified for the task. This training is to occur

on the frequency determined by training procedures and processes, and includes provisions to accommodate the turnover of plant personnel.

- While the programs and procedures may specify reviews of certain sources of information, such as NRC generic communications, revisions to NUREG-1801, *Generic Aging Lessons Learned (GALL) Report*, and Institute of Nuclear Power Operations reports, they allow for any potential source of relevant plant-specific or industry operating experience information.
- The processes are adequate so as to not preclude the consideration of operating experience related to aging management. The processes allow for appropriately gathering information on structures and passive components within the scope of license renewal, their materials, environments, aging effects, and aging mechanisms, and the aging management programs credited for managing the effects of aging, including the activities under these programs (e.g., inspection methods, preventive actions or evaluation techniques).
- Plant-specific operating experience, including aging-related operating experience, is documented in condition reports and processed using the Corrective Action Program. The Corrective Action Program database includes an "Aging" flag to identify plant-specific operating experience concerning age-related degradation to structures and components within the scope of license renewal and managed by a license renewal aging management program. Condition reports for adverse conditions and related documents captured in the Corrective Action Program database are quality records and are auditable and retrievable.
- Industry operating experience, including aging-related operating experience, is entered into the Operating Experience Program database and screened for applicability to Energy Harbor Nuclear Corp. The Operating Experience Program database includes an "Aging" flag to identify plant-specific and industry operating experience concerning age-related degradation to structures and components within the scope of license renewal and managed by a license renewal aging management program. Documents captured in the Operating Experience Program database are retrievable.
- Evaluations of internal and external aging-related operating experience issues associated with structures and passive components include consideration of the affected structure or component, material, environment, aging effect, aging mechanism, and aging management program, with feedback to the affected aging management program owner for consideration of the impact to aging management program effectiveness.
- Aging management program owners review data collected by program activities, use the Corrective Action Program to document adverse conditions to ensure they will be addressed and corrected, maintain required records for the program, maintain the program current, and implement revisions as needed based on program results and internal or external operating experience evaluations. Revision of existing or development of new aging management programs based on operating experience evaluations is performed through corrective actions using the Corrective Action Program, or by action items identified in the Operating Experience Program database.

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- Noteworthy plant-specific aging-related operating experience is shared with the other Energy Harbor Nuclear Corp. sites and the industry. The Operating Experience Program procedure provides guidance on sharing internal operating experience, using evaluation criteria for events or issues related to aging management such as:
 - Discovery of a previously unknown or unexpected aging effect or aging mechanism for the applicable material and environment combination; or,
 - Recommendation for a significant change in an aging management program (e.g., a significant change to monitoring or inspection frequency or technique, or to preventive actions).

18.1 SUMMARY DESCRIPTIONS OF AGING MANAGEMENT PROGRAMS (AMPs) AND ACTIVITIES

18.1.1 10 CFR Part 50, Appendix J Program

The 10 CFR Part 50, Appendix J Program monitors Containment leak rate. Containment leak rate tests are required to assure that: (a) leakage through primary Containment, and systems and components penetrating primary Containment, shall not exceed allowable values specified in the Technical Specifications, and (b) periodic surveillance of primary Containment penetrations and isolation valves is performed so that proper maintenance and repairs are made. Appendix J, Option B, is utilized. The Containment leak rate tests are performed in accordance with the guidelines contained in NRC Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program* [Reference 1], as modified by approved exceptions; and Nuclear Energy Institute (NEI) 94-01, *Industry Guidance for Implementing Performance-Based Options of 10 CFR Part 50 Appendix J* [Reference 2].

18.1.2 Aboveground Steel Tanks Inspection Program

The Aboveground Steel Tanks Inspection Program manages the effects of loss of material and cracking on the outside and inside surfaces of aboveground tanks constructed on concrete or soil. Tanks included in the program are the steel diesel fuel oil storage tank (outdoor tank) and the stainless steel borated water storage tank (outdoor tank) and the steel condensate storage tanks (indoor tanks). If the tank exterior is fully visible, the tank's outside surfaces may be inspected under the program for inspection of external surfaces (GALL Report AMP XI.M36) for visual inspections recommended in this AMP; surface examinations are conducted in accordance with the recommendations of this AMP. This program credits the standard industry practice of coating or painting the external surfaces of steel tanks as a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor degradation of the protective paint or coating. Tank inside surfaces are inspected by visual or surface examinations as required to detect applicable aging effects.

For storage tanks supported on earthen or concrete foundations, corrosion may occur at inaccessible locations, such as the tank bottom. Accordingly, verification of the effectiveness of the program is performed to ensure that significant degradation in inaccessible locations is not occurring and that the component's intended function is maintained during the period of extended operation. An acceptable verification program consists of thickness measurements of the tank bottom surface.

The Aboveground Steel Tanks Inspection Program includes preventive measures to mitigate corrosion by protecting the external surface of steel components per standard industry practice and with sealant or caulking at the interface of concrete and the diesel fuel oil storage tank. The Aboveground Steel Tanks Inspection Program is a condition monitoring program that consists of periodic visual inspections of tank external surfaces, and volumetric examinations of tank bottoms. Additional opportunistic tank bottom inspections will be performed whenever the tanks are drained. The tank bottom inspections will verify the effectiveness of the program by measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring.

Tank inspections are conducted in accordance with Table 4a, "Tank Inspection Recommendations," of License Renewal Interim Staff Guidance (LR-ISG) LR-ISG-2012-02, *Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation* [Reference 3].

Inspections for the borated water storage tank (BWST) include examination of the exterior surface of the insulation for indications of damage to the protective outer layer of the insulation. The inspections are performed during each 10-year period of the period of extended operation. If these inspections reveal damage to the exterior surface of the insulation, or there is evidence of water intrusion through the insulation, under-the-insulation inspections (bare metal inspection of the BWST exterior surface) for loss of material and cracking are conducted. For the under-the-insulation inspections, sufficient insulation is removed to determine the condition of the exterior surface of the tank. At a minimum, either 25 1-square-foot sections or 20 percent of the surface area of insulation is removed to permit inspection of the exterior surface of the tank. The sample inspection points are distributed in such a way that inspections are performed near the tank bottom, at points where structural supports, pipe or instrument nozzles penetrate the insulation and where water could collect, such as on top of stiffening rings. In addition, inspection locations are based on the likelihood of corrosion under insulation occurring.

18.1.3 Air Quality Monitoring Program

The Air Quality Monitoring Program is a preventive program that is implemented via periodic sampling of the air for hydrocarbons, dew point and particulates. The Air Quality Monitoring Program ensures that the system remains dry and free of contaminants, such that there are no aging effects which require management.

18.1.4 Bolting Integrity Program

The Bolting Integrity Program is a combination of existing activities that rely on manufacturer and vendor information, as well as on industry recommendations, such as contained in EPRI Technical Reports TR-104213, *Bolted Joint Maintenance and Applications Guide* [Reference 4] and TR-111472, *Assembling Bolted Connections Using Spiral Wound Gaskets* [Reference 5], for a comprehensive bolting and bolting maintenance program addressing proper selection, assembly and maintenance of bolting for pressure-retaining closures and structural connections. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

The Bolting Integrity Program includes, through the Inservice Inspection Program, Inservice Inspection (ISI) Program – IWE, Inservice Inspection (ISI) Program – IWF, Structures Monitoring Program and External Surfaces Monitoring Program, the periodic inspection of bolting for indications of degradation such as leakage, loss of material due to corrosion, loss of preload, and cracking.

18.1.5 Boral® Monitoring Program

The Boral® Monitoring Program detects degradation of Boral® neutron absorbers in the spent fuel storage racks by in situ testing. From the monitoring data, the stability and integrity of Boral® in the storage cells are assessed.

18.1.6 Boric Acid Corrosion Program

The Boric Acid Corrosion Program manages the effects of boric acid leakage on the external surfaces of structures and components potentially exposed to boric acid leakage. The Boric Acid Corrosion Program is a condition monitoring program consisting of visual inspections.

The Boric Acid Corrosion Program manages loss of material due to boric acid corrosion. The program includes provisions to identify, inspect, examine and evaluate leakage, and initiate corrective action. The program relies in part on implementation of recommendations of NRC Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Components in PWR Plants* [Reference 6]. The Boric Acid Corrosion Program ensures that the pressure boundary integrity and material condition of the subject structures and components are maintained consistent with the current licensing basis during the period of extended operation.

The Boric Acid Corrosion Program includes:

- a. visual inspection of external surfaces that are potentially exposed to borated water leakage;
- b. timely discovery of leak path and removal of the boric acid residues;
- c. assessment of the damage; and
- d. follow-up inspection for adequacy.

18.1.7 Buried and Underground Piping and Tanks Program

The Buried and Underground Piping and Tanks Program manages the loss of material from the external surfaces of piping and tanks exposed to a buried environment. The program also manages the aging of the external surfaces of underground piping. The program includes protective coatings for buried steel piping and tanks, backfill quality and cathodic protection as preventive measures to mitigate corrosion.

The program also includes visual inspections of the pipe or tank from the exterior as permitted by opportunistic or directed excavations. If damage to the protective coatings is found and the piping surface is exposed, the pipe or tank is inspected for loss of material due to general, pitting, crevice or microbiologically influenced corrosion. If corrosion has occurred, the wall thickness will be determined.

The program includes verification of the effectiveness of the cathodic protection system, and monitoring the jockey fire pump operation or equivalent parameter. The program also manages buried fire protection system bolting through opportunistic inspections.

Preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings and cathodic protection.

The minimum number of buried in-scope piping inspections during the 30-40, 40-50, and 50-60 year operating period is one steel piping segment. Each inspection will have a minimum of 10 feet of piping inspected.

A visual inspection of the underground piping within the borated water piping trench will be performed during the 30-40, 40-50, and 50-60 year operating periods.

Degradation or leakage found during inspections is entered into the Corrective Action Program to ensure evaluations are performed and appropriate corrective actions are taken. If adverse indications are detected, additional inspections will be performed in order to provide reasonable assurance of the integrity of the piping and tanks. The selection of components to be examined will be based on previous examination results, trending, risk ranking, and areas of cathodic

protection failures or gaps, if applicable. Additional sampling continues until reasonable assurance of the integrity of the piping and tanks is provided.

18.1.8 Closed Cooling Water Chemistry Program

The Closed Cooling Water Chemistry Program mitigates damage due to loss of material, cracking, and reduction in heat transfer of components that are within the scope of license renewal and contain closed cooling water. The program manages the relevant conditions that could lead to the onset and propagation of a loss of material, cracking or reduction in heat transfer through proper monitoring and control of corrosion inhibitor concentrations consistent with the current EPRI water chemistry guideline.

Also, the Closed Cooling Water Chemistry Program includes corrosion rate measurement at selected locations in the closed cooling water systems. In addition, periodic inspections of opportunity will be conducted when components are opened for maintenance, repair, or surveillance, to ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. A representative sample of piping and components will be inspected on a 10-year interval, with the first inspection taking place prior to the period of extended operation. Systems within the scope of this program are monitored for the presence of microbiological activity in accordance with the EPRI Closed-Cycle Cooling Water guidelines. Component cooling water radiochemistry is sampled on a weekly interval to verify the integrity of the letdown coolers and seal return coolers.

18.1.9 Collection, Drainage, and Treatment Components Inspection Program

The Collection, Drainage, and Treatment Components Inspection Program consists of visual and volumetric inspections. This program will be implemented via periodic inspections of a representative sample. These inspections will ensure that the existing environmental conditions in collection, drainage, and treatment service are not causing material degradation that could result in a loss of component intended function during the period of extended operation. Visual inspections will be conducted using visual (VT 1 or equivalent) inspection methods, capable of detecting loss of material, cracking, or reduction in heat transfer. This program will also include volumetric inspections of inaccessible surfaces (e.g., tank bottoms sitting on concrete). The aging effects for elastomers, exposed to raw water, will be monitored through a combination of visual inspection and manual or physical manipulation (at least 10% percent of available surface) of the material. Inspections will be performed by qualified personnel following procedures consistent with the pertinent American Society of Mechanical Engineers (ASME) code of record and 10 CFR 50, Appendix B.

18.1.10 Cranes and Hoists Inspection Program

The Cranes and Hoists Inspection Program manages loss of material for structural components and loss of preload for bolted connections of cranes (including bridge, trolley, rails, and girders), monorails, and hoists within the scope of license renewal through periodic visual inspection of structural members for signs of corrosion and wear and bolted connections for loose bolts and missing or loose nuts. The cranes, monorails and hoists within the scope of license renewal are those defined by NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants* [Reference 7], and light load handling systems related to refueling.

The Cranes and Hoists Inspection Program is based on guidance contained in American National Standards Institute (ANSI) B30.2, *Overhead and Gantry Cranes* [Reference 8], ANSI

B30.11, *Monorail Systems and Underhung Cranes* [Reference 9], ANSI B30.16, *Overhead Hoists (Underhung)* [Reference 10], and ANSI B30.22, *Articulating Boom Cranes* [Reference 11]. The program includes a review of the number and magnitude of lifts made by a crane, monorail or hoist.

18.1.11 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Inspection

The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Inspection provides reasonable assurance that the intended functions of the metallic parts of electrical cable connections that are not subject to the environmental qualification requirements of 10 CFR 50.49 and 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 are maintained consistent with the current licensing basis through the period of extended operation.

Cable connections are used to connect cable conductors to other cable conductors or electrical devices. Connections associated with cables within the scope of license renewal including high voltage connections are part of 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 program focuses on the metallic parts of the electrical cable connections. This program provides a one-time inspection, on a sampling basis, to ensure that either aging of metallic cable connections is not occurring and/or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. The one-time inspection confirms the absence of age-related degradation of cable connections resulting in increased resistance of connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, or oxidation.

Implementation of this inspection provides added assurance that the electrical connections in the plant have electrical continuity and are not overheating due to increased resistance (from a loosened or degraded connection). The inspection is performed via the use of thermography, with the optional use of contact resistance testing as a supplement.

18.1.12 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages the aging of cables and connections that are not required to be environmentally qualified but are within the scope of license renewal and subject to adverse localized environments.

Cables and connections subject to an adverse localized environment are managed by visual inspection. Accessible electrical cables and connections installed in adverse localized environments are visually inspected for signs of accelerated age-related degradation such as embrittlement, discoloration, cracking, or surface contamination.

18.1.13 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program manages the potential

loss of insulation resistance for high voltage, low current, sensitive instrument circuits that are subject to adverse localized environments (heat, radiation, and moisture in the presence of oxygen). The program is applicable to in-scope neutron monitoring and radiation monitoring circuits and utilizes testing of the cable assemblies for the subject circuits to determine if the cable insulation resistance is degrading.

18.1.14 Environmental Qualification (EQ) of Electrical Components Program

The Environmental Qualification (EQ) of Electrical Components Program implements the requirements of 10 CFR 50.49 (as further defined and clarified by the Division of Operating Reactors (DOR) Guidelines, *Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors* [Reference 12], NUREG-0588, *Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment* [Reference 13], Regulatory Guide 1.89, *Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants*, [Reference 14], and Regulatory Guide 1.97, *Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* [Reference 15]). The program demonstrates that subject electrical components located in harsh plant environments are qualified to perform their safety functions in those harsh environments, consistent with 10 CFR 50.49 requirements. The program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations. The program requires action to be taken before individual components in the scope of the program exceed their qualified life. Actions taken to maintain qualification include replacement of piece parts, replacement of complete components, or reanalysis.

As required by 10 CFR 50.49, EQ components not qualified to the end of the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Some aging evaluations for EQ components specify a qualification of at least 40 years and are considered time-limited aging analyses for license renewal. The program ensures that these EQ components are maintained within the bounds of their qualification bases.

Reanalysis of an aging evaluation to extend a component qualification is performed on a routine basis as part of the program. Important attributes for the reanalysis of an aging evaluation include analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

18.1.15 External Surfaces Monitoring Program

The External Surfaces Monitoring Program manages the aging of external surfaces, and internal surfaces in cases where environment is the same, of mechanical components within the scope of license renewal.

The External Surfaces Monitoring Program is a condition monitoring program that consists of periodic visual inspections and surveillance activities of component external surfaces to manage cracking and loss of material. The program includes components located in plant systems within the scope of license renewal that are constructed of aluminum, copper alloy (copper, brass, bronze, and copper-nickel), stainless steel (including cast austenitic stainless steel (CASS)), and steel (carbon and low-alloy steel and cast iron) materials. Cracking and loss of material from the external surfaces of these metals will be evidenced by surface irregularities, leakage, or localized discoloration and be detectable prior to loss of intended function. Surfaces that are inaccessible or not readily visible during either normal plant operations or refueling outages are inspected opportunistically during the period of extended operation. Surfaces that

are accessible are inspected at a frequency not to exceed one refueling cycle. System inspection and walkdown documentation includes inspection parameters and acceptance criteria for polymers, elastomers and metallic components as applicable. This documentation is retained in plant records.

Outdoor insulated components, and indoor insulated components exposed to condensation (because the in-scope component is operated below the dew point), have portions of the insulation inspected or removed to determine whether the exterior surface of the component is degrading or has the potential to degrade. A minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator), is inspected after the insulation is removed. Alternatively any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. The inspections will be conducted during each 10-year period of the period of extended operation. The following are alternatives to removing insulation:

- a. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer of the insulation when the results of the initial inspection meet the following criteria:
 1. No loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction is observed, and
 2. no evidence of stress corrosion cracking (SCC) is observed.

If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation should continue as conducted for the initial inspection.

- b. 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 corrosion under insulation (CUI) is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited towards the inspection quantities for other types of insulation.

The External Surfaces Monitoring Program, supplemented by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program, performs inspection and surveillance of elastomers and polymers that are exposed to air-indoor uncontrolled and air-outdoor environments, but are not replaced on a set frequency or interval (i.e., are long-lived), for evidence of cracking, change in material properties (hardening and loss of strength), and loss of material due to wear. The aging effects for elastomers are monitored through a combination of visual inspection and manual or physical manipulation (at least 10% of available surface) of the

material. Acceptance criteria for these components consists of no unacceptable visual indications of cracks or discoloration that would lead to loss of function prior to the next scheduled inspection and of no hardening as evidenced by a loss of suppleness during manipulation.

The External Surfaces Monitoring Program performs inspection and surveillance of the CREVS air-cooled condensing unit cooling coil tubes and fins and the SBODG radiator tubes and fins for visible evidence of external surface conditions that could result in a reduction in heat transfer. Acceptance criteria for these components consists of no unacceptable visual indications of fouling (build-up of dirt or other foreign material) that would lead to loss of function prior to the next scheduled inspection.

The External Surfaces Monitoring Program manages cracking of copper alloys with greater than 15 percent zinc and stainless steel components exposed to an outdoor air environment through plant system inspections and walkdowns for evidence of leakage. Acceptance criteria for surfaces consists of no unacceptable visual indications of cracks that would lead to loss of function prior to the next scheduled inspection.

18.1.16 Fatigue Monitoring Program

The Fatigue Monitoring Program manages fatigue of select primary and secondary components, including the reactor vessel, reactor internals, pressurizer, and steam generators by monitoring and tracking the number of critical thermal and pressure transients as required by Technical Specifications, Section 5.5.5, *Allowable Operating Transient Cycles Program*. The scope includes those components that have been identified to have a fatigue time-limited aging analysis (TLAA).

The program prevents the fatigue TLAA's from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the Code design limit of 1.0, including environmental effects where applicable. The program uses the systematic counting of transient cycles and the evaluation of operating data to ensure that the allowable cycle limits are not exceeded, thereby ensuring that component fatigue usage limits are not exceeded. Transient documentation is updated at least once per plant operating cycle.

When the accumulated cycles approach the allowable cycles, corrective action is taken that includes an engineering evaluation to ensure the Code design limit of 1.0 is not exceeded. The program provides for updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached. When the number of accrued cycles is within 75% of the allowable cycle limit for any transient, a condition report shall be generated. For transient cycles that are projected to exceed the allowable cycle limit by the end of the next plant operating cycle (DBNPS operating cycles are normally two years in duration), the program requires an update of the fatigue usage calculation for the affected component(s). Acceptance criterion is to maintain the cumulative fatigue usage below the Code design limit of 1.0 through the period of extended operation, including environmental effects where applicable.

For license renewal, the effects of the reactor coolant environment on component fatigue life have been addressed by assessing the impact of the environment on a sample of critical components as identified in NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components* [Reference 16]. Environmental effects were evaluated in accordance with NUREG/CR-6260 and the guidance of EPRI Technical Report 1012017 (MRP-47), *Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application* [Reference 17]. Components identified in NUREG/CR-6260 were

evaluated using material specific guidance presented in NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low Alloy Steels* [Reference 18], and in NUREG/CR-5704, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels* [Reference 19]. Nickel-based alloy components were evaluated using material specific guidance presented in NUREG/CR-6909, *Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials* [Reference 20].

In addition, the Fatigue Monitoring Program will evaluate additional plant-specific component locations in the reactor coolant pressure boundary that may be more limiting than those considered in NUREG/CR-6260. This evaluation will include identification of the most limiting fatigue location exposed to reactor coolant for each material type (i.e., carbon steel, low-alloy steel, stainless steel and nickel-based alloys), and that each bounding material/location will be evaluated for the effects of the reactor coolant environment on fatigue usage. Nickel-based alloy items will be evaluated using NUREG/CR-6909. This evaluation will be submitted to the NRC one year prior to the period of extended operation.

18.1.17 Fire Protection Program

The Fire Protection Program is a combination condition and performance monitoring program, comprised of tests and inspections that follow the applicable National Fire Protection Association (NFPA) recommendations. The Fire Protection Program manages, through visual inspections and functional tests, as appropriate, the aging effects on fire barrier penetration seals, fire wraps, fire-rated doors and fire barrier walls, ceilings, and floors that perform a current licensing basis fire barrier intended function. The Fire Protection Program also supplements the Fuel Oil Chemistry Program for managing the aging effects on the diesel fire pump fuel oil supply line.

18.1.18 Fire Water Program

The Fire Water Program (a sub-program of the overall Fire Protection Program) is an existing program that applies to the fire water supply and water-based suppression systems, which include sprinklers, nozzles, fittings, valve bodies, fire pump casings, hydrants, hose stations, standpipes, a water storage tank, and aboveground, buried and underground piping and components. This program is a condition monitoring program.

The Fire Water Program manages loss of material due to corrosion, including MIC, fouling, and flow blockage because of fouling. This program manages the aging effects through the use of flow testing and visual inspections performed in accordance with the 2011 Edition of NFPA 25, *Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems* [Reference 21]. Testing or replacement of sprinklers that have been in place for 50 years is performed in accordance with the 2011 Edition of NFPA 25. In addition to NFPA codes and standards, portions of the water-based fire protection system that are: (a) normally dry but periodically subjected to flow (e.g., dry-pipe or preaction sprinkler system components) and (b) cannot be drained or allow water to collect are to be subjected to augmented testing beyond that specified in NFPA 25, including: (a) periodic full flow tests at the design pressure and flow rate or internal visual inspections and (b) volumetric wall-thickness examinations. Flow testing and visual inspections are performed at intervals specified in the 2011 Edition of NFPA 25. The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated.

18.1.19 Flow-Accelerated Corrosion (FAC) Program

The Flow-Accelerated Corrosion (FAC) Program manages loss of material for steel components that are within the scope of license renewal and are exposed to single phase water above 200°F or two phase steam at any temperature in systems that are susceptible to flow-accelerated corrosion, also called erosion-corrosion. The FAC Program combines the elements of predictive analysis, baseline inspections, and periodic inspections (to monitor wall-thinning) to monitor and predict wall thickness in susceptible locations. The program is a condition monitoring program that implements the recommendations of NRC Generic Letter 89-08, *Erosion/Corrosion – Induced Pipe Wall Thinning* [Reference 22] and follows the guidance and recommendations of EPRI Report 3002000563 (NSAC-202L), *Recommendations for An Effective Flow Accelerated Corrosion Program (NSAC-202L-R4)* [Reference 23], to ensure that the integrity of piping systems susceptible to flow-accelerated corrosion is maintained.

18.1.20 Fuel Oil Chemistry Program

The Fuel Oil Chemistry Program monitors and maintains fuel oil quality to mitigate damage due to loss of material, as well as due to cracking of susceptible materials, for the storage tanks and associated piping and components containing fuel oil that are within the scope of license renewal. The program includes verifying the quality of new fuel oil, periodic sampling of stored diesel fuel oil, and periodic cleaning and inspection of the emergency diesel generator fuel oil storage tanks and day tanks, diesel oil storage tank, diesel fire pump day tank, and station blackout diesel generator day tank. The fuel oil tanks are periodically drained (at least once every 10 years) for cleaning and are visually inspected to detect potential degradation. If degradation is identified in a diesel fuel tank by visual inspections, a volumetric inspection is performed.

The Fuel Oil Chemistry Program manages the presence of contaminants, such as water or microbiological organisms, that could lead to the onset and propagation of loss of material or cracking (of susceptible material) through proper monitoring and control of fuel oil contamination consistent with plant Technical Specifications and ASTM standards D975, D2276, D2709, D4057 and D4176. Water and particulate contamination concentrations are monitored and trended in accordance with the plant's Technical Specifications. Biological activity is monitored and trended at least quarterly. The Fuel Oil Chemistry Program is a mitigation program.

The effectiveness of the Fuel Oil Chemistry Program is verified by the One-Time Inspection, which includes ultrasonic thickness measurement of a sample of fuel oil tank bottoms.

18.1.21 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

The Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program manages reduced insulation resistance of inaccessible or underground power cables (greater than or equal to 400 volt) that are exposed to significant moisture, such that there is reasonable assurance that the cables will perform their intended function in accordance with the current licensing basis through the period of extended operation. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable wetting or submergence in water).

At least once every 6 years, for power cables from 600 VAC to 13.8 kV, and 8 years, for power cables from 400 VAC to 600 VAC, these cables are tested to provide an indication of the condition of the conductor insulation. Testing will be evaluated for more or less frequent

performance intervals based on test results, operating experience, and industry consensus. The program also requires periodic inspection of electrical manholes associated with in-scope cables for water accumulation and requires the removal of water from the electrical manholes as necessary. Inspections are performed at least annually and are also performed in response to event-driven occurrences (such as heavy rain or flooding). The inspection frequency for water collection is established and performed based on plant-specific operating experience with cable wetting or submergence.

18.1.22 Inservice Inspection (ISI) Program – IWE

The Inservice Inspection (ISI) Program – IWE establishes responsibilities and requirements for conducting ASME Code, Section XI, Subsection IWE (IWE) inspections as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWE includes examination and testing of accessible surface areas of the steel containment; containment hatches and airlocks; seals, gaskets and moisture barriers; and containment pressure-retaining bolting in accordance with the requirements of IWE.

Fatigue analyses were performed for stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading, and these components, therefore, no longer require surface examinations. The 10 CFR Part 50 Appendix J Program provides for verification that a general visual inspection of the accessible interior and exterior surfaces of the primary containment and components (includes penetrations) has been performed prior to the Integrated Leak Rate Test (ILRT) pressurization to identify evidence of structural deterioration that might affect either the primary containment structural integrity or leak tightness.

The inservice examinations conducted throughout the service life of DBNPS will comply with the requirements of the ASME Code Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC.

18.1.23 Inservice Inspection (ISI) Program – IWF

The Inservice Inspection (ISI) Program – IWF establishes responsibilities and requirements for conducting ASME Code, Section XI, Subsection IWF (IWF) inspections as required by 10 CFR 50.55a. The Inservice Inspection (ISI) Program – IWF includes visual examination of supports based on sampling of the total support population. The sample size varies depending on the ASME Class. The largest sample size is specified for the most critical supports (ASME Class 1). The sample size decreases for the less critical supports (ASME Classes 2 and 3). The primary inspection method is visual examination. Degradation that potentially compromises support function or load capacity is identified for evaluation. Supports determined to be unacceptable for continued service requiring corrective actions are re-examined during the next inspection period in accordance with the requirements of IWF.

The Inservice Inspection (ISI) Program - IWF includes monitoring of ASTM A490 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch nominal diameter for cracking using volumetric examination. The volumetric examinations are performed in accordance with the requirements of ASME Code Section V, Article 5, Appendix IV. The representative sample size is equal to 20 percent (rounded up to the nearest whole number) of the entire IWF population of ASTM A490 high strength bolts in sizes greater than 1 inch nominal diameter, with a maximum sample size of 25 bolts. The selection of the representative sample considers susceptibility to stress corrosion

cracking (e.g., actual measured yield strength) and ALARA principles. The frequency of examination is once for each 10-year ISI Interval beginning with the 4th Interval that started September 21, 2012.

The Inservice Inspection (ISI) Program - IWF includes monitoring of ASTM A540 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch in nominal diameter for cracking. Periodic visual inspections of susceptible ASTM A540 bolting are conducted prior to the period of extended operation and at an interval not to exceed five years to identify locations where the A540 bolting may be exposed to a potentially corrosive environment for stress corrosion cracking. If the visual inspections identify one or more bolts in a potentially corrosive environment, then an engineering evaluation is performed to determine whether the bolting material had been subjected to a corrosive environment for stress corrosion cracking. The bolts determined to have been subjected to a corrosive environment for stress corrosion cracking comprise the population subject to sampling for volumetric examinations. The representative sample size is equal to 20 percent (rounded up to the nearest whole number) of the bolts in the sample population, with a maximum sample size of 25 bolts. The volumetric examinations are performed in accordance with the requirements of ASME Code Section V, Article 5, Appendix IV. Volumetric examinations will be performed no later than the subsequent refueling outage following visual identification of bolting subject to a corrosive environment. Deferral of volumetric examinations to the subsequent refueling outage is not permitted if the visual inspection indicates evidence of contaminant penetration through the coatings. The frequency of examination is once for each 10-year ISI Interval beginning with the 4th interval that started on September 21, 2012. For ASTM A540 high strength bolts that are not exposed to a corrosive environment, the volumetric examinations are waived based on plant-specific operating experience associated with the volumetric examination of the DBNPS reactor head closure studs (60 each) constructed of ASTM A540 material where the studs are examined once for each ISI interval and after three intervals, no unacceptable indications have been noted.

As an alternative to the visual examinations and the subsequent volumetric examinations of ASTM A540 bolts subjected to a corrosive environment, the Inservice Inspection (ISI) Program - IWF provides an option to perform periodic volumetric examinations as follows. The program includes monitoring of ASTM A540 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch nominal diameter for cracking using volumetric examination. The volumetric examinations are performed in accordance with the requirements of ASME Code Section V, Article 5, Appendix IV. The representative sample size is equal to 20 percent (rounded up to the nearest whole number) of the entire IWF population of ASTM A540 high strength bolts in sizes greater than 1 inch nominal diameter, with a maximum sample size of 25 bolts. The selection of the representative sample considers susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA principles. The frequency of examination is once for each 10-year ISI Interval beginning with the 4th interval that started on September 21, 2012.

The inservice examinations conducted throughout the service life of DBNPS will comply with the requirements of the ASME Code Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC.

18.1.24 Inservice Inspection Program

The Inservice Inspection Program manages cracking of reactor coolant pressure boundary components and once-through steam generator secondary-side components. The Inservice

Inspection Program also manages reduction in fracture toughness of cast austenitic stainless steel pump casings and valve bodies. In addition, the Inservice Inspection Program, in conjunction with the PWR Water Chemistry Program, manages loss of material for once-through steam generator secondary-side components.

The Inservice Inspection Program is a condition monitoring program that meets the inservice inspection requirements specified by the ASME Code, Section XI, Division 1, including Subsections IWB, IWC, and IWD, as modified by 10 CFR 50.55a. The Inservice Inspection Program includes augmented examinations that correspond to commitments made to the regulatory authorities beyond the ASME Code requirements.

The inservice examinations (and pressure tests) conducted throughout the service life of DBNPS will comply with the requirements of the ASME Code Section XI, Subsections IWB, IWC, and IWD, Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) twelve months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC.

18.1.25 Leak Chase Monitoring Program

The Leak Chase Monitoring Program is a condition monitoring program, consisting of observation and activities to detect leakage from the spent fuel pool, the fuel transfer pit, and the cask pit liners due to age-related degradation.

The Leak Chase Monitoring Program includes periodic monitoring of the spent fuel pool, the fuel transfer pit, and the cask pit liners leak chase system. Periodic monitoring of leakage from the leak chase system permits early determination and localization of leakage. In conjunction with the PWR Water Chemistry Program, and, for the spent fuel pool, Technical Specifications requirements for monitoring spent fuel pool level, the Leak Chase Monitoring Program is credited for managing the loss of material aging effect in the treated borated water environment for the stainless steel spent fuel pool, the fuel transfer pit, and the cask pit liners. Loss of material due to crevice or pitting corrosion can occur at weld seams. The program detects and monitors leakage prior to loss of intended function. Measurement of leakage from any monitoring line exceeding 25 milliliters per minute will be documented in a condition report for evaluation and potential corrective actions. Evaluation will include consideration of more frequent monitoring.

The Leak Chase Monitoring Program includes analysis of the leakage from the leak chase system for pH monthly and for iron every six months. The results for pH and iron will be trended and analyzed to look for indication of blockage forming in the SFP leakchase monitoring system, contact with concrete, and reaction with the steel leakchase channel. Measurement of pH outside the range of 6.0-10.0 or iron exceeding 2500 ppm from any monitoring line will be documented in a condition report for evaluation and potential corrective actions.

The leak chase system preventive maintenance (PM) activity to inspect and clean the leakage pathways is performed at least every 18 months based on plant-specific operating experience. Additionally, the program requires inspections once per year of the accessible outside walls and floor (from the ceiling side) of the pool and pits. This inspection will be a documented inspection performed with the specific intent of identifying indications of leakage migrating through the walls. Indication of leakage through the walls will be documented in the Corrective Action Program.

18.1.26 Lubricating Oil Analysis Program

The Lubricating Oil Analysis Program mitigates age-related degradation due to loss of material and reduction in heat transfer due to fouling for plant components that are within the scope of license renewal and that are exposed to a lubricating oil environment. The program requires management of the relevant conditions that could lead to the onset and propagation of loss of material due to crevice, galvanic, general, or pitting corrosion, selective leaching, or reduction in heat transfer due to fouling, through monitoring of the lubricating oil consistent with various manufacturers' recommendations and industry standards. The Lubricating Oil Analysis Program is a mitigation program.

The Lubricating Oil Analysis Program is supplemented by the One-Time Inspection, which provides verification of the effectiveness of the program in mitigating the effects of aging.

18.1.27 Masonry Wall Inspection

The Masonry Wall Inspection, implemented as part of the Structures Monitoring Program, consists of inspection activities to detect cracking of masonry walls and degradation of steel edge supports or bracing on masonry walls within the scope of license renewal. Masonry walls that perform a fire barrier intended function are also managed by the Fire Protection Program. The Masonry Wall Inspection performs visual inspection of external surfaces of masonry walls.

18.1.28 Nickel-Alloy Management Program

The Nickel-Alloy Management Program manages primary water stress corrosion cracking (PWSCC) and stress corrosion cracking / intergranular attack (SCC/IGA) of nickel-alloy pressure boundary components other than reactor vessel closure head nozzles and steam generator tubes. The Nickel-Alloy Management Program is a combination mitigative and condition monitoring program.

The Nickel-Alloy Management Program uses a number of inspection techniques to detect cracking, including volumetric and bare metal visual examinations. The Nickel-Alloy Management Program implements the inspection of components through the Inservice Inspection Program. Component evaluations, examination methods, scheduling, and site documentation comply with 10 CFR 50, the ASME Code, NRC Bulletins and Generic Letters, and staff-approved industry guidelines related to nickel-alloy issues. Inspection of dissimilar metal butt welds are conducted in accordance with the requirements of ASME Code Case N-770-1, *Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities, Section XI, Division 1* [Reference 24], as modified by the Code of Federal Regulations, 10 CFR 50.55a Section (g)(6)(ii)(F).

The Nickel-Alloy Management Program includes mitigation and repair activities to ensure long-term operability of nickel-alloy components.

18.1.29 Nickel-Alloy Reactor Vessel Closure Head Nozzles Program

The Nickel-Alloy Reactor Vessel Closure Head Nozzles Program manages cracking of the control rod drive nozzles and welds in the reactor vessel closure head, and the Boric Acid Corrosion Program manages wastage of associated reactor vessel closure head surfaces. The Nickel-Alloy Reactor Vessel Closure Head Nozzles Program ensures that inservice inspections of all nickel-alloy reactor vessel closure head penetration nozzles, and associated reactor vessel closure head surfaces, will continue to be performed in accordance with ASME Code Case N-729-1, *Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1* [Reference 25], as modified by 10 CFR 50.55a Section (g)(6)(ii)(D).

18.1.30 One-Time Inspection

One-Time Inspection performs inspections to verify the effectiveness of the Fuel Oil Chemistry Program, the Lubricating Oil Analysis Program, and the PWR Water Chemistry Program, or confirms the absence of aging effects. One-time inspections address situations where:

1. An aging effect is not expected to occur, but it cannot be ruled out with reasonable assurance, or
2. An aging effect is expected to progress very slowly in the specified environment, but the local environment may be more adverse.

One-Time Inspection also provides assurance that aging which has not yet manifested itself is indeed not occurring, or that the age-related degradation is so insignificant that an aging management program is not warranted.

The elements of One-Time Inspection include:

- Determination of a representative sample size based on an assessment of materials of fabrication, environment, plausible aging effects, and operating experience;
- Identification of the inspection locations in the system or component based on the aging effect, or based on the areas susceptible to concentration of contaminants that promote certain aging effects;
- Determination of the examination technique, including acceptance criteria that is effective in managing the aging effect for which the component is examined; and
- Evaluation of the need for follow-up examinations to monitor the progression of any age-related degradation.

When evidence of an aging effect is revealed by a one-time inspection, the routine evaluation of the inspection results triggers corrective actions to assure the intended function of affected components will be maintained through the period of extended operation.

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

18.1.31 Open-Cycle Cooling Water Program

The Open-Cycle Cooling Water Program manages loss of material due to crevice, galvanic, general, pitting and microbiologically-influenced corrosion; and erosion for in-scope components in the Service Water System and components connected to or cooled by the Service Water System (including the cooling tower makeup water relative to the Circulating Water System). The program also manages fouling due to particulates (e.g., corrosion products) and biological material (micro- and macro-organisms) resulting in reduction in heat transfer for heat exchangers (including condensers, coolers, cooling coils, and evaporators) within the scope of the program.

The Open-Cycle Cooling Water Program consists of inspections, surveillances, and testing to detect and evaluate fouling and loss of material, combined with chemical treatments and cleaning activities to minimize fouling and loss of material. The program is a combination condition and performance monitoring, and mitigation program that implements the recommendations of NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment* [Reference 26], for safety-related equipment in the scope of the program, and manages loss of material for in-scope nonsafety-related components that contain service water or cooling tower makeup water.

18.1.32 PWR Reactor Vessel Internals Program

The PWR Reactor Vessel Internals Program relies on implementation of the Electric Power Research Institute (EPRI) Topical Report No. 1022863, *Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)* [Reference 27], and EPRI Topical Report No. 1016609, *Materials Reliability Program: Inspection Standard for PWR Internals (MRP-228)* [Reference 28], to manage the aging effects on the reactor vessel internal (RVI) components.

This program is used to manage the effects of age-related degradation mechanisms that are applicable in general to the PWR RVI components at DBNPS, a Babcock & Wilcox (B&W) designed plant. These aging effects include:

- a. various forms of cracking, including SCC, which also encompasses primary water stress corrosion cracking (PWSCC), irradiation-assisted stress corrosion cracking (IASCC), or cracking due to fatigue/cyclical loading;
- b. loss of material induced by wear;
- c. loss of fracture toughness due to either thermal aging or neutron irradiation embrittlement; and
- d. loss of preload due to thermal and irradiation-enhanced stress relaxation or creep.

In addition, the program includes management of the time-limited aging analysis (TLAA) identified in UFSAR Section 18.2.2.7 for reduction in fracture toughness of the reactor vessel internals. This TLAA will be managed in accordance with the implementation of the MRP-227 guidelines including all activities associated with the company's responses to plant-specific action items identified in Section 4.2 of the MRP-227 safety evaluation report.

Locations using replacement bolts, fabricated from Alloy X-750 material, are the upper core barrel (UCB), the lower core barrel (LCB), lower thermal shield (LTS) and surveillance specimen

holder tube (SSHT). These replacement bolts have cumulative usage factor analyses that are TLAAs and are managed by the PWR Reactor Vessel Internals Program where volumetric UT examinations are performed on a periodic basis consistent with the program's inspection plan.

The program applies the guidance in MRP-227 for inspecting, evaluating, and, if applicable, dispositioning non-conforming RVI components at DBNPS. The program conforms to the definition of a sampling-based condition monitoring program, as defined by the Branch Technical Position RSLB-1, with periodic examinations and other inspections of highly-affected internals locations. These examinations provide reasonable assurance that the effects of age-related degradation mechanisms will be managed during the period of extended operation. The program includes expanding periodic examinations and other inspections if the extent of the degradation effects exceeds the expected levels.

The MRP-227 guidance for selecting RVI components for inclusion in the inspection sample is based on a four-step ranking process. Through this process, the reactor internals were assigned to one of the following four groups: Primary, Expansion, Existing Programs, and No Additional Measures components. Definitions of each group are provided in NUREG-1801, Chapter IX.B.

The result of this four-step sample selection process is a set of Primary Internals Component locations for each of the three plant designs (Westinghouse, Combustion Engineering and Babcock & Wilcox) that are expected to show the leading indications of the degradation effects, with another set of Expansion Internals Component locations that are specified to expand the sample should the indications be more severe than anticipated. The degradation effects in a third set of internals locations are deemed to be adequately managed by Existing Programs. A fourth set of internals locations are deemed to require no additional measures. As a result, the program typically identifies 5 to 15 percent of the RVI locations as Primary Component locations for inspections, with another 7 to 10 percent of the RVI locations to be inspected as Expansion Components, as warranted by the evaluation of the inspection results. Another 5 to 15 percent of the internals locations are covered by Existing Programs, with the remainder requiring no additional measures. This process thus uses appropriate component functionality criteria, age-related degradation susceptibility criteria, and failure consequence criteria to identify the components that will be inspected under the program in a manner that conforms to the sampling criteria for sampling-based condition monitoring programs in Section A.1.2.3.4 of NRC Branch Position RLSB-1. Consequently, the sample selection process is adequate to assure that the intended function(s) of the PWR reactor internal components are maintained during the period of extended operation.

No existing generic industry programs contain the specificity considered sufficient for monitoring the aging effects addressed by the MRP-227 guidelines for B&W plants. Therefore, no components for B&W plants were placed into the Existing Programs group.

MRP-227 I&E guidelines require a visual (VT-3) examination of the core support shield (CSS) vent valve retaining rings for every 10 year Inservice Inspection Interval. In addition, DBNPS Technical Specification 5.5.4 requires testing of the CSS vent valves every 24 months to verify by visual inspection that the valve body and valve disc exhibit no abnormal degradation, verify the valve is not stuck in an open position, and verify by manual actuation that the valve is fully open when a force of ≤ 400 lbs. is applied vertically upward. The technical specification inspection will continue to be performed at the prescribed frequency of 24 months. The MRP-227 required visual (VT-3) examination will also be performed at the prescribed frequency of every 10 year Inservice Inspection Interval.

The program's use of visual examination methods in MRP-227 for detection of relevant conditions (and the absence of relevant conditions as a visual examination acceptance criterion) is consistent with the ASME Code, Section XI rules for visual examination. However, the program's adoption of the MRP-227 guidance for visual examinations goes beyond the ASME Code, Section XI visual examination criteria because additional guidance is incorporated into MRP-227 to clarify how the particular visual examination methods will be used to detect relevant conditions and describes in more detail how the visual techniques relate to the specific RVI components and how to detect their applicable age-related degradation effects.

The technical basis for detecting relevant conditions using volumetric ultrasonic testing (UT) inspection techniques can be found in MRP-228, where the review of existing bolting UT examination technical justifications has demonstrated the indication detection capability of at least two vendors, and where vendor technical justification is a requirement prior to any additional bolting examinations. Specifically, the capability of program's UT volumetric methods to detect loss of integrity of PWR internals bolts, pins, and fasteners, such as baffle-former bolting in B&W and Westinghouse units, has been well demonstrated by operating experience. In addition, the program's adoption of the MRP-227 guidance and process incorporates the UT criteria in MRP-228, which calls for the technical justifications that are needed for volumetric examination method demonstrations, required by the ASME Code, Section V.

The program also includes future industry operating experience as incorporated in periodic revisions to MRP-227. The program thus provides reasonable assurance for the long-term integrity and safe operation of reactor internals in all commercial operating U.S. PWR nuclear power plants.

Age-related degradation in the reactor internals is managed through an integrated program. Specific features of the integrated program are described in the license renewal program basis document. Degradation due to changes in material properties (e.g., loss of fracture toughness) was considered in the determination of inspection recommendations and is managed by the requirement to use appropriately degraded properties in the evaluation of identified defects. The integrated program is implemented through an inspection plan.

The DBNPS PWR Reactor Vessel Internals Program will address all plant-specific action items applicable to DBNPS that are established in Section 4.2 of the safety evaluation for MRP-227. In addition, a plant-specific inspection plan for ensuring the implementation of MRP-227 program guidelines and the company's responses to the plant-specific action items, as identified in Section 4.2 of the safety evaluation, will be submitted for NRC review and approval.

18.1.33 PWR Water Chemistry Program

The PWR Water Chemistry Program mitigates damage due to loss of material, cracking, and reduction in heat transfer of components that are within the scope of license renewal and contain, or are exposed to, treated water or steam in the primary, secondary, or auxiliary systems. The program includes periodic monitoring and control of the known detrimental contaminants that could lead to, or are indicative of, conditions for the onset and propagation of loss of material, cracking, or reduction in heat transfer through proper monitoring and control of chemical concentrations consistent with EPRI primary and secondary water chemistry guidelines.

In addition, the PWR Water Chemistry Program is credited in conjunction with the Nickel-Alloy Management Program, Inservice Inspection Program, Nickel-Alloy Reactor Vessel Closure Head Nozzles Program, PWR Reactor Vessel Internals Program, Steam Generator Tube

Integrity Program, and Small Bore Class 1 Piping Inspection to manage the effects of aging for reactor vessel, reactor vessel internals, reactor coolant pressure boundary, and steam generator components.

The PWR Water Chemistry Program is also supplemented by a One-Time Inspection to provide verification of the effectiveness of the program in managing the effects of aging.

18.1.34 Reactor Head Closure Studs Program

The Reactor Head Closure Studs Program manages cracking and loss of material for the reactor head closure stud assemblies (studs, nuts, and washers). The Reactor Head Closure Studs Program is a combination mitigative and condition monitoring program.

The Reactor Head Closure Studs Program includes the preventive measures of NRC Regulatory Guide 1.65, *Materials and Inspection for Reactor Vessel Closure Studs* [Reference 29], to mitigate cracking, including the use of a stable lubricant that is compatible with the fastener material and the environment. The program provides a specific precaution against the use of compounds containing sulfur (sulfide), including molybdenum disulfide (MoS₂), as a lubricant for the reactor head closure stud assemblies. An approved lubricant is applied to the threaded areas of studs and nuts and to the concave and convex faces of the spherical washers during each assembly. There are no metal platings applied to the closure studs, nuts, or washers. A manganese-phosphate coating was applied to the studs, nuts and washers during fabrication to act as a rust inhibitor and to assist in retaining lubricant. The program precludes the future use of replacement closure stud bolting fabricated from material with actual measured yield strength greater than or equal to 150 ksi except for use of the existing spare reactor head closure stud bolting.

The Reactor Head Closure Studs Program examines reactor vessel stud assemblies in accordance with the examination and inspection requirements specified in the ASME Code, Section XI, Subsection IWB (2007 Edition through the 2008 Addenda) and approved ASME Code Cases. Visual examinations (VT-2) for leak detection are performed during system pressure tests.

The Reactor Head Closure Studs Program inspections are implemented by the Inservice Inspection Program. The Inservice Inspection Program will continue to comply with the requirements of the ASME Code Section XI Edition and Addenda incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the inspection interval, subject to prior approval of the edition and addenda by the NRC.

18.1.35 Reactor Vessel Surveillance Program

The Reactor Vessel Surveillance Program is a condition monitoring program that manages reduction of fracture toughness for the low alloy steel reactor vessel shell and welds in the beltline region. The company participates in the Pressurized Water Reactor Owners Group (PWROG) Master Integrated Reactor Vessel Surveillance Program (MIRVSP), which includes all seven operating B&W 177-fuel assembly plants and six participating Westinghouse-designed plants having B&W fabricated reactor vessels. The MIRVSP is an NRC-approved program that implements the requirements of Appendix H to 10 CFR Part 50.

Data resulting from the Reactor Vessel Surveillance Program is used to:

- determine pressure-temperature limits, minimum temperature requirements, and end-of-life upper shelf energy (USE) in accordance with the requirements of 10 CFR 50 Appendix G, "Fracture Toughness Requirements," and
- determine end-of-life reference temperature for pressurized thermal shock (RT_{PTS}) values in accordance with 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock."

Six surveillance capsules containing DBNPS specific materials were inserted into the reactor before initial plant startup. These capsules were designated as TE1-A through TE1-F. The requirements of 10 CFR 50 Appendix H were met by the first four capsules having been withdrawn and tested. The remaining two capsules, TE1-C and TE1-E, have been removed and the TE1-E materials have not been tested. Capsule TE1-C contained the DBNPS limiting material and it was exposed to a fluence slightly above the 60-year projected fluence for DBNPS. The TE1-C capsule materials were tested and evaluated [Reference 36]. Capsule TE1-E has been discarded.

Since DBNPS does not have plant-specific surveillance capsules remaining inside the reactor vessel, ex-vessel cavity dosimetry is used to monitor neutron fluence.

18.1.36 Selective Leaching Inspection

The Selective Leaching Inspection detects and characterizes the conditions on internal and external surfaces of subject components exposed to air-outdoor, raw water, treated water, soil, and moist air (including condensation) environments. The inspection provides direct evidence through visual inspection, hardness measurement, or other appropriate examinations (such as chipping, scraping, or other mechanical means), of whether, and to what extent, loss of material due to selective leaching has occurred. The inspection activities will be conducted within the last five years prior to the period of extended operation.

18.1.37 Small Bore Class 1 Piping Inspection

The Small Bore Class 1 Piping Inspection is a one-time inspection that is designed to detect cracking of small bore ASME Code Class 1 piping less than 4 inches nominal pipe size (less than NPS 4) and greater than or equal to NPS 1, which includes pipe, fittings, and branch connections, and all full and partial penetration (socket) welds.

The DBNPS Small Bore Class 1 Piping Inspection consists of volumetric examination of a statistically significant sample of small bore piping locations (full penetration welds and socket welds) that are susceptible to cracking. Location selection is based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping (1 to < 4 inches NPS).

Volumetric examinations are performed using demonstrated techniques that are capable of detecting the aging effects in the examination volume of interest. For partial penetration (socket) welds, the inspection will be either a volumetric or opportunistic destructive examination. If a qualified volumetric examination procedure for socket welds endorsed by the industry and the NRC is available and incorporated into the ASME Code Section XI at the time of the small-bore socket weld inspections, then this is used for the volumetric examinations. Otherwise, the socket weld volumetric examinations shall follow guidelines set forth in ASME

Code Section V, Article 4, consistent with the guidelines for examination volume of ½ inch beyond the toe of the weld as established in EPRI Report 1011955, *Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)* [Reference 30]. Volumetric examinations are performed by qualified personnel following procedures that are consistent with Section XI of the ASME Code and 10 CFR 50, Appendix B.

DBNPS, performed the one-time inspection on small bore socket welds removed during the eighteenth refueling outage and identified cracking in a number of the welds. Therefore, after evaluation using the Corrective Action Program, periodic inspection was implemented using a plant-specific aging management program.

DBNPS performed the one-time inspection of small bore full penetration welds during the eighteenth and nineteenth refueling outages. No instances of cracking or other age-related degradation were identified. As in such, the ongoing, plant-specific, aging management program for Small Bore Class 1 Piping Inspection is limited only to partial penetration welds.

18.1.38 Steam Generator Tube Integrity Program

The Steam Generator Tube Integrity Program is credited for aging management of cracking, denting, loss of material, and reduction in heat transfer of the steam generator tubes, as well as cracking of the tube plugs and tube support plates.

The Steam Generator Tube Integrity Program is a combination condition monitoring and mitigation program. The Steam Generator Tube Integrity Program is based on the Steam Generator Management program, which meets the intent of the guidance in NEI 97-06, *Steam Generator Program Guidelines* [Reference 31], and the requirements of the Technical Specifications. The Steam Generator Tube Integrity Program also includes secondary-side examinations to assist in verification of tube integrity and the condition of the tube support plates. The program establishes a framework for prevention, inspection, evaluation, removal from service (plugged) and leakage monitoring measures.

Primary-side and secondary-side water chemistry control and foreign material exclusion requirements inhibit degradation. Eddy current testing and visual inspections are used for the detection of flaws. Condition monitoring compares the inspection results against performance criteria, and an operational assessment ensures that the performance criteria will be met throughout the next operating cycle.

18.1.39 Structures Monitoring Program

The Structures Monitoring Program manages age-related degradation of plant structures and structural components within the scope of the program to ensure that each structure or structural component retains the ability to perform its intended function. Aging effects are detected by visual inspection of external surfaces prior to the loss of the structures' or component's intended function. Visual inspections are supplemented by volumetric examination or by feel (for elastomers), as needed.

High strength (i.e., ASTM A540 Grade B23) structural bolting greater than 1 inch in nominal diameter, with an actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) or an undocumented yield strength, is monitored for stress corrosion cracking (SCC). Periodic visual inspections of susceptible ASTM A540 bolting are conducted at an interval not to exceed five years to identify locations where the A540 bolting may be exposed to

a potentially corrosive environment for SCC. If the visual inspections identify one or more bolts or studs in a potentially corrosive environment, then an engineering evaluation will be performed to determine whether the bolting material had been subjected to a corrosive environment for SCC. The bolts or studs determined to have been subjected to a corrosive environment for SCC comprise the population subject to sampling for volumetric examinations. The representative sample size is equal to 20 percent of the bolts or studs in the sample population (rounded up to the nearest whole number), with a maximum sample size of 25 bolts or studs.

The Structures Monitoring Program encompasses and implements the Water Control Structures Inspection and the Masonry Wall Inspection. This program implements provisions of the Maintenance Rule, 10 CFR 50.65, that relate to structures, masonry walls, and water control structures. Concrete, masonry walls and other structural components that perform a fire barrier intended function are also managed by the Fire Protection Program.

18.1.40 Water Control Structures Inspection

The Water Control Structures Inspection, implemented as part of the Structures Monitoring Program, consists of inspection activities to detect age-related degradation. The Water Control Structures Inspection ensures the structural integrity and operational adequacy of the Intake Structure, Forebay, Service Water Discharge Structure, and in-scope structural components within the structures.

18.1.41 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program consists of inspections of the internal surfaces of aluminum, copper alloy (including copper alloy > 15% zinc), stainless steel, and steel (including gray cast iron) components exposed to air, condensation, diesel exhaust, lubricating oil or moist air; and, external cooling coil surfaces.

The program manages loss of material and cracking; loss of material due to wear, hardening, and loss of strength of non-metallic, flexible (elastomeric) components; and reduction in heat transfer of cooling coil tubes and fins.

When required by the ASME Code, inspections are conducted in accordance with the applicable code requirements. In the absence of applicable code requirements, visual inspections are performed of metallic and polymeric component surfaces using plant-specific procedures implemented by inspectors qualified through plant-specific programs. The inspections are augmented to include physical manipulation of non-metallic, flexible (elastomeric) components to detect hardening or loss of strength. The sample population for physical manipulation is 10 percent of available surface area, including known suspect locations.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program includes opportunistic inspections, when components are opened for maintenance, repair, or surveillance to ensure that the existing environmental conditions are not causing material degradation that could result in a loss of component intended function during the period of extended operation. 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 material, environment, and aging effect combination) or a maximum of 25 components per population is inspected. Where practical, the inspection includes a representative sample of the system population and focuses on the bounding or lead components most susceptible to aging because of time in service and severity of the operating conditions. This minimum sample size does not override the opportunistic basis of this AMP.

The following table provides details regarding the parameters monitored and the inspection methods for the various aging effects and aging mechanisms that could affect components within the scope of the AMP.

| Parameters Monitored or Inspected And Aging Effect for Specific Component | | | |
|--|------------------------|-----------------------------------|---|
| Aging Effect | Aging Mechanism | Parameter Monitored | Inspection Method ⁽¹⁾ |
| Loss of Material | Crevice Corrosion | Surface Condition, Wall Thickness | Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) |
| Loss of Material | Galvanic Corrosion | Surface Condition, Wall Thickness | Visual (VT-3 or equivalent) and/or Volumetric (RT or UT) |
| Loss of Material | General Corrosion | Surface Condition, Wall Thickness | Visual (VT-3 or equivalent) and/or Volumetric (RT or UT) |
| Loss of Material | MIC | Surface Condition, Wall Thickness | Visual (VT-3 or equivalent) and/or Volumetric (RT or UT) |
| Loss of Material | Pitting Corrosion | Surface Condition, Wall Thickness | Visual (VT-1 or equivalent) and/or Volumetric (RT or UT) |
| Loss of Material | Erosion | Surface Condition, Wall Thickness | Visual (VT-3 or equivalent) and/or Volumetric (RT or UT) |
| Reduction of Heat Transfer | Fouling | Tube Fouling | Visual (VT-3 or equivalent) or Enhanced VT-1 for CASS |
| Cracking | SCC or Cyclic Loading | Surface Condition, Cracks | Enhanced Visual (EVT-1 or equivalent) or Surface Examination (magnetic particle, liquid penetrant, or Volumetric (RT or UT) |

⁽¹⁾ When required by the ASME Code, inspections are conducted in accordance with the applicable code requirements. In the absence of applicable code requirements, visual inspections are performed of metallic and polymeric component surfaces using plant-specific procedures implemented by inspectors qualified through plant-specific programs.

18.1.42 Nuclear Safety-Related Coatings Program

The Nuclear Safety-Related Protective Coatings Program monitors the performance of Service Level 1 coatings inside containment through periodic coating examinations, condition assessments and remedial actions, including repair or testing. The Nuclear Safety-Related Protective Coatings Program defines roles, responsibilities, controls and deliverables for monitoring the condition of coatings in containment. This program also ensures that the Design Basis Accident (DBA) analysis limits with regard to debris loading from failed coatings will not be exceeded for the Emergency Core Cooling Systems (ECCS) suction strainers.

18.1.43 Shield Building Monitoring Program

The Shield Building Monitoring Program is a prevention and condition-monitoring program for DBNPS. The program consists of inspections of the Shield Building Wall concrete and

reinforcing steel (rebar). The inspections conducted as part of the Shield Building Monitoring Program supplement the inspections conducted as part of the Structures Monitoring Program.

The program monitors for cracking, change of material properties and loss of material of concrete. The program also monitors for corrosion of the concrete rebar. As a preventive action of this program, the Shield Building Wall, Shield Building Dome and Shield Building Emergency Air Lock Enclosure wall exterior concrete coatings are inspected at a five-year interval for evidence of loss of effectiveness. Also, the Shield Building Wall, Shield Building Dome and Shield Building Emergency Air Lock Enclosure wall exterior concrete coatings will be reapplied at a fifteen-year interval.

Visual inspections are performed on rebar (when exposed), coatings, core bore and core bore sample surfaces in accordance with an implementing procedure by inspectors qualified as described in Chapter 7 of American Concrete Institute (ACI) Report ACI 349.3R, *Evaluation of Existing Nuclear Safety-Related Concrete Structures* [Reference 32]. The quantitative acceptance criteria for coatings from Chapter 5, Sections 5.1.4 and 5.2.4, of ACI Report 349.3R are used.

The core bore visual inspections are performed on a representative sample of Shield Building Wall structural subcomponents by inspection of the internal surfaces of core bores. The locations for the inspections were chosen from the core bores that have been installed in the subcomponents of the Shield Building Wall, including core bores installed to identify changes in the limits of cracking in areas with previously identified crack propagation. The representative sample size included 28 core bore inspection locations in the subcomponent population (defined as Shield Building Wall subcomponents having the same material, environment, and aging effect combination). The 28 core bore location distribution was chosen to include core bore inspections in 8 of the 10 flute shoulders with a high prevalence of event-driven laminar cracking (Shoulders 4-13). This distribution also covered shell sections above elevation 780 feet with 4 core bores (2 pairs), and each Main Steam Line penetration area with one core bore. As the Shield Building laminar cracking is being repaired, the core bores that fall within the repaired areas are removed from the visual inspection program (not replaced by other bores).

The Shield Building Monitoring Program includes periodic scheduled inspections to ensure that the existing environmental conditions are not causing material degradation that could result in loss of Shield Building intended functions during the period of extended operation.

The Shield Building Monitoring Program also included the performance of random Impulse Response (IR) mapping. IR mapping was performed on eight 100 square foot areas; four areas were performed in 2016, and four areas in 2018. Two of these grids were in areas away from existing core bores but in known crack areas to monitor any changes in the leading edges. Two of these grids were in areas not known to contain laminar cracking and away from existing core bores to establish cracking has not expanded into these areas. The locations for inspection by IR were chosen based on a sample of the exposed exterior of the Shield Building and were conducted to identify changes in the limits of cracking outside the areas inspected by core bores.

Additionally, IR mapping is used to supplement visual inspections at areas of identified propagation in leading edge core bores. In these cases, IR mapping is completed on a minimum area of 100 square feet in the vicinity of the core bore to provide a relative indication of the extent of cracking propagation for condition monitoring. IR mapping is performed in accordance with vendor procedures.

Implementation of this program ensures that the intended functions of the Shield Building and Shield Building Emergency Air Lock Enclosure are maintained during the period of extended operation.

18.1.44 Service Level III Coatings and Linings Monitoring Program

The Service Level III Coatings and Linings Monitoring Program manages loss of coating integrity due to blistering, cracking, flaking, peeling, delamination or physical damage of all Service Level III coatings and linings on the internal surfaces of mechanical fluid systems within the scope of license renewal. This program ensures that degraded coatings do not result in loss of intended function due to unanticipated or accelerated corrosion or flow blockage of mechanical components within the scope of license renewal.

The program is a condition monitoring program which consists of visual inspections of the in-scope Service Level III coatings and linings. For coated surfaces determined to not meet the acceptance criteria due to peeling, delamination or blistering, adhesion testing is performed where physically possible (i.e., sufficient room to conduct testing). The testing consists of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in Regulatory Guide 1.54, *Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants* [Reference 33]. The program follows the guidelines of ASTM D7167-05, *Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant* [Reference 34], and EPRI 1019157, *Guideline on Nuclear Safety Related Coatings Revision 2* [Reference 35], for monitoring the performance of in-scope coatings and linings, including training and qualification guidance for coatings inspectors. The Service Level III Coatings and Linings Monitoring Program will be implemented via baseline inspections prior to the end of the twenty-first refueling outage, followed by subsequent periodic inspections on an interval based on baseline inspection results.

18.1.45 References to Section 18.1

1. NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995.
2. NEI 94-01, "Industry Guidance for Implementing Performance-Based Options of 10 CFR Part 50 Appendix J," Revision 0.
3. NRC License Renewal Interim Staff Guidance (LR-ISG) LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," November 22, 2013
4. Electric Power Research Institute (EPRI) Report TR-104213, "Bolted Joint Maintenance and Applications Guide," December 1995.
5. Electric Power Research Institute (EPRI) Report TR-111472, "Assembling Bolted Connections Using Spiral Wound Gaskets," August 1999.
6. NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," March 17, 1988.
7. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," July 1980.
8. American National Standards Institute (ANSI) B30.2, "Overhead and Gantry Cranes," 1976.
9. American National Standards Institute (ANSI) B30.11, "Monorail Systems and Underhung Cranes," 1980.
10. American National Standards Institute (ANSI) B30.16, "Overhead Hoists (Underhung)," 1981.
11. American National Standards Institute (ANSI) B30.22, "Articulating Boom Cranes," 2010.
12. NRC Division of Operating Reactors (DOR) Guidelines, "Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors," November 1979.
13. NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," Revision 1.
14. NRC Regulatory Guide 1.89, "Environmental Qualification of Certain Electrical Equipment Important to Safety for Nuclear Power Plants," Revision 1.
15. NRC Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 3.
16. NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," February 1995.

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17. Electric Power Research Institute (EPRI) Report 1012017 (MRP-47), "Materials Reliability Program: Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application," Revision 1, September 2005.
18. NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," March 1998.
19. NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999.
20. NUREG/CR-6909 "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials," February 2007
21. NFPA 25, "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," 2011 Edition
22. NRC Generic Letter 89-08, "Erosion/Corrosion – Induced Pipe Wall Thinning," May 1989.
23. Electric Power Research Institute (EPRI) Report 1011838, "Recommendations for An Effective Flow Accelerated Corrosion Program (NSAC-202L-R4)," November 2013.
24. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Case N 770-1, Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities, Section XI, Division 1, December 25, 2009.
25. American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Case N-729-1, "Alternative Examination Requirements for PWR Reactor Vessel Upper Heads with Nozzles Having Pressure-Retaining Partial-Penetration Welds, Section XI, Division 1", March 28, 2006
26. NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," July 1989.
27. Electric Power Research Institute (EPRI) Report 1022863, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," December 2011.
28. Electric Power Research Institute (EPRI) Report 1016609, "Materials Reliability Program: Inspection Standard for PWR Internals (MRP-228)," July 2009.
29. NRC Regulatory Guide 1.65, "Material and Inspection for Reactor Vessel Closure Studs," October 1973.
30. Electric Power Research Institute (EPRI) Report 1011955, "Materials Reliability Program: Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146)," June 2005.
31. Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines," Revision 3, January 2011.

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32. American Concrete Institute (ACI) Report ACI 349.3R-02, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," June 17, 2002.
33. NRC Regulatory Guide 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," Revision 2, October 2010.
34. ASTM D7167-05, "Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant," July 2005.
35. Electric Power Research Institute (EPRI) Report 1019157, "Plant Support Engineering: Guideline on Nuclear Safety-Related Coatings," Revision 2, December 2009.
36. AREVA Document ANP-3339, Davis-Besse Unit 1 Reactor Vessel Material Surveillance Program: Analysis of Capsule TE1-C, Revision 0, December 2014.

18.2 TIME-LIMITED AGING ANALYSES (TLAAs)

18.2.1 Introduction

Time-limited aging analyses (TLAAs) are defined in 10 CFR 54.3(a) as those licensee calculations and analyses that:

1. Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a);
2. Consider the effects of aging;
3. Involve time-limited assumptions defined by the current operating term, for example, 40 years;
4. Were determined to be relevant by the licensee in making a safety determination;
5. Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and
6. Are contained or incorporated by reference in the current licensing basis.

The TLAAs (i.e., each calculation or analysis) that meet all six aspects above, were evaluated in accordance with 10 CFR 54.21(c)(1) to demonstrate that:

- (i) The analyses remain valid for the period of extended operation, or
- (ii) The analyses have been projected to the end of the period of extended operation, or
- (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

This Section provides a summary of the TLAAs identified in the DBNPS License Renewal Application, and includes the following topics:

- Reactor Vessel Neutron Embrittlement (Section 18.2.2)
- Metal Fatigue (Section 18.2.3)
- Environmental Qualification of Electrical Equipment (Section 18.2.4)
- Containment Fatigue Analyses (Section 18.2.5)
- Inservice Inspection – Fracture Mechanics Analyses (Section 18.2.6)
- Other Plant-Specific Time-Limited Aging Analyses (Section 18.2.7)
- Reactor Vessel Neutron Embrittlement (Section 18.2.8)
- References to Section 18.2 (Section 18.2.9)

18.2.2 Reactor Vessel Neutron Embrittlement

Neutron embrittlement is the term used to describe changes in mechanical properties of reactor vessel materials that result from exposure to fast neutron flux, energy greater than 1.0 mega-electron volts ($E > 1.0$ MeV), within the vicinity of the reactor core called the beltline region. The most pronounced material change is a reduction in fracture toughness. As fracture toughness decreases with cumulative fast neutron exposure, the material's resistance to crack propagation decreases. The rate of neutron exposure is neutron flux ($n/cm^2/sec$) and the cumulative neutron exposure over time is neutron fluence (n/cm^2).

Fracture toughness is also dependent on temperature. The reference temperature for nil-ductility transition (RT_{NDT}) is the temperature above which the material behaves in a ductile manner and below which the material behaves in a brittle manner. As fluence increases, RT_{NDT} increases; this means higher temperatures are required for the material to continue to act in a ductile manner. Determining the projected reduction in fracture toughness as a function of fluence affects several analyses used to support the operation of DBNPS:

- Neutron Fluence (Section 18.2.2.1)
- Upper Shelf Energy (Section 18.2.2.2)
- Pressurized Thermal Shock (Section 18.2.2.3)
- Pressure-Temperature Limits (Section 18.2.2.4)
- Low-Temperature Overpressure Protection Limits (Section 18.2.2.5)
- Intergranular Separation – Underclad Cracking (Section 18.2.2.6)
- Reduction in Fracture Toughness of Reactor Vessel Internals (Section 18.2.2.7)

Requirements associated with fracture toughness and pressure-temperature limits for the reactor coolant pressure boundary are contained in Appendices G and H of 10 CFR 50.

18.2.2.1 Neutron Fluence

Fluence Projection

The fluence analysis methodology from BAW-2241P-A, *Fluence and Uncertainty Methodologies* [Reference 1], was used to calculate the fast neutron fluence ($E > 1.0$ MeV) of the reactor vessel welds and forgings of interest. The fast neutron fluence at each location was calculated in accordance with the requirements of NRC Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Vessel Neutron Fluence* [Reference 2].

Fluence results were calculated for Cycles 13-14 irradiation using a computer model that extends from below the core to the vessel mating surface. The sum of the End-of-Cycle (EOC) 12 and Cycles 13-14 fluence results in the EOC 14 cumulative fluence. This data was benchmarked against cavity dosimetry data for Cycles 13-14. To extrapolate the fluence values to end of life, Cycle 15 design information was utilized to develop flux projections at each location. These Cycle 15 flux values were used to extrapolate the EOC 14 fluence to 52 effective full power years (EFPY) assuming 100% power at 2,817 MWt and a partial low leakage

core design whereby High Thermal Performance fuel assemblies (a total of 12) were introduced on the periphery.

Beltline Evaluation

10 CFR 50.61 defines the reactor vessel beltline as the region of the reactor vessel (shell materials including welds, heat affected zones, and plates or forgings) that directly surrounds the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most controlling material with regard to radiation damage.

The DBNPS beltline for the first 40 years of operation includes the nozzle belt forging (ADB 203), the nozzle belt forging to upper shell forging circumferential weld (WF-232/233), the upper shell forging (AKJ 233), the upper shell forging to lower shell forging circumferential weld (WF-182-1), and the lower shell forging (BCC 241).

For the period of extended operation, the beltline will include all items with 52 EFPY surface fluence greater than $1.0E+17$ n/cm² ($E > 1$ MeV). The limiting weld with regard to upper-shelf energy (USE), adjusted reference temperature (ART), and reference temperature for pressurized thermal shock (RT_{PTS}) is the upper shell to lower shell weld WF-182-1, as is the case for the first 40 years of operation. The limiting forging with regard to ART and RT_{PTS} is the lower shell forging BCC 241, as is the case at 40 years. Both of these materials are included in the Reactor Vessel Surveillance Program and no additional materials are required for irradiation and testing.

A neutron fluence analysis valid for 52 EFPY has been prepared for the reactor vessel beltline materials to bound the projected value of 50.3 EFPY for 60 years of operation. Therefore, the neutron fluence analysis has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.2.2 Upper-Shelf Energy (USE)

10 CFR 50 Appendix G requires the USE for the reactor vessel beltline materials to be no less than 50 ft-lb at all times during plant operation, including the effects of neutron radiation. If USE cannot be shown to remain above this limit, then an equivalent margins analysis (EMA) must be performed to show that the margins of safety against fracture are equivalent to those required by Appendix G of ASME Section XI.

Reactor Vessel Beltline Forgings

For license renewal, the initial USE values are projected to 52 EFPY using Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Materials* [Reference 3], Position 1.2. Position 2.2, "Use of Surveillance Data," was also used for the lower shell forging BCC 241. The 52 EFPY USE values for the reactor vessel beltline forgings are above 50 ft-lb, and therefore an equivalent margins analysis is not required.

Reactor Vessel Beltline Welds

The 52 EFPY USE values for the reactor vessel beltline welds were conservatively assumed to be below 50 ft-lb at 52 EFPY and therefore, required qualification by equivalent margins analysis. Equivalent margins analyses performed for the reactor vessel beltline welds

demonstrated that the welds satisfied the ASME Code requirements of Appendix K for ductile flow extensions and tensile stability at 52 EFPY.

Reactor vessel USE and the equivalent margin analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.2.3 Pressurized Thermal Shock

10 CFR 50.61(a)(2) defines pressurized thermal shock (PTS) as an event or transient in pressurized water reactors (PWRs) causing severe overcooling (thermal shock) concurrent with or followed by significant pressure in the reactor vessel. 10 CFR 50.61(b)(2) defines screening criteria for embrittlement of reactor vessel materials in PWRs, and required actions if the screening criteria are exceeded. The screening criteria are based on the RT_{PTS} . The screening criterion for circumferential welds is 300°F maximum and the screening criterion for forgings is 270°F maximum. If the projected RT_{PTS} values remain below the applicable screening temperature, then no corrective actions are required.

For license renewal, a 52 EFPY RT_{PTS} evaluation was performed for the reactor vessel beltline materials. In accordance with 10 CFR 50.61, the RT_{PTS} values were calculated by adding the initial RT_{NDT} to the predicted radiation-induced ΔRT_{NDT} including a margin term to cover the uncertainties, as prescribed by Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Materials* [Reference 3]. The predicted radiation induced ΔRT_{NDT} was calculated using the 52 EFPY neutron fluence at the clad-low alloy steel interface. Initial RT_{NDT} and margins for welds WF-182-1 and WF-232 (Nozzle Belt Forging to Upper Shell Forging Circumferential Weld) were obtained from BAW-2308, *Initial RT_{NDT} of Linde 80 Weld Materials* [Reference 4], Revision 1-A.

All RT_{PTS} values are below the screening criteria at 60 years. The upper to lower shell circumferential weld (WF-182-1) is the limiting material with respect to RT_{PTS} .

Reactor vessel RT_{PTS} has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.2.4 Pressure-Temperature Limits

10 CFR 50 Appendix G requires the establishment of pressure-temperature (P-T) limits for material fracture toughness requirements of the reactor coolant pressure boundary materials. 10 CFR 50, Appendix G mandates the use of the ASME Section III, Appendix G to determine the stresses and fracture toughness at locations within the reactor coolant pressure boundary.

The DBNPS *Pressure and Temperature Limits Report (PTLR)* [Reference 5], provides pressure-temperature (P-T) limits for the DBNPS reactor coolant pressure boundary (RCPB) that are valid to 32 EFPY. The P-T limits were generated consistent with the requirements of 10 CFR 50 Appendix G and Regulatory Guide 1.99, Revision 2 [Reference 3], using the methods described in Topical Report BAW-10046A, *Method of Compliance with Fracture Toughness and Operational Requirements of 10CFR50, Appendix G* [Reference 6], Revision 2, and ASME Section XI, Appendix G, as modified by the alternative rules provided in ASME Code Case N-588 for flaws in circumferential welds and ASME Code Case N-640 for use of the K_{IC} reference fracture toughness curve from Section XI, Appendix A. The RT_{NDT} values of the reactor vessel beltline welds (Linde 80 welds) were determined using methods provided in approved Topical Report BAW-2308, *Initial RT_{NDT} of Linde 80 Weld Materials*, Revisions 1-A [Reference 4] and 2-A [Reference 7] rather than the methodology described within Topical Report BAW-10046A,

Revision 2, which is used to evaluate the other beltline components. The NRC required licensees to obtain an exemption [Reference 8] from 10 CFR 50.61 and 10 CFR 50, Appendix G to use the alternate initial RT_{NDT} values provided in BAW-2308 Revisions 1-A and 2-A. The required exemption was granted by the NRC in a letter dated December 14, 2010 [Reference 9].

The current P-T limits, generated consistent with the requirements of 10 CFR 50 Appendix G and Regulatory Guide 1.99 [Reference 3], are valid until 32 EFPY. A revised pressure and temperature limits report (PTLR) will be submitted to the NRC, in accordance with Technical Specification 5.6.4, before DBNPS operates beyond 32 EFPY in accordance with the requirements of 10 CFR 50, Appendix G. The revised P-T limits for the period of extended operation will be based on an evaluation of the effects of neutron embrittlement for the 60-year beltline materials, the stresses in the closure head region of the reactor vessel (subject to significant stresses due mechanical loads resulting from bolt preload) and the stresses in the reactor vessel outlet nozzles (largest nozzles in the RCS and the inside corners of the nozzles are subjected to high local stresses produced by pressure). The 60-year reactor vessel beltline materials are those listed below, plus any other that could experience 52 EFPY inside surface fluence greater than $1.0E17$ n/cm²:

- Nozzle Belt Forging (ADB 203)
- Upper Shell Forging (AKJ 233)
- Lower Shell Forging (BCC 241)
- Nozzle Belt Forging to Upper Shell Forging Circumferential Weld (Inside 9%) (WF-232) / (Outside 91%) (WF-233)
- Upper Shell Forging to Lower Shell Forging Circumferential Weld (WF-182-1)
- Reactor Vessel Inlet Nozzle Forgings (BSS 270)
- Reactor Vessel Outlet Nozzle Forgings (ATS 239)
- Dutchman Forging (122Y384VA1)
- Nozzle Belt Forging to Bottom of Reactor Vessel Inlet Nozzle Forging Weld (WF-233 / WF-232)
- Nozzle Belt Forging to Bottom of Reactor Vessel Outlet Nozzle Forging Weld (WF-233)
- Lower Shell Forging to Dutchman Forging Circumferential Weld (Inside 12%) (WF-232) / (Outside 88%) (WF-233)

Reactor vessel P-T limits will be managed, as part of the Reactor Vessel Surveillance Program [UFSAR Section 18.1.35] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.2.5 Low-Temperature Overpressure Protection Limits

Appendix G of ASME Section XI establishes procedures and limits for Reactor Coolant System pressure and temperature primarily for low temperature conditions to provide protection against non-ductile failure of the reactor vessel.

Low-temperature overpressure protection (LTOP) is provided in two ways at DBNPS.

1. Administrative controls are used to assure protection within the existing pressure-temperature limits when the pressurizer power-operated relief valve and the safety valves are no longer providing overpressure protection.
2. A relief valve in the Decay Heat Removal System suction piping is placed into service when the Reactor Coolant System temperature is below 280°F.

The current Technical Specifications for LTOP are valid to 32 EFPY. These Technical Specifications used an improved methodology to calculate LTOP limits in accordance with generically approved topical report AREVA NP Document BAW-10046A, *Method of Compliance with Fracture Toughness and Operational Requirements of 10CFR50, Appendix G* [Reference 6]. Maintaining the LTOP limits in accordance with Appendix G of ASME Section XI, as required by Appendix G of 10 CFR 50, assures that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

LTOP limits will be managed, as part of the Reactor Vessel Surveillance Program [UFSAR Section 18.1.35], for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.2.6 Intergranular Separation – Underclad Cracking

Underclad cracking refers to intergranular separations in the heat affected zones of low alloy base metal under austenitic stainless steel cladding in SA-508, Class 2 reactor vessel forgings manufactured to a coarse grain practice, and clad by high-heat-input submerged arc processes. AREVA NP Document BAW-10013-A, *Study of Intergranular Separations in Low-Alloy Steel Heat-Affected Zones under Austenitic Stainless Steel Weld Cladding* [Reference 10], contains a fracture mechanics analysis that demonstrates the critical crack size required to initiate fast fracture is several orders of magnitude greater than the assumed maximum flaw size plus predicted flaw growth due to design fatigue cycles. The flaw growth analysis was performed for a 40 year cyclic loading, and an end-of-life assessment of radiation embrittlement (i.e., fluence at 32 EFPY) was used to determine fracture toughness properties. The report concluded that the intergranular separations found in B&W vessels would not lead to vessel failure. This report was accepted by the Atomic Energy Commission.

Evaluation of intergranular separations for the DBNPS SA-508 Class 2 forgings was performed for 60 years using the current fracture toughness information, applied stress intensity factor solutions, and fatigue crack growth correlations for SA-508 Class 2 material. The analysis was applied to two relevant regions of the reactor vessel: the beltline and the nozzle belt. Both axial and circumferential oriented flaws were considered in the evaluation; however, the detailed flaw evaluation was only performed for the bounding axially-oriented flaws. The fatigue crack growth analysis considered the normal and upset condition transients with the associated 60-year projected cycles for the period of extended operation. The analysis determined that the postulated underclad cracks in the reactor vessel are acceptable through the period of extended operation.

The reactor vessel closure head/head flange was replaced in the Fall of 2011. This replacement head was fabricated using SA-508 Class 3 material, which is not susceptible to the subject intergranular separations. Therefore, this replacement closure head/head flange is not considered in the underclad cracking evaluation.

Reactor vessel underclad cracking TLAAAs have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.2.7 Reduction in Fracture Toughness of Reactor Vessel Internals

Reduction in fracture toughness of (stainless steel) reactor vessel internals is an aging effect caused by exposure to neutron irradiation. Prolonged exposure to high-energy neutrons results in changes to the mechanical properties, such as an increase in tensile and yield strength, and decreases in ductility and fracture toughness. The extent of reduction in fracture toughness is a function of the material, irradiation temperature, and neutron fluence.

UFSAR Appendix 4A describes the detailed stress analysis of the reactor vessel internals under accident conditions for the current term of operation. The results of this analysis show that although there is some deflection of the internals, the reactor vessel internals will not fail because the stresses are within established limits.

Evaluation of the impact of the measurement uncertainty recapture (MUR) power uprate on the structural integrity of the reactor vessel internals components concluded that the temperature changes due to the power uprate are bounded by those used in the existing analyses. As part of MUR uprate, the company provided the following commitment:

“As appropriate, the company commits to incorporate recommendations from EPRI's MRP inspection guidelines into the reactor vessel internals program at Davis-Besse Nuclear Power Station, Unit, No. 1.”

Integrity of reactor vessel internals will be managed, as part of the PWR Reactor Vessel Internals Program [UFSAR Section 18.1.32], for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3 Metal Fatigue

The following sections summarize the analyses associated with metal fatigue of fluid systems:

- Class 1 Code Fatigue Requirements (Section 18.2.3.1)
- Class 1 Fatigue Evaluations (Section 18.2.3.2)
- Non-Class 1 Fatigue Evaluations (Section 18.2.3.3)
- Generic Industry Issues on Fatigue (Section 18.2.3.4)

18.2.3.1 Class 1 Code Fatigue Requirements

The ASME Class 1 components for DBNPS include the reactor vessel, reactor coolant pressure boundary components, and the once through steam generators. The specific codes and standards to which systems, structures, and components were designed are listed in UFSAR Table 3.2-2, “Code Classification.”

Cumulative usage factors for the Class 1 components are calculated based on normal and upset design transient definitions contained in the component design specifications. The design transients used to generate cumulative usage factors for Class 1 components are reported in UFSAR Table 5.1-8, "Transient Cycles Design Life." DBNPS Technical Specification 5.5.5 provides controls to track the UFSAR Section 5 cyclic and transient occurrences to ensure that components are maintained within design limits.

Fatigue of Class 1 components is managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16]. This program tracks the occurrence of plant transients that affect fatigue. The number of design cycles originally considered in the design fatigue analyses is not a design limit. The design limit for fatigue is the ASME Code allowable cumulative usage factor of 1.0. The fatigue usage for a component is normally the result of several different thermal transients, coupled with mechanical loads. Exceeding the design cycles for one or more transients does not necessarily imply that fatigue usage will exceed the allowable limit.

18.2.3.1.1 ASME Section III

The primary code governing design and construction of the Class 1 systems and components is the ASME Boiler and Pressure Vessel Code, Section III. The ASME Code requires evaluation of transient thermal and mechanical load cycles and determination of fatigue usage for Class 1 components.

18.2.3.1.2 B31.7 Piping Code

The DBNPS reactor coolant system piping, as well as reactor coolant pressure boundary piping in other systems, was designed to American National Standards Institute (ANSI) B31.7 Draft, February 1968 with Errata, June 1968 and also meets the design requirements of ANSI B31.7, 1969 Edition. The ANSI B31.7 Piping Code requires evaluation of transient thermal and mechanical load cycles and determination of fatigue usage for Class 1 piping. The reactor head vent and other piping designated as quality group A, B, or C is designed to ASME Section III, 1971 Edition, Class 1, 2 or 3 respectively. DBNPS has no Class 1 piping designed to ANSI B31.1.

18.2.3.1.3 Design Cycles

ASME Class 1 components are designed to withstand the effects of cyclic loads due to temperature and pressure changes in the reactor system. These cyclic loads are introduced by normal unit load transients, reactor trips, startup and shutdown operations, and earthquakes. The 14 original design transients for the Reactor Coolant System (RCS) are found in UFSAR Table 5.1-8, "Transient Cycles Design Life." Over the life of the plant, additional transients have been identified, including analyzed transients for new components and non-RCS components. The design cycles that are significant contributors to fatigue usage are included in the Fatigue Monitoring Program [UFSAR Section 18.1.16].

18.2.3.1.4 Reactor Coolant Piping

The reactor coolant piping connects the major components of the Reactor Coolant System, including the reactor vessel, the steam generators and the reactor coolant pumps. The reactor coolant piping has welded connections for pressure taps, temperature elements, vents, drains, decay heat removal, and emergency core cooling high-pressure injection water.

A thermal sleeve is provided in the high-pressure injection connection to the reactor coolant inlet piping. The analysis of the high-pressure injection nozzles determined that high-pressure injection flow tests had negligible effect on the high-pressure injection nozzles, but a significant effect on the normal makeup nozzle. The cumulative usage factor (CUF) for the normal makeup nozzle was calculated to be 0.558 after 40 flow tests; 0.513 usage due to the 40 flow tests and 0.045 usage due to all other transients. Projections of cycles for 60 years implies that the 40 design cycles will be reached in year 51, with 48 cycles occurring by year 60. Projecting the CUF to a 60-year number with 50 tests, gives a CUF of 0.686 ($0.045 + 50/40 * 0.513$), which implies the nozzles will still be acceptable. However, DBNPS monitors these cycles and will ensure action is taken before the analyzed number of cycles is reached. Because these nozzles may be reanalyzed for other reasons, DBNPS will manage fatigue of these nozzles for the period of extended operation. DBNPS replaced the nozzle safe ends and thermal sleeves prior to reaching the period of extended operation.

The effects of fatigue on the reactor coolant piping will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2 Class 1 Fatigue Evaluations

The Fatigue Monitoring Program [UFSAR Section 18.1.16] monitors the number of plant transient cycles to ensure that action is taken before the number of design cycles is exceeded. As such, the effects of aging due to fatigue are managed for the period of extended operation for the Class 1 piping and components.

Specific evaluations for Class 1 components are discussed below.

18.2.3.2.1 Reactor Vessel Internals Bolts

Although the reactor vessel internals are designed to meet the stress requirements of ASME Section III, they are not code components. Consequently, a fatigue analysis of the reactor vessel internals was not required and was not performed as part of the original design.

The company has replaced the majority of the stainless steel, Alloy A-286, bolts for the reactor vessel internals with Alloy X-750 HTH bolts at DBNPS. The replacement bolts were designed to ASME Section III, and are provided with fatigue analyses. The company has not replaced the upper thermal shield bolts, flow distributor bolts, or guide block bolts at DBNPS. Design cumulative usage factors for the reactor vessel internals bolts are based on design cycles.

The effects of fatigue on the reactor vessel internals bolts will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.2 Reactor Vessel Internals and Incore Instrument Nozzles Flow Induced Vibration

The reactor vessel internals were analyzed for flow induced vibration. The classic endurance limit approach to design of components subject to flow-induced vibration was used, except for the re-designed surveillance capsule holder tubes. The classic endurance limit approach is based on the observation that a fatigue curve becomes approximately asymptotic to a given value of stress (the endurance limit) for large numbers of cycles. A component can be designed for infinite life by maintaining the actual peak stresses below the endurance limit.

For the DBNPS reactor vessel internals, the ASME Code fatigue curve was extended to $1\text{E}+12$ cycles (the upper bound on the number of cycles for a 40-year design life). The resulting stress value of 20,400 psi was reduced to 18,000 psi as the endurance limit. For 60-years of operation, it follows that $1.5\text{E}+12$ would bound the expected loading cycles. The extrapolated fatigue curve at $1.5\text{E}+12$ cycles is approximately 20,200 psi, still above the 18,000 psi that was used as the endurance limit. Therefore, the flow induced vibration analysis of the reactor vessel internals and the incore instrument nozzles remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The re-designed surveillance capsule holder tubes (re-designed holder tubes are installed at DBNPS) were analyzed for fatigue due to flow induced vibration. The resulting cumulative usage factor (CUF) is 0.00042. To project the flow induced vibration analysis from 40 years to 60 years of operation, 0.00042 was multiplied by 1.5 resulting in a CUF of 0.00063. The 60-year projected CUF is below the Code design limit of 1.0. Therefore, the surveillance capsule holder tubes flow induced vibration analysis has been satisfactorily projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.3.2.3 Control Rod Drive Housings

The control rod drive housings are designed to ASME Section III and are analyzed for fatigue. The fatigue analyses for the control rod drive housings are based on the design transients, and the resulting cumulative usage factors are all less than 1.0.

The effects of fatigue on the control rod drive housings will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.4 Reactor Coolant Pump Casings Fatigue

The reactor coolant pump casings are designed to ASME Section III and are analyzed for fatigue. The fatigue analyses for the reactor coolant pump casings are based on design transients, and the resulting cumulative usage factors are all less than 1.0.

The effects of fatigue on the reactor coolant pump casings will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.5 Pressurizer Fatigue

The pressurizer is designed to ASME Section III and is analyzed for fatigue. Design cumulative usage factors for the limiting pressurizer locations, including the surge nozzle, were analyzed based on design transients and are all less than 1.0.

The effects of fatigue on the pressurizer will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.6 Reactor Vessel

The reactor is designed as a Class A vessel in accordance with the ASME Code, Section III, 1968 Edition through Summer 1968 Addenda. A stress analysis of the entire vessel was conducted under both steady-state and transient operations. The result is a complete

evaluation of both primary and secondary stresses and the fatigue life of the entire vessel. The reactor vessel was analyzed for fatigue by the original equipment manufacturer.

The cumulative usage factors for the limiting reactor vessel assembly locations were calculated to be less than 1.0 based on the design transients. The number of occurrences of design transients is tracked by the Fatigue Monitoring Program [UFSAR Section 18.1.16] to ensure that action is taken before the analyzed numbers of transients are reached. As such, the effects of aging due to fatigue are managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.7 Once Through Steam Generators

The primary (tube) and secondary (shell) sides of the once through steam generators are designed to ASME Section III, 2001 Edition with 2003 Addenda. The steam generators were analyzed for fatigue by the original equipment manufacturer. The cumulative usage factors for the limiting primary and secondary side steam generators locations were calculated based on design transients, and are all less than 1.0. The number of occurrences of design transients is tracked by the Fatigue Monitoring Program [UFSAR Section 18.1.16] to ensure that action is taken before the design cycles are reached. As such, the effects of aging due to fatigue are managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.8 Class 1 Piping

The DBNPS reactor coolant system piping, as well as reactor coolant pressure boundary piping in other systems, was designed to American National Standards Institute (ANSI) B31.7 Draft, February 1968 with Errata, June 1968, and also meets the design requirements of ANSI B31.7, 1969 Edition. The B31.7 Piping Code requires evaluation of transient thermal and mechanical load cycles and determination of fatigue usage for Class 1 piping. The reactor head vent and other piping designated as quality group A, B, or C is designed to ASME Section III, 1971 Edition, Class 1, 2 or 3 respectively. Only quality group D piping is designed to ANSI B31.1.

A portion of the reactor coolant system hot leg piping was replaced in support of steam generator replacement in the spring of 2014. Applicable ASME Code of Construction for the replaced hot leg piping is Section III, 2001 Edition with 2003 Addenda.

The cumulative usage factors for the Class 1 piping were analyzed based on the design transients, and are all less than 1.0. The number of occurrences of design transients is tracked by the Fatigue Monitoring Program [UFSAR Section 18.1.16] to ensure that action is taken before the design cycles are reached. As such, the effects of aging due to fatigue are managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.3.2.9 High Energy Line Break (HELB) Postulations

UFSAR Section 3.6.2.2.1 indicates that the criteria given in Regulatory Guide 1.46 was used in determining the pipe break locations for pipe whip restraint design. This allows the elimination of potential break locations based on cumulative usage factors being less than 0.1, if other stress criteria are also met. The analyzed cycles that were used in the Class 1 HELB break location determinations were compared to the 60-year projected cycles. The comparison determined that the analyzed cycles bound the 60-year projected cycles. Therefore, the Class 1 HELB postulations remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.2.3.2.10 Class 1 Valves Fatigue

The ASME Code requires a fatigue evaluation for Class 1 valves greater than 4 inches diameter nominal pipe size or for valves less than or equal to 4 inches in nominal pipe size if specified by the owner's design specification. The DBNPS purchasing specifications did not require a fatigue analysis for Class 1 valves less than or equal to 4 inches in nominal pipe size. Therefore, only valves greater than 4 inches diameter nominal pipe size require a fatigue analysis. Piping and instrumentation diagrams (P&IDs) were reviewed to identify Class 1 valves of greater than 4 inches diameter nominal pipe size. There were 12 valves of greater than 4 inches diameter nominal pipe size that were identified as a result of this effort.

Fatigue analyses were prepared for the subject Class 1 valves in accordance with paragraph NB-3550 of ASME Code Section III, 1974 Edition with Addenda through the Summer of 1976 and were reconciled to the valve construction code year.

Since ASME Code fatigue analyses evaluate an explicit number and type of thermal and pressure transients that are postulated to envelope the number of occurrences possible during the design life of the plant, these fatigue analyses are time-limited aging analyses (TLAAs) and therefore, are required to be evaluated in accordance with 10 CFR 54.21(c)(1).

The cumulative usage factors calculated for the subject Class 1 valves are based on nuclear steam supply system design transients and, as shown in the table below, are less than 1.0. The number of occurrences of design transients is tracked by the Fatigue Monitoring Program [UFSAR Section 18.1.16] to ensure that action is taken before the design cycles are reached. Therefore, the effects of fatigue on Class 1 valves greater than 4 inches diameter nominal pipe size (NPS) will be managed for the period of extended operation by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii).

| Valve ID | Size (dia. NPS) & Type | Construction Code Year | Description | Maximum CUF |
|-----------------|---|---------------------------------------|---|------------------------|
| CF28 | 14 inch swing check | 1971 w/Addenda thru Winter 1972 | Core Flood – core flood tank discharge line stop check isolation valve | 0.02839 |
| CF29 | | | | |
| CF30 | | | | |
| CF31 | | | | |
| DH11 | 12 inch gate | 1968 Draft Pump & Valve | Reactor Coolant System to Decay Heat – containment isolation valve | 0.14594 |
| DH12 | | | | |
| DH21 | 8 inch gate | 1971 w/Addenda thru Winter 1972 | Reactor Coolant System to Decay Heat – containment isolation valve bypass line isolation valve | 0.02732 |
| DH23 | | | | |
| DH76 | 10 inch piston check | 1971 w/Addenda thru Winter 1972 | Low Pressure Injection to Reactor Coolant System – stop check isolation valve | 0.14099 |
| DH77 | | | | |
| DH1A | 10 inch gate | 1968 Draft Pump & Valve | Low Pressure Injection – outside containment isolation valve | 0.18261 |
| DH1B | | | | |

18.2.3.3 Non-Class 1 Fatigue Evaluations

The specific codes and standards to which systems and components important to safety were designed are listed in UFSAR Table 3.2.2, "Code Classification."

The non-Class 1 mechanical components susceptible to fatigue fit into the two major categories:

1. Piping and in-line components (tubing, piping, thermowells, valve bodies, etc.)

Non-class 1 components that are quality group B or C are largely designed and constructed to the ASME Code, but certain components are built to other codes including ANSI B31.1. The design of ASME Section III Code Class 2 and 3 piping systems incorporates a stress range reduction factor for determining acceptability of piping design with respect to thermal stresses. Piping systems designed to ANSI B31.1 also incorporate stress range reduction factors based upon the number of thermal cycles. 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. If fewer than 7,000 cycles are expected through the period of extended operation, then the fatigue analysis (stress range reduction factor) of record will remain valid through the period of extended operation.

2. Non-piping components (Major Components)

Fatigue need not be addressed for non-Class 1 vessels, heat exchangers, storage tanks, and pumps, unless these components were designed to ASME Section VIII Division 2 or ASME Section III, Subsection NC-3200.

Each of these categories is addressed below.

18.2.3.3.1 Non-Class 1 Piping and In-Line Components

Thermal cycles have been projected through 60 years of plant operation. These projections, applied to the non-Class 1 piping and in-line components, indicate that 7,000 thermal cycles will not be exceeded during 60 years of operation.

The analyses associated with fatigue of non-Class 1 piping and in-line components remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.2.3.3.2 Non-Class 1 Major Components

For those non-Class 1 non-piping components identified as possibly subject to fatigue, a review of component design codes was conducted to determine if fatigue analyses of the components were required. If no fatigue analysis was required, then no TLAA for fatigue exists.

While most Class 1 components are designed in accordance with ASME Section III, non-Class 1 pressure vessels, heat exchangers, tanks, and pumps are often designed in accordance with other industry codes and standards, reactor designer specifications, and architect engineer specifications. ASME Section III, Subsection NC-3200 and ASME Section VIII, Division 2 include fatigue design requirements, and include provisions for "exemption from fatigue," which is actually a simplified fatigue evaluation based on materials, configuration, temperature, and cycles. If cyclic loading and fatigue usage for a component could be significant, then ASME Section III, Subsection NC 3200 or ASME Section VIII, Division 2 are specified.

Due to conservatism in ASME Section III, Subsections NC-3100 and ND-3000 and ASME Section VIII, Division 1, detailed fatigue analyses are not required. Also, fatigue analyses are not required for ASME Section III, Subsection NC and ND pumps and storage tanks (less than 15 psig), or for other design codes (e.g., ASME Section VIII, Division 1, American Water Works Association, Manufacturer's Standardization Society, National Electrical Manufacturers Association).

There are no fatigue analyses, and therefore no TLAA, associated with the non-Class 1 non-piping components.

18.2.3.4 Generic Industry Issues on Fatigue

This section addresses the DBNPS fatigue TLAAs associated with NRC Bulletin 88-11, *Pressurizer Surge Line Thermal Stratification*, and with the effects of the primary coolant environment on fatigue life.

18.2.3.4.1 Pressurizer Surge Line Thermal Stratification

NRC Bulletin 88-11 required the re-evaluation of the cyclic fatigue of the pressurizer surge line. As part of the re-evaluation, the DBNPS plant heatup and cooldown transients were redefined. Other transients were modified to include thermal stratification and striping. The surge line piping and nozzles were analyzed for license renewal, considering the effects of the reactor coolant environment. See Section 18.2.3.4.2 for a discussion of the effects of the reactor coolant environment on fatigue.

18.2.3.4.2 Effects of the Reactor Coolant Environment on Fatigue

Industry test data indicates that certain environmental effects (such as temperature and dissolved oxygen content) in the primary systems of light water reactors could result in greater susceptibility to fatigue than would be predicted by fatigue analyses based on the ASME Section III design fatigue curves. The ASME design fatigue curves were based on laboratory tests in air and at low temperatures. Although the failure curves derived from laboratory tests were adjusted to account for effects such as data scatter, size effect, and surface finish, these adjustments may not be sufficient to account for actual plant operating environments.

No immediate NRC staff or licensee action is necessary to deal with the environmentally assisted fatigue issue. However, because metal fatigue effects increase with service life, environmentally assisted fatigue is evaluated for license renewal.

NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components* [Reference 11], identifies locations of interest for consideration of environmental effects in several types of nuclear plants. Section 5.3 of NUREG/CR 6260 reviewed the following locations for Babcock & Wilcox pressurized water reactors.

1. Reactor vessel shell and lower head; including the instrumentation nozzles
2. Reactor vessel inlet and outlet nozzles
3. Pressurizer surge line (including pressurizer surge nozzle and hot leg surge nozzle)
4. High pressure injection/makeup nozzle
5. Reactor vessel core flood nozzle
6. Decay heat removal Class 1 piping

Evaluations performed for the period of extended operation indicate that 40-year cumulative usage factors will not exceed 1.0; however an environmentally assisted fatigue adjustment is not applied for the initial 40 years of operation, consistent with the closure of Generic Safety Issue (GSI) 190, *Fatigue Evaluation of Metal Components for 60-year Plant Life*.

The effect of the reactor coolant environment on fatigue usage has been evaluated for the six locations identified in NUREG/CR-6260. The results for those six locations show that most locations have an environmentally assisted fatigue adjusted cumulative usage factor of less than 1.0. However, high pressure injection/makeup (HPI/MU) nozzle stainless steel safe end and associated Alloy 82/182 weld had environmentally adjusted CUFs greater than 1.0. Therefore, the company replaced the HPI/MU nozzle safe end and associated Alloy 82/182 weld prior to entering the period of extended operation.

The effects of environmentally assisted fatigue for each NUREG/CR-6260 location will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.4 Environmental Qualification of Electrical Equipment

The Environmental Qualification (EQ) of Electrical Components Program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, components in the EQ program that are not qualified for the full current license term (40 years) are required to be refurbished, replaced, or have their qualification extended prior to reaching the limits established in the evaluation. The EQ program ensures that the environmentally qualified components are maintained in accordance with their qualification bases. Equipment qualification evaluations for components in the EQ program that specify a qualification of at least 40 years are TLAA's for license renewal.

Environmental qualification of electrical equipment will be managed by the Environmental Qualification (EQ) of Electrical Components Program [UFSAR Section 18.1.14] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.5 Containment Fatigue Analyses

Additional potential TLAAAs associated with the Containment structure were reviewed and are summarized in the following sections:

- Containment Vessel (Section 18.2.5.1)
- Containment Penetrations (Section 18.2.5.2)
- Permanent Canal Seal Plate (Section 18.2.5.3)

18.2.5.1 Containment Vessel

The containment vessel is a Class B vessel as defined in the ASME Section III, Paragraph N-132, 1968 Edition through Summer Addenda 1969. The containment vessel meets the requirements for Paragraph N-415.1 of ASME Section III, thereby justifying the exclusion of cyclic or fatigue analyses in the design of the containment vessel. Analysis of 400 pressure cycles (from -0.67 psig to 45 psig) and 400 temperature cycles (from 30°F to 120°F) were performed against the requirements of ASME Section III, Paragraph N-415.1. The 400 cycles were based on a conservative estimate of anticipated cycles for 40 years of operation. Details of the ASME Section III, Paragraph N-415 analysis are as follows:

- N-415.1(a)

The number of times (including startup and shutdown) that the pressure will be cycled from atmospheric pressure to operating pressure and back to atmospheric pressure must not exceed the number of cycles on Figure N-415(A) of ASME Section III, corresponding to an S_a value of 3 times S_m .

3 S_m is equal to 56,250 psi, and from Figure N-415(A) the corresponding number of cycles is equal to 1,800. The specified number of 400 pressure cycles is less than the 1,800 cycles from Figure N-415(A). Therefore, the condition in N-415.1(a) is met.

- N-415.1(b)

Specified full range of pressure fluctuations may not exceed the quantity $1/3 \times$ design pressure $\times S_a/S_m$. S_a is the value from Figure N-415(A) for 400 cycles.

$$1/3 \times 36 \times 125,000/18,750 = 80 \text{ psi}$$

Specified full range of pressure fluctuations is 45 psi (-25 to 20 psi) and is less than 80 psi. Therefore, the condition in N-415.1(b) is met.¹

- N-415.1(c)

The temperature difference in degrees F between any two adjacent points during normal operation and during startup and shutdown must not exceed $S_a/(2E\alpha)$.

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For a mean temperature of 70°F, $120,000 / 2(27.9 \times 10^6)(6.07 \times 10^{-6}) = 358^\circ\text{F}$.

Temperature cycle range of 90°F (from 30°F to 120°F) is less than 358°F.
Therefore, the condition in N-415.1(c) is met.

- N-415.1(d)

The temperature difference in degrees F between any two adjacent points does not change during normal operation by more than $S_a/(2E\alpha)$.

For a mean temperature of 70°F, $120,000 / 2(27.9 \times 10^6)(6.07 \times 10^{-6}) = 358^\circ\text{F}$

Temperature cycle range of 90°F (from 30°F to 120°F) is less than 358°F.
Therefore, the condition in N-415.1(d) is met.

- ¹ The pressure cycle range used in the fatigue waiver evaluation is from -25 to 20 psi for a full range pressure fluctuation of 45 psi. However, the possible full range pressure fluctuation is from -0.67 to 45 psig based on the containment vessel design allowable negative pressure of -0.67 psig and the containment vessel pneumatic test pressure of 45 psig (design pressure of 36 psig times 1.25). This adjusted full range pressure fluctuation of 45.67 psi is less than the 80 psi value determined in N-415.1(b) above. Therefore, the condition in N-415.1(b) is met.

The 60-year projected cycles for plant heatup and cooldown are 128 and are less than the specified 400 pressure cycles and 400 temperature cycles. Therefore, the values of 400 pressure cycles and 400 temperature cycles used to exclude fatigue analyses will not be exceeded for 60 years of operation.

The TLAA associated with exclusion of the containment vessel from fatigue analyses per ASME Section III, Paragraph N-415.1 remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.2.5.2 Containment Penetrations

There are no fatigue analyses, and hence no TLAA, associated with the containment vessel penetration assemblies.

18.2.5.3 Permanent Canal Seal Plate

The permanent canal seal plate (also known as permanent reactor cavity seal plate) spans the gap between the reactor vessel and the fuel transfer canal floor, and retains water in the canal when the canal is flooded. The permanent canal seal plate is made up of a support structure that rests on the shield plate and reactor vessel seal ledge and a seal membrane that covers the support structure and is welded to the shield plate and reactor vessel seal ledge.

The fatigue analysis of the permanent canal seal plate seal membrane installed in 2004 shows that the maximum fatigue cumulative usage factor location is the inner leg to the reactor vessel seal ledge weld. A limit of 50 zero-to-full power cycles is recommended to meet the ASME Code requirement of maintaining the cumulative usage factor less than 1.0. The permanent canal seal plate is projected to experience 51 heatup and cooldown cycles from the date of installation (2004) through the end of the period of extended operation. However, the number of occurrences of permanent canal seal plate heatup and cooldown is tracked by the Fatigue

Monitoring Program [UFSAR Section 18.1.16] to assure that action is taken before the analyzed number of transients is reached.

The effects of fatigue of the permanent canal seal plate will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.6 Inservice Inspection – Fracture Mechanics Analyses

10 CFR 50.55a(g) requires an Inservice Inspection program to verify the integrity of the reactor coolant pressure boundary. Flaws detected during examination are compared to acceptance standards established in ASME Section XI. Unacceptable flaws require detailed analyses, repair, or replacement.

Acceptance via fracture mechanics analysis requires a prediction of flaw growth considering a chosen evaluation period, i.e., no shorter than the time until the next inspection following discovery of the flaw or as long as the remaining service life of the plant. Flaw indications that are determined not to grow beyond acceptance limits during the evaluation period are justified for continued operation. Fracture mechanics analyses performed for the life of the plant are TLAAAs that typically involve the same design transient cycle assumptions considered in the current licensing basis.

18.2.6.1 Reactor Coolant System Loop 1 Cold Leg Drain Line Weld Overlay Repair

A full structural overlay repair was performed for an axial indication found on the Reactor Coolant System Loop 1 cold leg drain line during the Cycle 14 refueling outage. The structural weld overlay of the cold leg drain nozzle was designed consistent with the requirements of ASME Section XI; Code Case N-504-2; Non-mandatory Appendix Q; and was supplemented by additional design considerations specific to the cold leg drain nozzle-to-elbow weld.

Fatigue Crack Growth Analysis

With respect to the potential for flaw growth, the reactor coolant pump 1-1 inlet cold leg drain line nozzle-to-elbow weld overlay is designed as a standard overlay (full structural) assuming a 360-degree flaw through the original pipe wall. As such, no credit is taken for any of the original pipe wall. The overlay material is Alloy 52, which is resistant to stress-corrosion cracking, and as such, flaw growth into the overlay by this mechanism is not expected. The presence of compressive residual stresses on the inside of the component after the overlay application also mitigates stress-corrosion cracking and minimizes fatigue crack growth into the overlay.

A fatigue crack growth analysis was performed to demonstrate that flaws equal to, or greater than, the maximum flaw sizes that could have escaped detection during the performance of the ultrasonic examinations would not grow unacceptably in the nozzle, so as to undermine the basis for the weld overlay. The dissimilar metal weld (DMW) contained an axial indication in the nozzle weld butter material (Alloy 182) for which no qualified depth sizing was performed. However, supplemental examinations confirmed that the indication was not present in the outer two-thirds of the wall thickness. Therefore, a flaw depth of one-third of the wall thickness was assumed for the axial and circumferential crack growth evaluation. Stress intensity factors (K) versus flaw depth were computed for three paths through the original DMW and butter, for both axial and circumferential cracks (six cases). For all six crack growth cases, no fatigue or primary water stress corrosion cracking (PWSCC) growth was predicted, as both K_{\max} and K_{\min} were negative for an assumed initial flaw size of one-third of the original base metal thickness.

Plant design cycles multiplied by a factor of 1.5 were used as an input to the structural weld overlay fatigue crack growth analysis. Therefore, the fatigue crack growth analysis is a time-limited aging analysis that requires disposition for license renewal. The company performed a comparison of the design cycles (original design cycles multiplied by a factor of 1.5) that were used in the fatigue crack growth analysis to the 60-year projected cycles provided in License Renewal Application Table 4.3-1, "60-Year Projected Cycles," and determined that the analyzed cycles bound the 60-year projected cycles. Therefore, the fatigue crack growth analysis associated with the RCS Loop 1 cold leg drain structural weld overlay remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Fatigue Analysis

The fatigue analysis estimated cycles for 60 years based on the original design cycles. Because this analysis is based on a specific number of cycles, it is considered a TLAA. All cumulative usage factors for the reactor coolant pump drain line weld overlay are less than 1.0.

The effects of fatigue on the reactor coolant pump drain line weld overlay repair will be managed by the Fatigue Monitoring Program [UFSAR Section 18.1.16] for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.7 Other Plant-Specific Time-Limited Aging Analyses

The TLAAs that do not fit into any of the previous major categories are evaluated below.

18.2.7.1 Leak-Before-Break

The leak-before-break (LBB) concept relies on the plant's ability to detect leakage from a through-wall flaw and then take appropriate action before that flaw grows to the point of pipe failure. Analyses showed that postulated flaws producing detectable leakage exhibit stable growth, and thus, allow a controlled plant shutdown before any potential exists for catastrophic piping failure.

The LBB analyses were updated to include the Alloy 52 weld overlays that were installed on the reactor coolant pump suction and discharge nozzles for PWSCC mitigation. These analyses considered fatigue crack growth, and PWSCC. Because these analysis considerations could be influenced by time, LBB analyses are considered to be TLAAs. Fatigue crack growth and thermal aging are addressed separately below.

Fatigue Crack Growth

The LBB analysis postulated surface flaws at the piping system locations with the highest stress coincident with the lower bound of material properties for the base metal and welds. The fatigue crack growth analysis for postulated flaws was performed to demonstrate that a surface flaw is likely to propagate in the through-wall direction and develop an identifiable leak before it will propagate circumferentially around the pipe to such an extent that it could cause a double-ended pipe rupture under faulted conditions. The fatigue crack growth analysis used plant design transients.

Application of weld overlays on the reactor coolant pumps (RCPs) suction and discharge nozzle dissimilar metal welds (DMW) required an update to the DBNPS LBB evaluation. As part of the updated LBB evaluation, specific fatigue crack growth analyses were performed for the Alloy

82/182 RCP nozzles DMW to demonstrate that the post weld overlay crack growth is very minimal for balance of plant life. In the fatigue crack growth analyses, plant design transients multiplied by a factor of 1.5 were used to conservatively define cycles for 60 years of operation.

The design cycle assumption used in these fatigue flaw growth analyses bound 60-year projected cycles.

Therefore, the LBB fatigue flaw growth analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Thermal Aging

The only stainless steel materials addressed in the LBB analysis are the safe ends welded to the reactor coolant pump casings and the casings themselves; with the pump casings being the only cast stainless steel components.

The updated LBB analysis was based on saturated embrittlement of the cast austenitic stainless steel (CASS) casings such that there is no embrittlement TLAA.

Aging management review of the RCS determined reduction of fracture toughness due to thermal embrittlement of CASS components to be an aging effect requiring management for the reactor coolant pump casings. Therefore, the effects of thermal aging on CASS components in the approved LBB piping will be managed by the Inservice Inspection Program [UFSAR Section 18.1.24] for the period of extended operation.

The effects of thermal aging on CASS components in the approved LBB piping are not a TLAA.

18.2.7.2 Metal Corrosion Allowance for Pressurizer Instrument Nozzles

UFSAR Section 5.2.3.2 indicates that pressurizer nozzle repairs and replacements have resulted in a portion of the carbon steel pressurizer nozzle bore being exposed to reactor coolant. This resulted in an increase of the general corrosion rate of the pressurizer shell base metal in the nozzle bores from zero to 1.42 thousandths of an inch (mils) per year. Over the 9 years from the installation of this modification to the end of the original licensed period, this will result in a loss of 13 mils of the pressurizer carbon steel shell in the nozzle annular regions. The allowable radial corrosion limit, calculated per ASME Section III, is 293 mils for the level instrument nozzles, 493 mils for the sample nozzle and 495 mils for the vent and thermowell nozzles. This corrosion analysis is a TLAA.

Loss of material in the annular region of the repaired pressurizer nozzles has been projected through the end of the period of extended operation and remains below the allowable radial corrosion limit, to meet ASME Section III, Class 1 Code design for the nozzles.

The corrosion allowance TLAA for the pressurizer nozzle annular regions has been projected through the period of extended operation in accordance with 10 CFR 54.21(c)(ii).

18.2.7.3 Reactor Vessel Thermal Shock due to Borated Water Storage Tank Water Injection

UFSAR Section 5.2 addresses integrity of the reactor coolant pressure boundary and the analysis to demonstrate that the reactor vessel can safely accommodate the rapid temperature change associated with the postulated operation of the Emergency Core Cooling System (ECCS) at the end of the vessel's design life. The analysis documents the reactor vessel

integrity during a small steam line break, which creates a pressurized thermal shock (PTS) condition. This transient generates the greatest level of stress in the reactor vessel. Technical Specifications allow the borated water storage tank (BWST) water temperature to be as low as 35°F. The analysis was revised for license renewal to use reactor vessel embrittlement values that bound the period of extended operation.

The revised fracture mechanics analysis evaluated the integrity of the reactor vessel against PTS for 52 EFPY considering the 35°F minimum temperature for the BWST. Several locations in the reactor vessel were analyzed for PTS, and all locations have demonstrated service life greater than 52.0 EFPY. Flaws do not initiate for any of the postulated flaw depths. The minimum critical margin to applied pressure margin is 2.21 at the nozzle belt forging.

The reactor vessel integrity analysis has been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

18.2.7.4 High Pressure Injection / Makeup Nozzle Thermal Sleeves

During the Cycle 5 refueling outage, DBNPS discovered a failed thermal sleeve for HPI/MU nozzle A-1. Corrective actions included assessment and preservation of the structural integrity of the nozzle, which had experienced thermal cycling due to the thermal sleeve failure. The makeup flow path was re-routed from nozzle A-1 to nozzle A-2 during the Cycle 6 refueling outage (1990) as one of the corrective actions. Fracture mechanics analysis of thermal sleeve life under various makeup flow cycling conditions predicted a thermal sleeve lifetime exceeding 20 eighteen-month operating cycles under current makeup flow control conditions.

Axial cracking was found on the A-1 and A-2 thermal sleeves during the Cycle 13 refueling outage that ended in March 2004. The A-1 and A-2 thermal sleeves were replaced at this time. The A-2 thermal sleeve, which has the RCS makeup flow directed through it on a regular basis, was examined in the 2006, 2010 and 2014 outages which no evidence of cracking noted. From 2004 to 2012, the average RCS makeup flowrate increased from approximately 25 gpm to 42 gpm. This increase in RCS makeup flowrate pushes the zone of mixing (hot RCS water and relatively cool RCS makeup water) into the RCS piping. The A-2 thermal sleeve is therefore not subjected to the cyclic thermal stresses encountered in previous operating cycles.

All four thermal sleeves were replaced during the HPI nozzle Alloy 600 mitigation that occurred in the Cycle 19 refueling outage that ended in May of 2016. Periodic review of makeup flowrate into the RCS is performed to ensure sustained operation with low makeup flowrates into the RCS does not occur. Occurrence of future examinations will be driven by the results of this review.

The effects of cracking on the makeup nozzle thermal sleeve will be managed by the Inservice Inspection Program [UFSAR Section 18.1.24] through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

18.2.7.5 ASME Code Case N-481 Evaluation

The reactor coolant pumps (RCPs) are the only ASME Code Class 1 pumps installed at DBNPS. The pump casings are constructed of cast austenitic stainless steel. The applicable ASME Code for the current Third Ten-Year Inspection Interval for DBNPS is ASME Section XI, 1995 Edition, through the 1996 Addenda, as modified by 10 CFR 50.55a or relief granted in accordance with 10 CFR 50.55a. Examination Category B-L-1 of this Code year requires volumetric examination on pump casing welds. ASME Code Case N-481, "Alternative

Examination Requirements for Cast Austenitic Pump Casings,” provides an alternative to the volumetric examination requirement. This code case allows the replacement of volumetric examinations of primary loop pump casings with fracture mechanics-based integrity evaluation (Item (d) of the code case) supplemented by specific visual examinations. DBNPS has invoked the use of Code Case N-481 in place of the volumetric examination requirements of Code Category B-L-1. The NRC has accepted Code Case N-481 for use in inservice inspection programs.

Code Case N-481 requires an evaluation to demonstrate the safety and serviceability of the pump casings. The evaluation for the DBNPS RCPs required by Code Case N-481 is documented in Structural Integrity Associates (SIA) report SIR-99-040, *ASME Code Case N-481, Evaluation of Davis-Besse Reactor Coolant Pumps* [Reference 12]. This evaluation assumed a quarter thickness flaw, with length six times its depth, and showed that the flaw will remain stable considering the stresses and material properties of the pump casing. To determine stability of the postulated flaw, a fracture mechanics evaluation was performed that included a fatigue crack growth analysis to demonstrate that a small initial assumed flaw (10 percent through-wall), corresponding to the acceptance standards of ASME Code, Section XI, Subarticle IWB-3500, would not grow to quarter thickness during plant life. There are two potential time-dependencies in the Code Case N-481 evaluation.

1. The fracture toughness of the cast austenitic stainless steel is not time dependent as the DBNPS ASME Code Case N-481 analysis used a lower bound fracture toughness of 139 ksi $\sqrt{\text{in}}$ that bounds the saturation fracture toughness of the DBNPS material.
2. The fatigue crack growth analysis is based on design cycles for a 40-year plant life and therefore, is a TLAA requiring analysis and disposition for license renewal.

With respect to Item No. 1 above, the saturation fracture toughness was determined using the methodology outlined in NUREG/CP-0119, Volume 2, pages 151-178, “Proceedings of the U.S. Nuclear Regulatory Commission, 19th Water Reactor Safety Information Meeting held at Bethesda, MD, October 28-30, 1991,” and considering all available certified material test reports (CMTRs) for the base material and welds of the DBNPS RCP casings. The saturation fracture toughness value of 139 ksi $\sqrt{\text{in}}$ was the minimum calculated for all the CMTRs considered in the evaluation. This minimum saturation fracture toughness value has since been calculated using NUREG/CR-4513, Revision 1, “Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems.” Using the methodology and correlation in this NUREG results in the same minimum saturation fracture toughness value for the pump casings.

The fracture toughness for welds considering thermal aging has also been presented in NUREG/CR-6428, “Effects of Thermal Aging on Fracture Toughness and Charpy-Impact Strength of Stainless Steel Pipe Welds.” A conservative J_{1c} fracture toughness value of 40 KJ/m² based on the absolute minimum of all available data is provided in this document for aged stainless steel welds; this J_{1c} fracture toughness value translates to 80 ksi $\sqrt{\text{in}}$. This conservative fracture toughness value still bounds the calculated total applied stress intensity factors calculated in Table 4-5 of SIR-99-040, Revision 1, indicating that the conclusions of SIR-99-040, Revision 1, are unchanged even if the methodology outlined in NUREG-CR-6428 is used for the DBNPS pump casing welds.

With respect to Item No. 2 above, the fatigue crack growth analysis assumed an initial flaw size corresponding to the acceptance standards of ASME Code Section XI and considered all the significant plant transients. This analysis examined the design cycles and determined there

were 240 cycles that were significant to flaw growth in the RCPs. Then 2000 cycles were conservatively analyzed, and flaw growth (initial 10 percent assumed through-wall had grown only to 15 percent through-wall) remained well below the quarter-thickness postulated flaw. The analyzed cycles of 2000 bound the 60-year projected cycles shown in License Renewal Application, Table 4.3-1, "60-Year Projected Cycles," and therefore, the fatigue crack growth TLAA associated with the ASME Code Case N-481 evaluation will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.2.7.6 Crane Load Cycles

The load cycle limits for cranes was identified as a potential TLAA. The following DBNPS cranes are in the scope of License Renewal and have been identified as having a TLAA, which requires evaluation for 60 years:

- Containment Polar Crane (including Auxiliary Hoist)
- Reactor Service Crane
- Spent Fuel Shipping Cask Crane (including Auxiliary Hoist)
- Intake Structure Gantry Crane

These cranes are designed in accordance with Bechtel design specifications. These specifications require that the cranes shall be designed in accordance with the minimum requirements for Class A cranes as stated in Crane Manufacturers Association of America (CMAA) Specification 70 for Electric Overhead Traveling Cranes, except as the requirements are extended by the Bechtel specification; and, in the case of conflict, that the more stringent requirements shall govern. Class A cranes are designed for up to 100,000 load cycles.

- Containment Polar Crane (including Auxiliary Hoist)

The estimated number of cycles for 60 years of operation is bounded by 22,000 cycles. Less than 500 cycles are due to the main hoist with the remaining cycles due to the auxiliary hoist. The rate of occurrence is based on refueling outages, mid cycle outages with core off load and the final core off load at the end of 60 years of operation. In addition, 500 cycles are estimated for the pre-operational construction period and are included in the estimate of 22,000 cycles. Since the total number of cycles is at the low end of the allowable design value of up to 100,000 cycles, the containment polar crane (including auxiliary hoist) load cycle assumption remains valid for the period of extended operation.

- Reactor Service Crane

The estimated number of cycles for 60 years of operation is bounded by 8,000 cycles. The rate of occurrence is based on refueling outages, mid cycle outages with core off load and the final core off load at the end of 60 years of operation. In addition, 500 cycles are estimated for the pre-operational construction period and are included in the estimate of 8,000 cycles. Since the total number of cycles is at the low end of the allowable design value of up to 100,000 cycles, the reactor service crane load cycle assumption remains valid for the period of extended operation.

- Spent Fuel Shipping Cask Crane (including Auxiliary Hoist)

The estimated number of cycles for 60 years of operation is bounded by 18,000 cycles. The rate of occurrence is based on refueling outages, mid cycle outages with core off load and the final core off load at the end of 60 years of operation. In addition, 500 cycles are estimated for the pre-operational construction period and are included in the estimate of 18,000 cycles. Also, 3,600 cycles are estimated for crane usage during non-outage periods and are included in the estimate of 18,000 cycles. Since the total number of cycles is at the low end of the allowable design value of up to 100,000 cycles, the spent fuel shipping cask crane (including auxiliary hoist) load cycle assumption remains valid for the period of extended operation.

- Intake Structure Gantry Crane

The estimated number of cycles for 60 years of operation is bounded by 1,700 cycles. The rate of occurrence is based on crane usage throughout the calendar year at 20 cycles per year. In addition, 500 cycles are estimated for the preoperational construction period and are included in the estimate of 1,700 cycles. Since the total number of cycles is at the low end of the allowable design value of up to 100,000 cycles, the intake structure gantry crane load cycle assumption remains valid for the period of extended operation.

Therefore, the crane load cycle assumptions remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

18.2.8 References to Section 18.2

1. AREVA NP Document BAW-2241P-A, "Fluence and Uncertainty Methodologies," April 1999 (NRC Safety Evaluation Report included).
2. NRC Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Vessel Neutron Fluence," March 2001.
3. NRC Regulatory Guide 1.99, "Radiation Embrittlement of Reactor Vessel Materials," Revision 2.
4. AREVA NP Document BAW-2308 Revision 1-A, "Initial RTNDT of Linde 80 Weld Materials," March 2008.
5. Davis-Besse Nuclear Power Station, Unit No.1, Docket No. 50-346, License No. NPF-3, "Pressure and Temperature Limits Report," (ML11304A188).
6. AREVA NP Document BAW-10046A, "Method of Compliance with Fracture Toughness and Operational Requirements of 10CFR50, Appendix G," Revision 2.
7. AREVA NP Document BAW-2308 Revision 2-A, "Initial RTNDT of Linde 80 Weld Materials," March 2008.
8. Allen, Barry S. (FirstEnergy), Letter to NRC, L-09-072, "License Amendment Request to Incorporate the Use of Alternate Methodologies for the Development of Reactor Pressure Vessel Pressure-Temperature Limit Curves, and Request for Exemption from Certain Requirements Contained in 10 CFR 50.61 and 10 CFR 50, Appendix G," April 15, 2009.
9. NRC Letter to FirstEnergy Nuclear Operating Company, "Davis-Besse Nuclear Power Station, Unit 1-Exemption from the Requirements of 10 CFR Part 50.61 and 10 CFR Part 50, Appendix G," dated December 14, 2010 (ML103060213).
10. AREVA NP Document BAW-10013-A, "Study of Intergranular Separations in Low-Alloy Steel Heat-Affected Zones under Austenitic Stainless Steel Weld Cladding," Last Revised February 15, 1972.
11. NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," February 1995.
12. Structural Integrity Associates Report SIR-99-040, "ASME Code Case N-481, Evaluation of Davis-Besse Reactor Coolant Pumps" Rev. 1, September 2000 (ADAMS Accession No. ML011200090).
13. Davis-Besse License Renewal Project Document LRPD-02, "TLAA and Exemption Evaluation Results," Revision 10, May 23, 2013.
14. Davis-Besse License Renewal Project Document LRPD-03, "TLAA – Metal Fatigue," Revision 10, June 5, 2015.

TABLE 18-1

Davis-Besse License Renewal Commitments

Table 18-1 identifies those actions committed to for Davis-Besse Nuclear Power Station (DBNPS), Unit 1, in the DBNPS License Renewal Application (LRA). These regulatory commitments will be tracked within the Regulatory Commitment Management Program.

| Table 18-1 Davis-Besse License Renewal Commitments | | | | |
|---|---|--------------------------------|---|--|
| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
| 1 | Enhance the Aboveground Steel Tanks Inspection Program to: <ul style="list-style-type: none"> • Include a volumetric examination of tank bottoms to detect evidence of loss of material due to crevice, general, or pitting corrosion, or to confirm a lack thereof. Establish the examination technique, the inspection locations, and the acceptance criteria for the examination of the tank bottoms. Require that unacceptable inspection results be entered into the Corrective Action Program. Additional opportunistic tank bottom inspections will be performed whenever the tanks are drained. • Include tank inspections conducted in accordance with Table 4a, "Tank Inspection Recommendations," of License Renewal Interim Staff Guidance LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." • Include an inspection of the borated water storage tank (BWST) exterior surface prior to the period of extended operation for loss of material and cracking. Sufficient insulation will be removed to determine the condition of the exterior surface of the tank. At a | Ongoing | LRA and Letters L-11-153, L-13-160, L-14-085 and L-14-244 UCN 19-129 | A.1.2 B.2.2 and Responses to NRC RAIs B.2.2-1 from NRC Letter dated April 20, 2011, A.1-1 from NRC Letter dated March 26, 2013, NRC LR-ISG- 2012-02, and, NRC RAI |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|------------------------------|----------------|--|
| | <p>minimum, either 25 1-square-foot sections or 20 percent of the surface area of insulation will be removed to permit inspection of the exterior surface of the tank. The sample inspection points will be distributed in such a way that inspections will be performed near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect such as on top of stiffening rings. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring. As an alternative to removing the insulation, subsequent inspections may consist of examination of the exterior surface of the insulation for indications of damage to the protective outer layer of the insulation when the results of the initial inspection meet the following criteria:</p> <ol style="list-style-type: none"> 1. no loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction is observed, and 2. no evidence of stress corrosion cracking is observed. <p>The subsequent inspections will be performed during each 10-year period of the period of extended operation. If these subsequent inspections reveal damage to the exterior surface of the insulation, or there is evidence of water intrusion through the insulation, periodic inspections under the insulation will continue as conducted for the initial inspection and will be performed during each 10-year period of the period of extended operation.</p> | | | 3.0.3.4.3-02 from NRC Letter dated July 7, 2014 |
| 2 | Implement the Boral® Monitoring Program as described in LRA Section B.2.5 . | Prior to October 22, 2016 | LRA and | A.1.5 B.2.5 and |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|---|---|
| | | | Letter L-13-160 | Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 3 | <p>Enhance the Buried Piping and Tanks Inspection Program to:</p> <ul style="list-style-type: none"> • Add 1) bolting for buried Fire Protection System piping and 2) the emergency diesel fuel oil storage tanks (DB-T153-1, DB-T153-2) to the scope of the program. • Conduct annual ground potential surveys of the cathodic protection system. Monitor cathodic protection voltage and current monthly to determine the effectiveness of cathodic protection systems and, thereby, the effectiveness of corrosion mitigation. Trend voltage, current, and ground potential readings and evaluate for adverse changes. • Require that the activity of the jockey fire pump or equivalent parameter be monitored on at least a monthly interval. Conduct a flow test by the end of the next refueling outage when unexplained changes in jockey pump activity are observed. • Require that the directed buried pipe inspection locations be selected based on risk. • Require that the minimum number of buried in-scope piping inspections during the 30-40, 40-50, and 50-60 year operating period is one steel piping segment. Perform the directed buried steel pipe inspections each ten year interval based upon table 4a, "Inspections of Buried Pipe," in the XI.M41 aging | Prior to October 22, 2016 | LRA and Letters L-11-153, L-13-160, L-13-304 and L-14-114 | <p>A.1.7 B.2.7 and Responses to NRC RAIs B.2.7-1 from NRC Letter dated April 20, 2011, A.1-1 from NRC Letter dated March 26, 2013, and 2011-03-1 and 2011-03-2 from NRC Letter dated February 11, 2014</p> |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|-------------------------|--------|-----------------------------------|
| | <p>management program described in LR-ISG-2011-03. Each inspection will have a minimum of 10 feet of piping inspected.</p> <ul style="list-style-type: none"> Require that, IF the cathodic protection system for the emergency diesel generator fuel oil storage tanks (DB-T153-1 and DB-T153-2) meets the availability criteria of Table 4c "Inspections of Buried Tanks for all Inspection Periods," (i.e., footnotes 3.i, 3.ii and 3.iii) of LR-ISG-2011-03, Appendix A, "Revised GALL Report AMP XI.M41," THEN no Table 4c inspections of tanks DB-T153-1 and DB-T153-2 are required. Otherwise, perform inspections of tanks DB-T153-1 and DB-T153-2 in accordance with Table 4c of LR-ISG-2011-03. Require that ultrasonic testing (UT) thickness measurements of the manways and vents for emergency diesel generator fuel oil storage tanks T153-1 and T153-2 will be performed prior to entering the period of extended operation and every 10 years during the period of extended operation to ensure that the metal thickness in those areas remains satisfactory. Require that underground piping in the decay heat removal and low pressure injection system located in the borated water piping trench will be visually inspected during the 30-40, 40-50, and 50-60 year operating periods to confirm the absence of aging effects. Require that if adverse indications are detected, the inspection sample sizes, within the affected piping categories, are initially doubled and if adverse conditions are discovered in the expanded sample, the size of the follow-on inspections is determined by establishing the extent of condition and extent of cause, consistent with the Corrective Action Program. | | | |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|-------------------------|--------|-----------------------------------|
| | <p>Scheduling of additional examinations is based on the severity of the degradation identified and commensurate with the consequences of a leak or loss of function, but in all cases, the expanded sample inspection should be completed within the 10-year interval in which the original adverse indication was identified. Further inspections are conducted in locations with similar materials and environment, or the piping is replaced on a schedule based upon either the station's need to return the system to service for non-Technical Specification-related systems or the allowed outage time for Technical Specification-related systems.</p> <ul style="list-style-type: none"> • Require that an inspection of buried Fire Protection System bolting will be performed when the bolting becomes accessible during opportunistic or focused inspections. • Require that the inspections of buried piping be conducted using visual (VT-3 or equivalent) inspection methods. Excavation shall be a minimum of 10 linear feet of piping, with all surfaces of the pipe exposed. • Include the following acceptance criteria in the program procedure: <ul style="list-style-type: none"> ○ The cathodic protection survey acceptance criteria for protected piping and tanks, with the exception of the manways and vents at the top of the mound over emergency diesel generator fuel oil storage tanks T153-1 and T153-2, are the -850 mV relative to a copper/copper sulfate reference electrode (CSE), instant off and limiting critical potential not more negative than 1200 mV. For the | | | |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
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| | <p>manways and vents at the top of the mound over tanks T153-1 and T153-2, the acceptance criterion is the 100 mV minimum polarization testing criteria listed in NACE SP0169 2007;</p> <ul style="list-style-type: none"> ○ For coated piping or tanks, there should be either no evidence of coating degradation or the type and extent of coating degradation should be insignificant as evaluated by an individual possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification or an individual has attended the Electric Power Research Institute (EPRI) Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer-Based Training Course. Where damage to the coating has been evaluated as significant and the damage was caused by nonconforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation; ○ If metallic piping or tanks show evidence of corrosion, the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained; and, ○ Changes in jockey pump activity or equivalent parameter that cannot be attributed to causes other than leakage from buried piping are not occurring. | | | |
| 4 | Implement the Collection, Drainage, and Treatment Components Inspection Program as described in LRA Section B.2.9 . | Prior to October 22, 2016 | LRA and | A.1.9 B.2.9 and |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|---------------------------------------|---|
| | | | Letter L-13-160 | Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 5 | <p>Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Inspection as described in LRA Section B.2.11.</p> <p>Enhance the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Inspection to:</p> <ul style="list-style-type: none"> • Include high voltage connections to confirm the absence of aging effects for metallic electrical connections. | Prior to October 22, 2016 | LRA and Letters L-11-134 and L-13-160 | A.1.11 B.2.11 and Responses to NRC RAIs 3.6-3 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

Table 18-1
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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|---------------------------|--|---|
| 6 | Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Section B.2.12 . | Prior to October 22, 2016 | LRA and Letter L-13-160 | A.1.12 B.2.12 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 7 | Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program as described in LRA Section B.2.13 . | Prior to October 22, 2016 | LRA and Letter L-13-160 | A.1.13 B.2.13 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 8 | Enhance the External Surfaces Monitoring Program to: <ul style="list-style-type: none"> • Add systems which credit the program for license renewal but do not have Maintenance Rule intended functions to the scope of the program. • Perform opportunistic inspections of surfaces that are inaccessible or not readily visible during normal plant operations or refueling outages, such as surfaces that are insulated. | Prior to October 22, 2016 | LRA and Letters L-11-153, L-11-166, L-11-238, L-13-160 | A.1.15 B.2.15 and Responses to NRC RAIs 3.3.2.2.5-1 and B.2.2-2 from NRC Letter |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|-------------------------|-----------------|--|
| | <p>Surfaces that are accessible will be inspected at a frequency not to exceed one refueling cycle.</p> <ul style="list-style-type: none"> • Perform, in conjunction with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program, inspection and surveillance of elastomers and polymers exposed to air-indoor uncontrolled or air-outdoor environments, but not replaced on a set frequency or interval (i.e., are long-lived), for evidence of cracking and change in material properties (hardening and loss of strength) and loss of material due to wear. Specify acceptance criteria of no unacceptable visual indications of cracks or discoloration that would lead to loss of function prior to the next inspection, and of no hardening as evidenced by a loss of suppleness during manipulation. • Perform inspection of the control room emergency ventilation system air-cooled condensing unit cooling coil tubes and fins and the station blackout diesel generator radiator tubes and fins for visible evidence of external surface conditions that could result in a reduction in heat transfer. Specify acceptance criteria of no unacceptable visual indications of fouling (build up of dirt or other foreign material) that would lead to loss of function prior to the next scheduled inspection. • Manage cracking of copper alloys with greater than 15 percent zinc and stainless steel components exposed to an outdoor air environment through plant system inspections and walkdowns for evidence of leakage. Specify acceptance criteria of no unacceptable visual indications of cracks that would lead to loss of function prior to the next scheduled inspection. | | and L-14-085 | dated April 20, 2011, 3.3.2-2 from NRC Letter dated May 2, 2011, 3.3.2.2.5-2 from NRC Letter dated July 12, 2011, Supplemental RAI OIN-352 from NRC Region III IP-71002 Inspection, A.1-1 from NRC Letter dated March 26, 2013, and NRC LR-ISG- 2012-02 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|-------------------------|--------|-----------------------------------|
| | <ul style="list-style-type: none"> • Include inspection parameters and acceptance criteria for polymers, elastomers and metallic components as applicable in system inspection and walkdown documentation. Retain system inspection and walkdown documentation in plant records. • Inspect or remove portions of insulation from outdoor insulated components, and indoor insulated components exposed to condensation (because the in-scope component is operated below the dew point), to determine whether the exterior surface of the component is degrading or has the potential to degrade. Inspect a minimum of 20 percent of the in-scope piping length, or 20 percent of the surface area for components whose configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator), after the insulation is removed. Alternatively any combination of a minimum of 25 1-foot axial length sections and components for each material type is inspected. Inspection locations should focus on the bounding or lead components most susceptible to aging because of time in service, severity of operating conditions (e.g., amount of time that condensate would be present on the external surfaces of the component), and lowest design margin. The inspections will be conducted during each 10-year period of the PEO. The following are alternatives to removing insulation: <ul style="list-style-type: none"> a. Subsequent inspections may consist of examination of the exterior surface of the insulation with sufficient acuity to detect indications of damage to the jacketing or protective outer layer of the insulation when the results of the initial inspection meet the following criteria: | | | |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|---------------------------|---|---|
| | <p>i. No loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction is observed, and</p> <p>ii. No evidence of SCC is observed.</p> <p>If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or jacketing, or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation should continue as conducted for the initial inspection.</p> <p>b. 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 corrosion under insulation (CUI) is low for tightly adhering insulation. Tightly adhering insulation is considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation is visually inspected for damage to the moisture barrier with the same frequency as for other types of insulation inspections. These inspections are not credited towards the inspection quantities for other types of insulation.</p> | | | |
| 9 | <p>Enhance the Fatigue Monitoring Program to:</p> <ul style="list-style-type: none"> Provide for updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached. When the number of accrued cycles is within 75% of the allowable cycle limit for any transient, a condition report will be | Prior to October 22, 2016 | <p>LRA</p> <p>and</p> <p>Letters L-11-166</p> | <p>A.1.16</p> <p>B.2.16</p> <p>and</p> <p>Responses to NRC RAIs</p> |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|---------------------------|---|--|
| | <p>generated. For any transient whose cycles are projected to exceed the allowable cycle limit by the end of the next plant operating cycle (DBNPS operating cycles are normally two years in duration), the program will require an update of the fatigue usage calculation for the affected component(s).</p> <ul style="list-style-type: none"> Establish an acceptance criterion for maintaining the cumulative fatigue usage below the Code design limit of 1.0 through the period of extended operation, including environmental effects where applicable. | | and L-13-160 | B.2.16-3, B.2.16-4 and B.2.16-5 from NRC Letter dated April 20, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 10 | <p>Enhance the Fire Water Program to:</p> <ul style="list-style-type: none"> Include inspections and testing conducted in accordance with Appendix D, Table 4a, "Fire Water System Inspection and Testing Recommendations," of License Renewal Interim Staff Guidance LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation." Include augmented testing and inspections beyond those of Table 4a for portions of water-based fire protection system components that are (a) normally dry but periodically subjected to flow (e.g., dry-pipe or preaction sprinkler system components) and (b) cannot be drained or allow water to collect: <ol style="list-style-type: none"> In each 5-year interval, beginning 5 years prior to the period of extended operation, a flow test or flush sufficient to detect potential flow blockage will be conducted, or a visual | Prior to October 22, 2016 | LRA and Letters L-13-160, L-14-085 and L-14-244 | <p>A.1.18 B.2.18 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013, NRC LR-ISG-2012-02, and NRC RAI B.2.18-2 from</p> |

Table 18-1
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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|-------------------------|--------|--------------------------------------|
| | <p>inspection of 100 percent of the internal surface of piping segments will be conducted.</p> <p>2. In each 5-year interval of the period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subject to volumetric wall thickness inspections. Measurement points are obtained to the extent that each potential degraded condition can be identified (e.g., general corrosion, MIC). The 20 percent of piping that is inspected in each 5-year interval will be in different locations than previously inspected piping.</p> <p>If the results of a 100-percent internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections are necessary.</p> <ul style="list-style-type: none"> • Perform representative sprinkler head sampling (laboratory field service testing) or replacement prior to 50 years in-service (installed), and at 10-year intervals thereafter, in accordance with the 2011 Edition of NFPA 25, or until there are no untested sprinkler heads that will see 50 years of service through the end of the period of extended operation. • Include a requirement that, when visual inspections are used to detect loss of material, the inspection technique is capable of detecting surface irregularities that could indicate wall loss to below nominal pipe wall thickness due to corrosion and corrosion product deposition. Where such irregularities are detected, follow-up volumetric wall thickness examinations are performed. | | | <p>NRC Letter dated July 7, 2014</p> |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|---|--|
| | <ul style="list-style-type: none"> Include a requirement that, if the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material is removed and its source is determined and corrected. | | | |
| 11 | <p>Implement the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Section B.2.21.</p> <p>Enhance the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program to:</p> <ul style="list-style-type: none"> Include inaccessible underground lower service voltage cables (400VAC to 2kV). Not use 'significant voltage' (defined as being subjected to system voltage for more than twenty-five percent of the time) as a criterion for inclusion into the program. Include inspection of electrical manholes which contain power cables within the scope of the program. Inspect electrical manholes at least once per year. The frequency of inspections for accumulated water will be established and adjusted based on plant-specific inspection results. Also, manhole inspections will be performed in response to event-driven occurrences (e.g., heavy rain or flooding). Include a requirement in preventive maintenance activities PM 4297, PM 4294, PM 8025, and PM 4296 to generate a condition report in cases where in-scope inaccessible non-EQ power cable manhole inspection identifies submerged cables. | Prior to October 22, 2016 | <p>LRA</p> <p>and Letters L-11-134 and L-13-160</p> | <p>A.1.21 B.2.21 and Responses to NRC RAIs B.2.21-1 and B.2.21-3 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013</p> |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|---------------------------|---------------------------------------|--|
| | <p>Although the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program, preventive maintenance activities exist for inspection of water accumulation in the manholes associated with the in-scope inaccessible non-EQ power cables.</p> <ul style="list-style-type: none"> Perform cable testing on an initial frequency of at least every 6 years for power cables from 600 VAC to 13.8 kV and 8 years for power cables from 400 VAC to 600 VAC. Testing will be evaluated for more or less frequent performance intervals based on test results, operating experience, and industry consensus. | | | |
| 12 | <p>Enhance the Masonry Wall Inspection to:</p> <ul style="list-style-type: none"> Include and list the structures within the scope of license renewal that credit the program for aging management. Add an action to follow the documentation requirement of 10 CFR 54.37, including submittal of records of structural evaluations to records management. Specify that for each masonry wall, the extent of observed masonry cracking or degradation of steel edge supports or bracing is evaluated to ensure that the current evaluation basis is still valid. Corrective action is required if the extent of masonry cracking or steel degradation is sufficient to invalidate the evaluation basis. An option is to develop a new evaluation basis that accounts for the degraded condition of the wall (i.e., acceptance by further evaluation). Specify that for the masonry walls within the scope of license renewal, inspections will be conducted at least once every five years, with provisions for more frequent inspections in areas where significant loss of material or cracking is observed to | Prior to October 22, 2016 | LRA and Letters L-11-153 and L-13-160 | A.1.27 B.2.27 and Responses to NRC RAIs B.2.39-5 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|--|--|
| | ensure there is no loss of intended function between inspections. | | | |
| 13 | Implement the One-Time Inspection as described in LRA Section B.2.30. | Prior to October 22, 2016 | LRA and Letters L-11-153, L-11-166, L-11-218 L-11-237, L-11-252, L-13-160 and L-14-206 | A.1.30 B.2.30 and Responses to NRC RAIs 3.3.2.2.4.3-1 from NRC Letter dated May 2, 2011, Supplemental Question – Makeup Pump Casing Inspections, A.1-1 from NRC Letter dated March 26, 2013, and, 2014 Annual Update |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|--|---|
| 14 | Implement the PWR Reactor Vessel Internals Program as described in LRA Section B.2.32 . | Prior to October 22, 2016 | LRA and Letter L-13-160 | A.1.32 B.2.32 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 15 | In association with the PWR Reactor Vessel Internals Program, a plant-specific inspection plan for ensuring the implementation of MRP-227 program guidelines, as amended by the safety evaluation for MRP-227, and DBNPS's responses to the plant-specific action items, as identified in Section 4.2 of the safety evaluation for MRP-227, will be submitted for NRC review and approval. * NOTE: The inspection plan will be submitted no later than two years after issuance of the renewed operating license or two years prior to the beginning of the period of extended operation (April 22, 2015), whichever is earlier. | COMPLETE | LRA and Letters L-11-252 and L-15-214 | A.1.32 B.2.32 and Response to NRC RAI B.2.32-1 from NRC Letter dated July 11, 2011 |
| 16 | Enhance the Reactor Head Closure Studs Program as follows: <ul style="list-style-type: none"> Select an alternate stable lubricant that is compatible with the fastener material and the environment. A specific precaution against the use of compounds containing sulfur (sulfide), including molybdenum disulfide (MoS₂), as a lubricant for the reactor head closure stud assemblies will be included in the program. | Prior to October 22, 2016 | LRA and Letters L-11-218 and L-13-160 | A.1.34 B.2.34 and Responses to NRC RAIs B.2.34-1 from NRC Letter |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|---------------------------|-------------------------|---|
| | <ul style="list-style-type: none"> Preclude the future use of replacement closure stud bolting fabricated from material with actual measured yield strength greater than or equal to 150 ksi except for use of the existing spare reactor head closure stud bolting. | | | dated June 20, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 17 | Enhance the Reactor Vessel Surveillance Program as follows: <ul style="list-style-type: none"> The Capsule Insertion and Withdrawal Schedule for DBNPS will be revised to schedule testing of the TE1-C capsule. | Prior to October 22, 2016 | LRA and Letter L-13-160 | A.1.35 B.2.35 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |
| 18 | Implement the Selective Leaching Inspection as described in LRA Section B.2.36 . | Prior to October 22, 2016 | LRA and Letter L-13-160 | A.1.36 B.2.36 and Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|--|--|---|--|
| 19 | Implement the Small Bore Class 1 Piping Inspection as described in LRA Section B.2.37 . | Completed within the six year period prior to October 22, 2016 | LRA and Letters L-11-153 and L-13-160 | A.1.37 B.2.37 and Responses to NRC RAIs B.2.37-2 from NRC Letter dated April 20, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 20 | Enhance the Structures Monitoring Program to: <ul style="list-style-type: none"> • Include and list the structures within the scope of license renewal that credit the program for aging management. • Include aging effect terminology (e.g., loss of material, cracking, change in material properties, and loss of form). • List ACI 349.3R and ANSI/ASCE 11-90 as references and indicate that they provide guidance for the selection of parameters monitored or inspected. • Clarify that a "structural component" for inspection includes each of the component types identified within the scope of license renewal as requiring aging management. | Prior to October 22, 2016 | LRA and Letters L-11-153, L-11-237, L-11-292, L-11-317, L-12-455, L-13-037 and L-13-160 | A.1.39 B.2.39 and Responses to NRC RAIs B.2.39-4, B.2.39-5, B.2.39-6 and B.2.39-7 from NRC Letter |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
|-------------|---|-------------------------|--------|--|
| | <ul style="list-style-type: none"> Require the responsible engineer to review site raw water pH, chlorides, and sulfates test results prior to the inspection to take into account the raw water chemistry for any unusual trends during the period of extended operation. Raw water chemistry data shall be collected at least once every five years. Data collection dates shall be staggered from year to year (summer-winter-summer) to account for seasonal variation. Perform an inspection for loss of material for carbon steel structural components subject to aggressive groundwater. Require the use of the Corrective Action Program for identified concrete or steel degradation. Specify that, upon notification that a below-grade structural wall or other in-scope concrete or metal structural component will become accessible through excavation, a follow-up action is initiated to the responsible engineer to inspect the exposed surfaces for age-related degradation. Such inspections will include concrete examination using acceptance criteria from NUREG-1801, XI.S6, Program element 6. Degradation found that exceeds the acceptance criteria will be trended and processed through the Corrective Action Program. List ACI 349.3R, ANSI/ASCE 11-90, and EPRI Report 1007933 as references and indicate that they provide guidance for detection of aging effects. Add an action to follow the documentation requirement of 10 CFR 54.37, including submittal of records of structural evaluations to records management. Add sufficient acceptance criteria and critical parameters to trigger an increased level of inspection and initiation of | | | <p>dated April 5, 2011, B.2.39-11 and 3.5.2.3.12-4 from NRC Letter dated July 21, 2011, Supplemental RAI B.2.39-11 from telecon held with the NRC on September 13, 2011, Supplemental RAI OIN-380 from Region III IP-71002 Inspection, B.2.4-1a from NRC Letter dated November 14, 2012, B.2.43-3a from NRC Letter</p> |

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| | <p>corrective action. Indicate that ACI 349.3R provides acceptable guidelines which will be considered in developing acceptance criteria for concrete structural elements, steel liners, joints, and waterproofing membranes. The acceptance criteria for visual inspection of coatings on in-scope concrete structures will be in accordance with ACI 349.3R. Plant-specific quantitative degradation limits, similar to the three-tier hierarchy acceptance criteria from Chapter 5 of ACI 349.3R, will be developed and added to the inspection procedure. The Structures Monitoring Program procedure will also be enhanced to reflect the "Periodic Evaluation" criteria defined in chapter 3.3 of ACI 349.3R. The Structures Monitoring Program procedure will include the "prioritization process" to develop a representative sample of areas to inspect in accordance with ACI 349.3R.</p> <ul style="list-style-type: none"> • Require that personnel performing the structural inspections meet qualifications that are commensurate with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," Chapter 7, "Qualifications of Evaluation Team." • The program procedure will be enhanced by specifying that, for the structures within the scope of license renewal, inspections will be conducted at least once every five years. • Conduct a baseline inspection of the structures within the scope of license renewal prior to entering the period of extended operation. • Require optical aids, scaling technologies, mechanical lifts, ladders or scaffolding for tall structures or difficult to reach areas of structures to allow visual inspections that meet the guidelines | | | <p>dated January 4, 2013, and A.1-1 from NRC Letter dated March 26, 2013</p> |

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| | <p>of Chapter 5 of ACI 349.3R. Select the areas to be inspected in accordance with the guidelines of Chapter 5 of ACI 349.3R to reflect the "Periodic Evaluation" criteria defined in Chapter 3.3 of ACI 349.3R. Include the "prioritization process" in the selection methodology to develop a representative sample of areas to inspect in accordance with ACI 349.3R.</p> <ul style="list-style-type: none"> • Monitor elastomeric vibration isolators and structural sealants for cracking, loss of material and hardening. • Supplement visual inspection of elastomeric vibration isolation elements by feel to detect hardening if the vibration isolation function is suspect. • Identify that: <ul style="list-style-type: none"> ○ Loose bolts and nuts and cracked high strength bolts are not acceptable unless accepted by engineering evaluation; ○ Structural sealants are acceptable if the observed loss of material, cracking, and hardening will not result in loss of sealing; and, ○ Elastomeric vibration isolation elements are acceptable if there is no loss of material, cracking, or hardening that could lead to the reduction or loss of isolation function. • Require that high strength (i.e., ASTM A540 Grade B23) structural bolting materials with an actual measured yield strength greater than or equal to 150 kilo-pounds per square inch (ksi) and greater than 1 inch in nominal diameter are monitored for stress corrosion cracking (SCC). Perform periodic visual inspections of susceptible ASTM A540 bolting to identify locations where A540 bolting may be exposed to a potentially corrosive environment for SCC. Complete the initial visual | | | |

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| | <p>inspections prior to entering the period of extended operation, and perform recurring inspections at an interval not to exceed five years. Perform volumetric examination (i.e., ultrasonic testing) on a sampling basis of bolting exposed to a corrosive environment, as determined by engineering evaluation, to a depth of at least 12 inches.</p> <ul style="list-style-type: none"> Require that personnel performing ultrasonic testing (UT) examinations of structural bolting have a current ASME Code Section XI, Appendix VIII, Supplement 8 endorsement. Revise the applicable structural bolting specifications to prevent future use of A540 bolting with measured yield strength equal to or exceeding 150 ksi. | | | |
| 21 | <p>Enhance the Water Control Structures Inspection to:</p> <ul style="list-style-type: none"> Include the Service Water Discharge Structure which is within the scope of license renewal. Include parameters monitored and inspected for water control structures, including the Service Water Discharge Structure, in accordance with applicable inspection elements listed in Section C.2 of Regulatory Guide 1.127 Revision 1. Descriptions of concrete conditions will conform with the appendix to the American Concrete Institute (ACI) publication, ACI 201. The use of photographs for comparison of previous and present conditions will be included as a part of the inspection program. Specify that water control structure periodic inspections are to be performed at least once every five years. | Prior to October 22, 2016 | <p>LRA</p> <p>and</p> <p>Letters L-11-153, L-11-292 and L-13-160</p> | <p>A.1.40 B.2.40 and Responses to NRC RAIs B.2.39-6 from NRC Letter dated April 5, 2011, Supplemental RAI OIN-379 from Region III IP-71002 Inspection,</p> |

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| | <ul style="list-style-type: none"> • Add an action to follow the documentation requirement of 10 CFR 54.37, including submittal of records of structural evaluations to records management. • Add sufficient acceptance criteria and critical parameters to trigger an increased level of inspection and initiation of corrective action. Indicate that ACI 349.3R provides acceptable guidelines which will be considered in developing acceptance criteria for water control structures. Plant-specific quantitative degradation limits, similar to the three-tier hierarchy acceptance criteria from Chapter 5 of ACI 349.3R, will be developed and added to the inspection procedure. The Structures Monitoring Program procedure will also be enhanced to reflect the "Periodic Evaluation" criteria defined in chapter 3.3 of ACI 349.3R. The Structures Monitoring Program procedure will include the "prioritization process" to develop a representative sample of areas to inspect in accordance with ACI 349.3R. • Conduct a baseline inspection of the structures within the scope of license renewal prior to entering the period of extended operation. • Require that loose bolts and nuts, cracked high strength bolts, and degradation of piles and sheeting (sheet pilings) are accepted by engineering evaluation or subject to corrective actions. Engineering evaluation will be documented and based on codes, specifications and standards such as American Institute of Steel Construction (AISC) specifications, Structural Engineering Institute / American Society of Civil Engineers (SEI/ASCE) 11, and codes, specifications or standards referenced in the DBNPS current licensing basis. | | | <p align="center">and A.1-1 from NRC Letter dated March 26, 2013</p> |

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| 22 | Enclose or otherwise protect the safety-related station ventilation radiation monitors located in the Turbine Building such that leakage and spray from surrounding piping systems does not adversely impact the intended function of the radiation monitors. | Prior to October 22, 2016 | Letter L-13-160 | Response to NRC RAI A.1-1 from NRC Letter dated March 26, 2013 |

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| 23 | In association with the time-limited aging analysis (TLAA) for effects of environmentally assisted fatigue of the high pressure injection (HPI) nozzle safe end including the associated Alloy 82/182 weld (weld that connects the safe end to the nozzle), replace the HPI nozzle safe end including the associated Alloy 82/182 weld for all four HPI nozzles prior to the period of extended operation. Apply the Fatigue Monitoring Program to evaluate the environmental effects and manage cumulative fatigue damage for the replacement HPI nozzle safe ends and associated welds. | Prior to October 22, 2016 | LRA and Letters L-11-107 L-11-203, L-11-334 and L-13-160 | A.2.3.4.2 A.2.7.4 and Responses to NRC RAIs 4.7.4-1 from NRC Letter dated April 15, 2011, 4.3-18 from NRC Letter dated June 17, 2011, 4.7.4-1 from NRC Letter dated October 11, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
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| 24 | Apply the elements of corrective actions, confirmation process, and administrative controls in the Quality Assurance Program Manual to the credited aging management programs and activities for safety-related and nonsafety-related structures and components determined to require aging management for the period of extended operation. | Prior to October 22, 2016 | LRA and Letters L-11-166 and L-13-160 | A.1 and Responses to NRC RAIs 3.0 from NRC Letter dated May 2, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 25 | Not used. | | | |
| 26 | Obtain and evaluate for degradation a concrete core bore from two representative inaccessible concrete components of an in-scope structure subjected to aggressive groundwater prior to entering the period of extended operation. Based on the results of the initial core bore sample, evaluate the need for collection and evaluation of representative concrete core bore samples at additional locations that may be identified during the period of extended operation as having aggressive groundwater infiltration. Select additional core bore sample locations based on the duration of observed aggressive groundwater infiltration. Document identified concrete or steel degradation in the Corrective Action Program. | COMPLETE | Letters L-11-153, L-11-237, L-11-292 and L-15-120 | Responses to NRC RAIs B.2.39-3 from NRC Letter dated April 5, 2011, B.2.39-11 from NRC Letter dated July 21, 2011, and Supplemental RAI B.2.39-11 |

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| | | | | from telecon held with the NRC on September 13, 2011 |
| 27 | DBNPS Surveillance Test Procedure DB-PF-03009, Revision 06, "Containment Vessel and Shielding Building Visual Inspection," Subsection 2.1.2, shall be enhanced to state, "Personnel who perform general visual examinations of the exterior surface of the Containment Vessel and the interior and exterior surfaces of the Shield Building shall meet the requirements for a general visual examiner in accordance with Nuclear Operating Procedure NOP-CC-5708, "Written Practice for the Qualification and Certification of Nondestructive Examination Personnel." These individuals shall be knowledgeable of the types of conditions which may be expected to be identified during the examinations." | Prior to October 22, 2016 | Letters L-11-134 and L-13-160 | Responses to NRC RAIs B.2.1-1 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 28 | Enhance the Fuel Oil Chemistry Program to: <ul style="list-style-type: none"> Require that internal surfaces of emergency diesel generator fuel oil storage tanks and day tanks, diesel oil storage tank, diesel fire pump day tank, and station blackout diesel generator day tank are periodically drained (at least once every 10 years) for cleaning and are visually inspected to detect potential degradation. If degradation is identified in a diesel fuel tank by visual inspections, a volumetric inspection is performed. Require that biological activity be monitored and trended at least quarterly. | Prior to October 22, 2016 | LRA and Letters L-11-134, L-11-238 and L-13-160 | A.1.20 B.2.20 and Responses to NRC RAIs B.2.20-1 and B.2.20-2 from NRC Letter dated April 5, 2011, |

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| | | | | Supplemental RAI OIN-368 from NRC Region III IP-71002 Inspection, and A.1-1 from NRC Letter dated March 26, 2013 |
| 29 | Enhance the Cranes and Hoists Inspection Program to: <ul style="list-style-type: none"> • Include visual inspections for loose bolts and missing or loose nuts in crane, monorail and hoist inspection procedures at the same frequency as inspections of rails and structural components. | Prior to October 22, 2016 | LRA and Letters L-11-153 and L-13-160 | A.1.10 B.2.10 and Responses to NRC RAIs B.2.10-2 from NRC Letter dated April 20, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| 30 | <p>Enhance the Leak Chase Monitoring Program to:</p> <ul style="list-style-type: none"> • Include acceptance criteria such that measurement of leakage from any monitoring line exceeding 25 ml/min will be documented in the Corrective Action Program for evaluation and potential corrective actions. Evaluation will include consideration of more frequent monitoring. • Analyze collected leak chase drainage for pH monthly and for iron every six months. Measurement of pH outside the range of 6.0-10.0 or iron exceeding 2500 ppm from any monitoring line will be documented in a condition report for evaluation and potential corrective actions. • Perform the leak chase inspection and cleaning recurring preventive maintenance (PM) activity at least every 18 months. • Inspect once per year for leakage migrating through the accessible outside walls and floor (from the ceiling side) of the pool and pits. Document the inspection results and retain in plant records. Indication of leakage through the walls will be documented in the Corrective Action Program. | Prior to October 22, 2016 | LRA and Letters L-11-153, L-11-238 and L-13-160 | A.1.25 B.2.25 and Responses to NRC RAIs B.2.25-5 from NRC Letter dated April 5, 2011, B.2.25-7 and B.2.39-10 from NRC Letter dated July 21, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| 31 | Incorporate reference to and the preventative actions of the Research Council for Structural Connections "Specification for Structural Joints Using ASTM A325 or A490 Bolts" into the DBNPS specifications and implementing procedures that address DBNPS structural bolting within the scope of license renewal. | Prior to October 22, 2016 | Letters L-11-153 and L-13-160 | Responses to NRC RAIs B.2.39-8 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 32 | Enhance the Closed Cooling Water Chemistry program to: <ul style="list-style-type: none"> Document the results of periodic inspections of opportunity, performed when components are opened for maintenance, repair, or surveillance. Ensure that a representative sample of piping and components will be inspected on a 10-year interval, with the first inspection taking place prior to entering the period of extended operation. Ensure that component cooling water radiochemistry is sampled on a weekly interval to verify the integrity of the letdown coolers and seal return coolers. | Prior to October 22, 2016 | LRA and Letters L-11-153, L-11-354 and L-13-160 | A.1.8 B.2.8 and Responses to NRC RAIs B.2.8-1 from NRC Letter dated April 20, 2011 Supplemental RAI 2.3.3.18-4 from telecon held with the NRC on November 9, 2011, |

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| | | | | and A.1-1 from NRC Letter dated March 26, 2013 |
| 33 | <p><u>Phase 1</u> Perform the following actions to reduce or mitigate the refueling canal leaks inside containment:</p> <ol style="list-style-type: none"> 1. Select and implement a leak detection method to locate the leakage area. 2. Evaluate temporary and permanent repair methods to stop or significantly reduce the leakage, and implement a repair plan. <p><u>Phase 2</u> Perform the following actions to evaluate the impact of refueling canal leaks on concrete and reinforcing steel structures. Discontinue core bores, testing and reinforcing steel inspections when indications of refueling canal leakage are no longer present:</p> <ol style="list-style-type: none"> 1. Perform a core bore in the south wall of the east-west section of the core flood pipe tunnel. <ol style="list-style-type: none"> a. Assess borated water degradation of the concrete by testing the core bore sample for compressive strength and by petrographic examination, and evaluate the results. b. Conduct a visual examination of the concrete and reinforcing steel to identify aging effects (e.g., | <p>Phase 1:</p> <p>Action 1 COMPLETE</p> <p>Action 2 COMPLETE</p> <p>Phase 2:</p> <p>Action 1 COMPLETE</p> | <p>Letters L-11-252, L-13-160 and L-14-206</p> | <p>Responses to NRC RAIs B.2.39-9 from NRC Letter dated July 27, 2011, and A.1-1 from NRC Letter dated March 26, 2013, and, 2014 Annual Update</p> |

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| | <p>concrete degradation or steel corrosion). Enter identified aging effects into the Corrective Action Program and evaluate in accordance with the requirements of the current licensing basis Maintenance Rule Program.</p> <p>2. If leakage from the refueling canal has not been eliminated or resumes by the beginning of the period of extended operation, then evaluate the concrete structures in a manner similar to the way that they were evaluated under Phase 2, Action 1. However, use acceptance criteria from the American Concrete Institute (ACI) Report 349.3R for the evaluation.</p> <p>3. If leakage from the refueling canal has not been eliminated or resumes during the period of extended operation, then evaluate the concrete structures again in a manner similar to the way that they were evaluated under Phase 2, Action 2. Perform evaluations every ten years until the end of the period of extended operation.</p> | <p>Action 2 prior to December 31, 2023</p> <p>Action 3 – Ongoing</p> | | |
| 34 | <p>Enhance the Bolting Integrity Program to:</p> <ul style="list-style-type: none"> Select an alternate stable lubricant that is compatible with the fastener material and the environment. A specific precaution against the use of compounds containing sulfur (sulfide), including molybdenum disulfide (MoS₂), as a lubricant will be included in the program. | Prior to October 22, 2016 | <p>LRA</p> <p>and Letters L-11-153 and L-13-160</p> | <p>A.1.4 B.2.4 and Responses to NRC RAIs B.2.4-3 from NRC Letter dated April 20, 2011,</p> |

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| | | | | and A.1-1 from NRC Letter dated March 26, 2013 |
| 35 | <p>Perform the following actions for each of two examinations (Phase 1 and Phase 2) of the Containment Vessel in the sand pocket region:</p> <ul style="list-style-type: none"> • Perform nondestructive examination (NDE) of the Containment Vessel from the outer surface at five areas of previously-identified groundwater in-leakage. <ul style="list-style-type: none"> ○ Examine the vessel at a minimum of three vertical grid locations at 12 inches nominal horizontal spacing at each area. Examine the Containment Vessel at a minimum of three elevations: <ol style="list-style-type: none"> 1. approximately 3 inches below the existing grout-to-vessel interface in the sand pocket region; 2. at the existing grout-to-vessel interface level in the sand pocket region; and, 3. approximately 3 inches above the existing grout-to-vessel interface in the sand pocket region. • Compare the ultrasonic test (UT) thickness readings to minimum ASME Code vessel thickness requirements and to the results obtained during previous UT examinations of the Containment Vessel. Determine the need for maintenance or repair of the Containment Vessel based on the results and evaluation of the examinations. | <p>Phase 1 COMPLETE</p> <p>and</p> <p>Phase 2 prior to December 31, 2025</p> | <p>Letters L-11-252 and L-14-206</p> | <p>Response to NRC RAI B.2.22-5 from NRC Letter dated July 21, 2011, and, 2014 Annual Update</p> |

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| | <ul style="list-style-type: none"> Document the results of each of the two examinations in the work order system. Document and evaluate adverse conditions in accordance with the Corrective Action Program for an evaluation of potential degradation of the steel Containment Vessel thickness over the longer term. | | | |
| 36 | <p>Perform the following actions related to the Containment Vessel sand pocket region each refueling outage:</p> <ul style="list-style-type: none"> Perform visual inspection of 100 percent of the accessible areas of the wetted outer surface of the Containment Vessel in the sand pocket region. Perform visual inspection of accessible dry areas of the outer surface of the Containment Vessel in the sand pocket region and the areas above the grout-to-steel interface up to Elevation 566 feet + 3 inches, - 1 inch. Perform visual inspection for deterioration (e.g., missing or damaged grout) of accessible grout and the containment exterior moisture barrier in the sand pocket area. Perform opportunistic visual inspections of inaccessible areas of the Containment Vessel in the sand pocket region when such areas are made accessible. Perform opportunistic visual inspections for deterioration (e.g., missing or damaged grout) of inaccessible grout in the sand pocket region when such areas are made accessible. Inaccessible grout is the grout below the normally-exposed surface of the grout in the sand pocket area. Address issues of pitting or microbiologically-influenced corrosion (MIC), and degraded grout, moisture barrier or sealant | Ongoing | Letters L-11-252 and L-11-354 | Responses to NRC RAI B.2.22-5 from NRC Letter dated July 21, 2011 and Supplemental RAI B.2.22-5 from telecons held with the NRC on October 5 and November 14, 2011 |

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| | <p>identified during the inspections using the Corrective Action Program.</p> <ul style="list-style-type: none"> Sample the water in the sand pocket region when sufficient volumes are available. The number of sampled water volumes will be determined by the number of water volumes observed and the size of those water volumes. Analyze the sample(s) for pH, chlorides, iron and sulfates. Treat or wash (or a combination thereof) the sand pocket area to reduce measured chloride concentrations to less than 250 parts per million (ppm) if the concentration of chlorides in a sample exceeds 250 ppm. Note: Water samples may be taken at different times during each outage. Engineering judgment may be used to determine the priority of the chemical analyses to be performed if sufficient water is not available in a given sample for all analyses. | | | |
| 37 | <p>Perform and evaluate core bores of the ECCS Pump Room No. 1 wall and the Room 109 ceiling.</p> <ul style="list-style-type: none"> The core bores will be deep enough to expose reinforcing bar in the wall and ceiling. The core samples from the core bores will be examined for signs of corrosion or chemical effects of boric acid on the concrete or reinforcing bars. The examination will include a petrographic examination. The reinforcing steel that will be exposed for a visual inspection will have corrosion products collected for testing. Degradation identified from the samples will be entered into the Corrective Action Program. The core bores will be performed in areas where leakage has been observed in the past. The first set of core bores will be performed prior to the end of 2014 (Phase 1). | <p>Phase 1 COMPLETE</p> <p>and</p> <p>Phase 2 prior to December 31, 2020</p> | <p>Letters L-11-153, L-11-238 and L-15-120</p> | <p>Responses to NRC RAI B.2.39-2 from NRC Letter dated April 5, 2011, and RAI B.2.39-10 from NRC Letter dated July 21, 2011</p> |

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| | <ul style="list-style-type: none"> The second set of core bores will be performed prior to the end of 2020 (Phase 2). Further core bores will be conducted, if warranted, based on the evaluation of the results of the inspection and testing of the core bores or if spent fuel pool leakage through the wall or ceiling recurs after the second set of core bores is performed. If spent fuel pool leakage through another wall or ceiling is identified, then core bores will be performed in a manner similar to that stated for the ECCS Pump Room No. 1 wall and the Room 109 ceiling. | | | |
| 38 | <p>Evaluate the concrete cracking observed on the underside of the spent fuel pool for necessary repairs.</p> <p>Note: A core bore of the Room 109 ceiling will be performed by the end of 2014 (see license renewal commitment 37). Degradation identified from the samples will be entered into the Corrective Action Program. The condition of the concrete and the reinforcing steel will be evaluated at that time to assist in determining what repairs, if any, need to be made to the underside of the spent fuel pool concrete. The criterion for determining the need to repair the cracking will be the continued capability of the structures to perform their intended functions during the period of extended operation.</p> | Prior to October 22, 2016 | Letters L-11-153, L-11-238 and L-13-160 | Responses to NRC RAIs B.2.39-2 from NRC Letter dated April 5, 2011, B.2.39-10 from NRC Letter dated July 21, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| 39 | <p>Address the potential for borated water degradation of the steel containment vessel through the following actions:</p> <ul style="list-style-type: none"> Access the inside surface of the embedded steel containment at a vertical height no greater than 10 inches above bottom dead center. A core bore will be completed by the end of 2014 (Phase 1). If necessary, a second core bore will be completed by the end of 2020 (Phase 2). If there is evidence of the presence of borated water in contact with the steel containment vessel, conduct non-destructive testing (NDT) to determine what effect, if any, the borated water has had on the steel containment vessel. Based on the results of NDT, perform a study to determine the effect through the period of extended operation of any identified loss of thickness in the steel containment due to exposure to borated water. | <p>Phase 1 COMPLETE and Phase 2 NOT REQUIRED PER EER 601251124</p> | <p>Letters L-11-153, L-11-237, L-13-180 and L-14-206 UCN 19-129</p> | <p>Responses to NRC RAIs B.2.22-2 from NRC Letter dated April 5, 2011, B.2.22-6 from NRC Letter dated July 27, 2011, Supplemental RAI B.2.22-6 from NRC telecon held on May 9, 2013, and, 2014 Annual Update</p> |

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| 40 | Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program as described in LRA Section B.2.41. | Prior to October 22, 2016 | LRA and Letters L-11-153 and L-13-160 | A.1.41 B.2.41 and Responses to NRC RAIs 3.3.2.2.5-1 and 3.3.2.71-2 from NRC Letter dated April 20, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 41 | Establish a preventive maintenance task to periodically replace the flexible connections exposed to fuel oil in the Fuel Oil System. | Prior to October 22, 2016 | Letters L-11-166 and L-13-160 | Responses to NRC RAIs 3.3.2.3.12-2 from NRC Letter dated May 2, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| 42 | <p>Enhance the Fatigue Monitoring Program to:</p> <ul style="list-style-type: none"> Evaluate additional plant-specific component locations in the reactor coolant pressure boundary that may be more limiting than those considered in NUREG/CR-6260. This evaluation will include identification of the most limiting fatigue location exposed to reactor coolant for each material type (i.e., CS, LAS, SS, and NBA) and that each bounding material/location will be evaluated for the effects of the reactor coolant environment on fatigue usage. Nickel-based alloy items will be evaluated using NUREG/CR-6909. Submit the evaluation to the NRC one year prior to the period of extended operation. | Prior to April 22, 2016 | LRA and Letter L-11-166 | A.1.16 B.2.16 and Response to NRC RAI B.2.16-2 from NRC Letter dated April 20, 2011 |
| 43 | Ensure that the current station operating experience review process includes future reviews of plant-specific and industry operating experience to confirm the effectiveness of the License Renewal aging management programs, to determine the need for programs to be enhanced, or indicate a need to develop new aging management programs. | COMPLETE | Letters L-11-188, L-13-160 and L-13-257 | Responses to NRC RAIs B.1.4-1 from NRC Letter dated May 19, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
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| 44 | Cathodically protect the EDG fuel oil storage tanks (DB-T153-1 and DB-T153-2) and the in-scope fuel oil and Service Water buried piping in accordance with NACE SP0169-2007 or NACE RP0285-2002. | COMPLETE | Letters L-11-203, L-11-218, L-13-160 and L-14-114 | Responses to NRC RAIs B.2.7-1 from NRC Letter dated April 20, 2011, as modified per telecon with the NRC held on June 7, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
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| 45 | Implement the Nuclear Safety-Related Coatings Program as described in LRA Section B.2.42. | Prior to October 22, 2016 | LRA and Letters L-11-203, L-11-218 and L-13-160 | A.1.42 B.2.42 and Responses to NRC RAIs XI.S8-1 from NRC Letter dated April 5, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 46 | Implement the Shield Building Monitoring Program as described in LRA Section B.2.43. | Prior to October 22, 2016 | LRA and Letters L-12-028 and L-13-160 | A.1.43 B.2.43 and Responses to NRC RAIs B.2.16-2 from NRC Letter dated December 27, 2012, and A.1-1 from NRC Letter |

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| | | | | dated March 26, 2013 |
| 47 | <p>Enhance the Inservice Inspection (ISI) Program - IWE to:</p> <ul style="list-style-type: none"> • Include surface examinations to monitor for cracking of containment stainless steel penetration sleeves, dissimilar metal welds, bellows, and steel components that are subject to cyclic loading but have no current licensing basis fatigue analysis. The inspection sample size will include 10 percent of the containment penetration population that is subject to cyclic loading but has no current licensing basis fatigue analysis. Penetrations included in the inspection sample will be scheduled for examination in each 10-year ISI interval that occurs during the period of extended operation. Should fatigue analyses be performed in the future for the subject containment penetrations, the surface examinations will no longer be required. | Prior to October 22, 2016 | <p>LRA</p> <p>and Letters L-11-238, L-11-292 and L-13-160</p> | <p>A.1.22 B.2.22 and Responses to NRC RAIs B.2.22-7 from NRC Letter dated July 21, 2011, Supplemental RAI B.2.22-7 from NRC telecons held on September 13 and 16, 2011, and A.1-1 from NRC Letter dated March 26, 2013</p> |

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| Item Number | Commitment | Implementation Schedule | Source | Related LRA Section No./ Comments |
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| 48 | Complete an investigation and needed repairs or modification of the degraded portion of the safety-related intake canal embankment. | COMPLETE | Letters L-11-238, L-13-160 and L-15-214 | Responses to NRC RAIs B.2.40-2 from NRC Letter dated July 21, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |
| 49 | Enhance the Nickel-Alloy Management Program to: <ul style="list-style-type: none"> Provide for inspection of dissimilar metal butt welds in accordance with the requirements of ASME Code Case N-770-1, "Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities, Section XI, Division 1," as modified by the Code of Federal Regulations, 10 CFR 50.55a(g)(6)(ii)(F). | Prior to October 22, 2016 | LRA and Letters L-11-238 and L-13-160 | A.1.28 B.2.28 and Responses to NRC RAIs B.2.28-1 from NRC Letter dated July 27, 2011, and A.1-1 from NRC Letter dated March 26, 2013 |

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|----|--|------------------------------|--|---|
| 50 | <p>Enhance the Inservice Inspection (ISI) Program – IWF to:</p> <ul style="list-style-type: none"> • Include monitoring of ASTM A490 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch nominal diameter for cracking using volumetric examination. The volumetric examinations will be performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section V, Article 5, Appendix IV, 2007 Edition through 2008 Addenda. The representative sample size will be equal to 20 percent (rounded up to the nearest whole number) of the entire IWF population of ASTM A490 high strength bolts in sizes greater than 1 inch nominal diameter, with a maximum sample size of 25 bolts. The selection of the representative sample will consider susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and as low as reasonably achievable (ALARA) radiation dose reduction principles. The frequency of examination will be once each 10-year inservice inspection interval beginning with the fourth interval that started September 21, 2012. • Include monitoring of ASTM A540 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch in nominal diameter for cracking. Periodic visual inspections of susceptible ASTM A540 bolting will be conducted prior to the period of extended operation and at an interval not to exceed five years to identify locations where the A540 bolting may be exposed to a potentially corrosive environment for stress corrosion cracking. If the visual inspections identify one or more bolts in a potentially corrosive environment, then an engineering evaluation will be performed to determine whether the bolting material had been subjected to a corrosive environment for stress corrosion cracking. The bolts determined to have been subjected to a corrosive environment for stress corrosion cracking comprise the population subject to sampling for volumetric examinations. The representative sample size is equal to 20 percent (rounded up to the nearest whole number) of the bolts in the sample | Prior to October 22, 2016 | LRA and Letters L-13-181 and L-13-199 | A.1.23 B.2.23 and Supplemental Responses to NRC RAI B.2.4-1b from telecons held with the NRC on April 11, April 24, May 2 and May 28, 2013 |
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| | <p>population, with a maximum sample size of 25 bolts. The volumetric examinations are performed in accordance with the requirements of ASME Code Section V, Article 5, Appendix IV. Volumetric examinations will be performed no later than the subsequent refueling outage following visual identification of bolting subject to a corrosive environment. Deferral of volumetric examinations to the subsequent refueling outage is not permitted if the visual inspection indicates evidence of contaminant penetration through the coatings. The frequency of examination is once each 10-year ISI interval beginning with the 4th interval that started September 21, 2012. For ASTM A540 high strength bolts that are not exposed to a corrosive environment, the volumetric examinations are waived based on plant-specific operating experience associated with the volumetric examination of the DBNPS reactor head closure studs (60 each) constructed of high strength ASTM A540 material where the studs are examined once each ISI interval, and after three intervals, no unacceptable indications have been noted.</p> <ul style="list-style-type: none"> As an alternative to the visual examinations and the subsequent volumetric examinations of ASTM A540 bolts subjected to a corrosive environment, the ISI Program – IWF provides an option to perform periodic volumetric examinations as follows. The program includes monitoring of ASTM A540 high strength bolting (i.e., actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) in sizes greater than 1 inch nominal diameter for cracking using volumetric examination. | | | |

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| | The volumetric examinations are performed in accordance with the requirements of ASME Code Section V, Article 5, Appendix IV. The representative sample size is equal to 20 percent (rounded up to the nearest whole number) of the entire IWF population of ASTM A540 high strength bolts in sizes greater than 1 inch nominal diameter, with a maximum sample size of 25 bolts. The selection of the representative sample considers susceptibility to stress corrosion cracking (e.g., actual measured yield strength) and ALARA radiation dose reduction principles. The frequency of examination is once each 10-year ISI interval beginning with the 4th interval that started September 21, 2012. | | | |
| 51 | Implement the Service Level III Coatings and Linings Monitoring Program. | Prior to October 22, 2016 | LRA and Letter L-14-061 | A.1.44 B.2.44 and Response to NRC RAI 3.0.3-3 from NRC Letter dated November 26, 2013 |

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| 52 | In response to MRP-227-A Applicant/Licensee Action Item 6, submit for NRC review and approval an evaluation justifying the acceptability of inaccessible and non-inspectable component items (core barrel cylinder including vertical and circumferential seam welds, former plates, external baffle-to-baffle bolts and their locking devices, core barrel-to-former bolts and their locking devices, and internal baffle-to-baffle bolts) for continued operation through the period of extended operation and, if necessary, provide a plan for replacement of the components. | Within one year of the detection of degradation exceeding the acceptance criteria of the linked MRP-227-A primary component items leading to expansion | LRA and Letters L-15-139 and L-15-166 | A.1.32 B.2.32 |
| 53 | In response to MRP-227-A Applicant/Licensee Action Item 7, develop and submit for NRC review and approval a plant-specific analysis to demonstrate that the Incore Monitoring Instrumentation (IMI) guide tube assembly spiders, Control Rod Guide Tube (CRGT) spacer castings, and additional RV Internals component items that may be fabricated from CASS, martensitic stainless steel, or martensitic precipitation-hardened stainless steel materials (e.g., Core Support Shield (CSS) vent valve top and bottom retaining rings) will maintain their functionality during the period of extended operation. The analysis will consider the possible loss of fracture toughness in these component items due to thermal embrittlement (TE) and/or irradiation embrittlement (IE) and may also need to consider limitations on accessibility for inspection and the resolution/sensitivity of the inspection techniques. The DBNPS analysis will be consistent with the licensing basis and the need to | One year prior to the MRP-227-A inspection of the applicable component items | LRA and Letters L-15-139 and L-15-166 | A.1.32 B.2.32 |

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| | maintain the functionality of the component items being evaluated under all licensing basis conditions of operation. | | | |
| 54 | In response to MRP-227-A Applicant/Licensee Action Item 8, develop a schedule, with completion prior to the period of extended operation, for the update and submittal for NRC review and approval of an evaluation for the period of extended operation regarding the effect of irradiation on the mechanical properties and deformation limits of the RV internals that was evaluated for the current term of operation in Appendix E of Topical Report BAW-10008, Part 1, Revision 1 supplemented by DB-1 UFSAR Appendix 4A. | Prior to October 22, 2016 | LRA and Letters L-15-139 and L-15-166 | A.1.32 B.2.32 |
| 55 | Perform the following actions to improve and maintain the fidelity of the data in the Flow-Accelerated Corrosion Program: <ul style="list-style-type: none"> • Perform a review of the CHECWORKS SFA model to determine which inputs are critical to the determination of fitness for service and which inputs are non-critical. This action will document the listing of all input fields within the software, and whether their accuracy affects the output of the model. • Perform a validation of the data inputs into CHECWORKS SFA. This task will include the validation of any input which would have consequence, as used by the CHECWORKS SFA software in the determination of fitness for service of piping and components for the Flow Accelerated Corrosion (FAC) program. Data contained within the CHECWORKS SFA model that does not impact fitness for service will be annotated during this validation as being non-critical to the function of the software, while still attempting to validate it. | Prior to October 22, 2016 | LRA and Letter L-15-192 | A.1.19 B.2.19 |

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| | <ul style="list-style-type: none"> • Document the results of the validation of the CHECWORKS SFA database. This action will create a document (Reference Material, Program Manual, etc.) that will serve as a listing of inputs into the CHECWORKS SFA database and be maintained as a quality record. • Revise the CHECWORKS SFA model to correct the restriction orifices' size/dimension for the orifice and flow elements identified in the Steam Line Failure Root Cause Evaluation. • Establish a list of components for the site that meet the bulleted items within Section 4.4.4 of NSAC-202L, Revision 4. Compile the inspection history of the relevant components. Perform an evaluation for any components without inspection data, and add components requiring inspection to 19RFO scope. These locations are to specifically include: <ul style="list-style-type: none"> ○ Locations downstream of orifices, flow elements, venturis, thermowells, angle valves, flow control valves or level control valves. ○ Locations or lines known to contain backing rings or counterbore. ○ Field-fabricated tees and laterals. ○ Nozzles. ○ Complex geometric locations such as components located within two diameters of each other (e.g., an elbow welded to a tee). | | | |

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| | <ul style="list-style-type: none"> ○ Components downstream of replaced components (upstream if expander), and components that have been replaced in the past if not upgraded to resistant material. ○ Components (including straight pipe) immediately downstream of FAC-resistant components (e.g., containing chromium greater than 0.10%). ○ Locations immediately downstream of turning vanes. ○ Expansion joints. ● Revise the Flow-Accelerated Corrosion Program procedure as follows: <ul style="list-style-type: none"> ○ Add requirements to the procedure that would involve review and selection of examination scope based on recommendations from NSAC-202L, Rev 4, Section 4.4.4. This action requires documentation of the basis for selection or exclusion of the scope for the given outage. Documentation would be in the form of discussion in the Outage Technical Report (pre-outage) and Outage Summary Report (post-outage). ○ Add a step that would require review, approval, and documentation of updates to the CHECWORKS SFA database. The scope of these changes would exclude data collected and evaluated during outages, but would be inclusive of all others (such as plant uprates, plant modifications, engineering change packages, etc.). Documentation for this step would be through an Engineering Evaluation Request. | | | |