Davis-BesseNPEm Resource

From: Klos, John
Sent: Wednesday, May 11, 2011 4:20 PM
To: Makeig, Katy; Erach Patel; Bob Nickell ; Bob Jackson; Roland Royal; Wayne Pavinich
Subject: Davis Besse RAI letters to applicant
Attachments: 2011-05-02 DB RAIs_ML111170204.pdf; 2011-04-05 DB RAIs_ML1108204900.pdf; 2011-04-20 DB RAIs ML110980718.pdf

All,

Attached are the distributions made to the applicant so far.

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May 2, 2011

Barry S. Allen
Vice President, Davis-Besse Nuclear
Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION–BATCH 3 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company, submitted an application pursuant to Title 10 *Code of the Federal Regulation* Part 54 for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staffs requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,

Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

cc w/encl: Listserv

DAVIS-BESSE NUCLEAR POWER STATION
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

RAI B.2.3-1

In LRA Section B.2.3, "Air Quality Monitoring Program," under the "scope of program" program element, the applicant stated that this program includes periodic sampling of the air quality in the instrument air system piping and piping components to ensure that the compressed air environment remains dry and free of contaminants, thereby ensuring that there are no aging effects requiring management for this system. SRP-LR, Appendix A.1.2.1.5, states that an aging effect should be identified as applicable for license renewal even if there is a prevention or mitigation program associated with that aging effect.

The staff reviewed LRA Table 3.3.2-17, Instrument Air System, and noted that for steel components in dried air, the applicant cited plant-specific footnote 318, which states that the Air Quality Monitoring Program ensures that the instrument air system remains dry and free of contaminants, thereby sustaining the aging management review conclusion that there are no aging effects that require management. However, the program has not been credited.

Justify why the LRA does not identify an aging effect as applicable for license renewal and credit the Air Quality Monitoring Program as a preventive program that manages this aging effect.

RAI B.2.3-2

In LRA Section B.2.3, "Air Quality Monitoring Program," under the "detection of aging effects" program element, the applicant stated that the presence of an environmental stressor (moisture), which could lead to corrosion of system components, is detected and moisture, if any, is removed to ensure air quality (and intended function) is maintained. SRP-LR Section A.1.2.3.4, states that this program element describes "when," "where," and "how," program data are collected, and that the method or technique and frequency may be linked to plant-specific or industry-wide operating experience, and to provide justification, including codes and standards referenced, that the frequency is adequate.

The staff reviewed LRA Section B.2.3 and noted that the applicant has not identified the frequency of periodic sampling nor provided any industry standards such as ISA or EPRI to confirm that the frequency is adequate.

Provide the frequency of periodic testing of contaminants and any industry standards used to determine the frequency.

RAI B.2.3-3

In LRA Section B.2.3, "Air Quality Monitoring Program," under the "acceptance criteria" program element, the applicant specified acceptance criteria for particulates, hydrocarbons and dew point as necessary for sampling of the instrument air system. SRP-LR Section A.1.2.3.6 states that the acceptance criteria of the program and its basis should be described.

The staff reviewed LRA Section B.2.3 and noted that the applicant has not identified the basis for the acceptance criteria.
Provide the basis for the acceptance criteria, such as current licensing basis (CLB) or an industry standard, to ensure that the instrument air system remains dry and free of contaminants.

RAI B.2.3-4

In LRA Section B.2.3, "Air Quality Monitoring Program," under the "operating experience" program element, the applicant stated that in 2007, one out of nine air samples drawn for particulate testing exceeded the Preventive Maintenance limit that was established as a threshold for further investigation, and the work order system was used to investigate and characterize the system piping that produced the high particulate loading. The staff reviewed the applicant's "operating experience" program element against the criteria in SRP LR Section A.1.2.3.1, which states that operating experience with existing programs should be discussed. The operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered.

The staff reviewed LRA Section B.2.3 and noted that the applicant did not describe in detail the cause of the abnormal particulate testing and corrective actions taken.

With regard to the particular operating experience described above, were any corrective actions taken that resulted in program enhancements? If so, provide additional details on the cause of the variance and associated corrective actions. Since 2007, have there been any additional air samples that have exceeded the Preventive Maintenance limit?

RAI B.2.9-1

In license renewal application (LRA) Section B.2.9, "Collection, Drainage and Treatment Components Inspection Program," under the "detection of aging effects" program element, the applicant stated that inspections will be conducted using visual (VT-3 or equivalent) inspection methods performed by qualified personnel following procedures consistent with the American Society of Mechanical Engineers (ASME) Code and 10 Part CFR 50, Appendix B. ASME Section III, Subsection IWA-2213, states that VT-3 examinations are conducted to determine the general mechanical condition of components and their supports. ASME Section III, Subsection IWA-2211, states that VT-1 examinations are conducted to detect discontinuities and imperfections on the surface of components including such conditions as cracks, wear, corrosion and erosion. Also, the comparable aging management program (AMP) in the Generic Aging Lessons Learned (GALL) Report, XI.M32, "One-Time Inspection," in the "detection of aging effects" program element recommends VT-1 or equivalent for detecting crevice and pitting corrosion.

This plant-specific program is credited to manage loss of material due to general, pitting and crevice corrosion, and cracking. A VT-3 or equivalent method may be satisfactory to detect general corrosion, but is not necessarily an acceptable method to detect crevice or pitting corrosion, and cracking.

Justify that VT-3 or equivalent inspection method will detect pitting and crevice corrosion.

RAI B.2.9-2

In LRA Section B.2.9, "Collection, Drainage and Treatment Components Inspection Program," under the "acceptance criteria" program element, the applicant stated that indications or relevant conditions of degradation detected during the inspections will be compared to pre-determined acceptance criteria. The applicant also stated that unacceptable inspection findings will include visible evidence of cracking, loss of material, or reduction in heat transfer due to fouling that could lead to loss of component intended function during the period of extended operation. Standard Review Plan for Reviewing of License Renewal Applications for Nuclear Power Plants (SRP-LR) Section A.1.2.3.6 states that the acceptance criteria of the program and its basis should be described.

The staff reviewed LRA Section B.2.9 and noted that the applicant has not identified the basis for the acceptance criteria.

Provide the basis and the description, such as manufacturer's recommendations or industry standards, for the acceptance criteria associated with this program.

RAI 2.3.3.18-2

LRA Section 2.3.3.18, "Makeup and Purification System," states that the letdown coolers, designated as DB-E25-1 and 2, are replaced periodically, are evaluated as short-lived components (consumables), and, therefore, are not subject to aging management review (AMR).

According to SRP-LR Section 2.1.3.2.2, replacement programs may be based on vendor recommendations, plant experience, or any means that establish a specific replacement frequency under a controlled program. It also notes that component replacements based on performance or condition are not generically excluded from AMR and performance or condition monitoring may be evaluated as programs to ensure functionality during extended operation.

The staff noted that previous LRAs for other sites have acknowledged problems with these specific heat exchangers, and in one case cracking in the tubes was attributed to high cycle fatigue during infrequent events. However, the related problems at these sites had apparently been resolved and the heat exchangers were being age managed in a routine manner similar to other heat exchangers. The staff also noted that LRA Section 3.3.2.2.4.1, which addresses heat exchangers in the same system, states that cracking due to cyclic loading is not identified as an aging effect requiring management. The bases for Davis-Besse's determination regarding cyclic loading is the subject of the NRC's RAI 3.3.2.2.4-1; however, the industry experience associated with the heat exchanger cracking issue, and Davis-Besse's periodic replacement of the heat exchangers in conjunction with its determination that cracking due to cyclic loading does not require age management, all appear to be integrally related.

The LRA did not include information regarding the replacement frequency, the bases for the frequency, or any discussion regarding the reasons these normally long-lived components need to be replaced. In order to evaluate the adequacy of age managing of other components in this system, information is needed to understand the extent of the condition and the reason for periodic replacement of these heat exchangers.

The staff requests the following information:

1. State the basis for the replacement frequency of letdown coolers, DB-E25-1 and 2. If the frequency is based on qualified life, then provide information to demonstrate that the cooler's intended function is being maintained consistent with current licensing basis immediately prior to replacement. If the frequency is based on performance or condition monitoring, then provide the AMP that manages the monitoring.

2. State the circumstances surrounding the need to replace these coolers, and provide details for the extent of condition and cause (e.g., other heat exchangers in similar configurations, other components in the system) that was conducted.

RAI 3.0

The NRC staff reviewed the AMPs described in Appendix A, "Updated Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs," of the license renewal application. The purpose of the review was to assure that the aging management activities were consistent with the staff's guidance described in NUREG-1800, Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," regarding quality assurance attributes of AMPs.

The staff determined that the AMP quality assurance attributes (Element 7 - Corrective Action, Element 8 - Confirmation Process, and Element 9 - Administrative Controls) described in Appendix B, Section B.1.3, "Quality Assurance Program and Administrative Controls," of the LRA for all programs credited for managing aging effects, were consistent with Branch Technical Position IQMB-1. Section B.1.3 states that the quality attributes would be implemented in accordance with the applicant's 10 CFR Part 50, Appendix B, quality assurance program and be applied to both safety-related and nonsafety-related structures and components (SCs) subject to the aging management programs during the period of extended operation. However, the applicant has not specifically addressed the application of the AMP quality attributes in Appendix A, "Updated Safety Analysis Report Supplement," to nonsafety-related SCs. Appendix A does not contain a specific statement that the quality attributes, implemented in accordance with the applicant's 10 CFR Part 50, Appendix B, quality assurance program, would be applied to both safety-related and nonsafety-related SCs subject to the AMPs during the period of extended operation.

The staff requests that the applicant supplement the information provided in Appendix A to state that the AMP quality attributes, implemented in accordance with the applicant's 10 CFR Part 50, Appendix B, quality assurance program, will be applied to both safety-related and nonsafety-related SCs subject to the AMPs during the period of extended operation.

RAI 3.1.1.70-1

GALL Report Rev. 1, item IV.C2-1 addresses Class 1 piping, fitting and branch connections less than nominal pipe size (NPS) 4, which are exposed to reactor coolant and subject to cracking due to stress corrosion cracking (SCC) and thermal and mechanical loading. It also recommends the ASME Section XI Inservice Inspection Subsections, IWB, IWC and IWD Program, Water Chemistry Program, and One-time Inspection of ASME Code Class 1 Small-bore Piping Program to manage the aging effect.

LRA Table 3.1.2-3, in Row Nos. 230 to 232 and 237 to 239, indicates that valve bodies less than 4 inches, made of cast austenitic stainless steel (CASS) and stainless steel respectively, are subject to cracking due to flaw growth, SCC and intergranular attack (IGA) in a borated reactor coolant environment. LRA Table 3.1.2-3 also indicates that the applicant will use the Inservice Inspection Program, pressure water reactor (PWR) Water Chemistry Program, and Small Bore Class 1 Piping Inspection Program to manage the aging effect. The LRA table further indicates that the valve bodies less than 4 inches are related to LRA Table 1 item 3.1.1-70 and consistent with GALL Report Rev. 1, item IV.C2-1.

LRA Section B.2.37 states that the Small Bore Class 1 Piping Inspection Program will detect and characterize cracking of small bore ASME Code Class 1 piping less than 4 inches NPS, which includes pipe, fitting, and branch connections.

LRA Section B.2.37 indicates that the scope of the Small Bore Class 1 Piping Inspection Program includes small-bore pipe, fitting and branch connections; however it does not discuss valve bodies. The staff noted that scope of components for the applicant's Small Bore Class 1 Piping Inspection Program does not include valve bodies and conflicts with the aging management review result to manage cracking in the CASS and stainless steel valve bodies less than 4 inches.

Clarify why the Small Bore Class 1 Piping Inspection Program is credited to manage cracking due to flaw growth, SCC and IGA of the stainless steel and CASS valve bodies less than 4 inches, when this program only includes small-bore pipe, fitting and branch connections. In addition, clarify how this program will manage this aging effect specific to stainless steel and CASS valve bodies less than 4 inches.

RAI 3.1.2.1.58-1

In LRA Table 3.1.2-1, item 99, the applicant states that it will manage loss of material of the upper reactor vessel head with the Boric Acid Corrosion Program. Consistent with this, in LRA Section B.2.29, "Nickel-Alloy Reactor Vessel Closure Head Nozzle Program," the applicant stated that the Boric Acid Corrosion Program will be used to manage wastage of the reactor vessel closure head surfaces, but also states that inservice inspections of the vessel closure head surfaces will be performed in accordance with ASME Code Case N-729-1. In addition to inspection requirements, ASME Code Case N-729-1 specifies the performance of evaluations for relevant conditions and prescribes methods for repair activities.

In LRA Section B.2.6, "Boric Acid Corrosion Program," the applicant did not state that the appropriate requirements from ASME Code Case N-729-1 are included in the program for loss of material of the upper vessel head.

Clarify whether the Boric Acid Corrosion Program includes consideration of evaluations and repair activities associated with ASME Code Case N-729-1, and if not, provide information on how the loss of material consideration for the reactor vessel closure head associated with this code case is incorporated into another aging management program.

RAI 3.1.2.2-1

LRA Table 3.1.2-2, Row No. 204, addresses CASS reactor vessel internal plenum cylinder reinforcing plates exposed to borated reactor coolant with neutron fluence. The applicant related referenced LRA Table 1 item 3.1.1-80 and GALL Report item IV.B4-4 for this component, which indicates that the component is subject to reduction in fracture toughness due to thermal aging and neutron irradiation embrittlement. The applicant stated that this aging effect is managed by the PWR Reactor Vessel Internals Program.

LRA Section B.2.32 states that the PWR Reactor Vessel Internals Program is based on the examination requirements provided in EPRI Topical Report 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Rev. 0)," along with the implementation guidance described in NEI 03-08.

The staff reviewed MRP-227, Rev. 0, Table 3-1, which lists the reactor vessel internal components of B&W-designed PWRs that require further evaluation for categorization and aging management strategy development. MRP-227, Table 3-1 also lists the aging mechanisms applicable to the vessel internals of B&W plants. In addition, MRP-227, Tables 4-1 and 4-4 list the aging effects and examination methods to inspect the "Primary" and "Expansion" components, respectively, of B&W plants.

The staff noted that MRP-227, Rev. 0, Table 3-1, 4-1 or 4-4 does not specifically address the reduction in fracture toughness of the CASS plenum cylinder reinforcing plate. Therefore, it is not clear to the staff how the applicant will manage the reduction in facture toughness due to thermal aging and neutron irradiation embrittlement of the CASS plenum cylinder reinforcing plate.

Describe and justify how the CASS plenum cylinder reinforcing plate will be managed for reduction in facture toughness by the PWR Reactor Vessel Internals Program.

RAI 3.1.2.2.1-1

The following AMR line items discussed in LRA Section 3.1 credit a time limited aging analysis (TLAA) to manage cumulative fatigue damage:

- LRA Table 3.1.2-4, Row No. 67 addresses the nickel alloy secondary side – auxiliary feedwater pumps (AFW) thermal sleeve and AFW header transition section for cracking due to fatigue.

- LRA Table 3.1.2-4, Row No. 92 addresses the nickel alloy secondary side – main feedwater (MFW) spray head for cracking due to fatigue.
- LRA Table 3.1.2-3, Row No. 164 addresses the steel pressurizer support plate assembly for cracking due to fatigue.
- LRA Table 3.1.2-4, Row No. 84 addresses the steel secondary side – MFW header support plate and gusset for cracking due to fatigue by crediting a TLAA.
- LRA Table 3.1.2-4, Row No. 86 addresses the steel secondary side – MFW header for cracking due to fatigue.
- LRA Table 3.1.2-4, Row No. 110 addresses the steel secondary side – pipe cap for cracking due to fatigue.

For the AMR line items listed above, the staff reviewed LRA Section 4.3 "Metal Fatigue," and it was not clear to the staff which specific TLAA is being credited to manage the cumulative fatigue damage. The staff was not able to confirm if there is a TLAA for components identified by the AMR line items listed above.

The staff requests the following information:

- Clarify the fatigue TLAA that is being credited to manage cumulative fatigue damage for the components identified by the AMR line items in LRA Table 3.1.2-4, Row No. 67, 84, 86, 92 and 110; and LRA Table 3.1.2-3, Row No. 164.
- If the fatigue TLAA for these components are not discussed in LRA Section 4, justify why the TLAA was not identified and dispositioned in accordance with 10 CFR 54.21(c)(1). In lieu of a justification, amend LRA Section 4 to include these fatigue TLAAs, including the disposition in accordance with 10 CFR 54.21(c)(1) and any information that supports this disposition (e.g. cumulative usage factor (CUF) values).

RAI 3.2.2.1.26-1

In LRA Table 3.2.2-1, Row Nos. 26 and 28; Table 3.2.2-2, Rows 20 and 35; Table 3.3.2-1, Rows 76, 77, 78, 79, 80, 84, 88, and 91; Table 3.3.2-4, Row 159; Table 3.3.2-5, Row 60; Table 3.3.2-8, Row 43; Table 3.3.2-12, Row 42; Table 3.3.2-14, Row 25; Table 3.3.2-26, Rows 76 and 83; Table 3.3.2-27, Row 38; Table 3.3.2-30, Row 31; and Table 3.4.2-2, Row 8, the applicant addressed a number of material, environment, aging effect/mechanism combinations as either Generic Note G or H, and assigned only the One-Time Inspection Program. The current staff position, in the GALL Report, is that a more in-depth, periodic inspection program such as the Inspection of Internal Surfaces in Miscellaneous Piping Program or the External Surfaces Monitoring of Mechanical Components Program should be used to manage the aging effect/mechanisms such as loss of material, cracking, or reduction in heat transfer for these component/material/environment combinations.

Consistent with the GALL Report, one-time inspections are appropriate for managing loss of material where environments are consistent with time such as the fuel oil, lube oil, and water chemistry programs. Where environments may not be consistent with time, such as indoor air or outdoor air, the GALL Report recommends the performance of periodic inspections since a

single inspection may not reflect, or predict, the existence of future degradation. Therefore, it is unclear why the applicant has selected the One-Time Inspection Program to manage the various aging effects instead of a program that conducts periodic inspections.
The staff requests the following information:

1. Given that the One-Time Inspection Program may not be an effective program for managing the aging effects associated with the Table 2 line items above, provide details as to how aging will be managed for these material and environment combinations.

2. Provide an assessment of those Table 2 AMR line items containing similar material, environment, and aging effect combinations that might be similarly affected, and revise these line items to ensure an appropriate aging management program.

RAI 3.2.2.2.1-1

LRA Sections 3.2.2.2.1, 3.3.2.2.1 and 3.4.2.2.1 state that fatigue is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The evaluations of the fatigue TLAAs are addressed in LRA, Section 4.

LRA Section 4.3.3.1 discusses the TLAAs associated with fatigue of non-Class 1 piping and in-line components and states that these TLAAs will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The staff reviewed AMR results in the associated LRA Tables (3.x.2-y) in LRA Sections 3.2, 3.3 and 3.4, and noted that they did not include the applicable AMR line items for the TLAAs associated with fatigue of non-Class 1 piping and in-line components. It is not clear to the staff why the components analyzed for cumulative fatigue damage by the TLAAs discussed in LRA Section 4.3.3.1 are not included as AMR line items in LRA Sections 3.2, 3.3 and 3.4.

Justify that AMR line items associated with the TLAAs for fatigue of non-Class 1 piping and in-line components do not need to be included in LRA Section 3.2, 3.3 and 3.4, as applicable. In lieu of a justification, revise the applicable LRA Tables (3.x.2-y) in LRA Sections 3.2, 3.3 and 3.4, to include the AMR line items that address cumulative fatigue damage for non-Class 1 piping and in-line components.

RAI 3.2.2.3.4-2

In LRA Tables 3.2.2-4, 3.2.2-5, 3.3.2-12, 3.3.2-17, and 3.3.2-30, the applicant stated that for stainless steel piping, strainer bodies, strainer screens, tanks, tubing, and valve bodies exposed either externally or internally to air or air-outdoor, there is no aging effect and no AMP is proposed. In LRA Table 3.0-1, the applicant equated the environment of "air" to the GALL Report environments of "air-indoor (uncontrolled)" and "moist air or condensation (internal)."

The GALL Report, Revision 2, contains line items for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air (Tables V.D1, VII.D, and VII.H2), and stainless steel piping, piping components, piping elements internally exposed to condensation (Table VII.D). The GALL Report suggests that such components may be subject to cracking and loss of material based on the environmental conditions applicable to the plant. If so, the GALL Report recommends periodic visual inspections to detect signs of aging.

Outdoor air environments (and associated indoor air environments) likely to cause loss of material and/or cracking include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within one-half mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources.

Provide justification as to why air or air-outdoor will not induce loss of material and/or cracking in stainless steel components at Davis-Besse. In addition, state how aging of stainless steel components will be managed if it is determined that loss of material and/or cracking cannot be ruled out as an aging effect requiring management for stainless steel components.

RAI 3.2.2.2.3.6-1

SRP-LR Table 3.2-1, item 8, states that loss of material from pitting and crevice corrosion could occur for stainless steel components exposed to internal condensation and a plant-specific AMP should be used to ensure that the aging effect is adequately managed. The current staff position is reflected in SRP-LR, Revision 2, Table 3.2-1, item 48, and the GALL Report Revision 2, items V.A.EP-81 and V.D1.EP-81, which recommend that aging in a condensate environment in the engineered safety features systems be managed by AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The GALL Report, Revision 2, Table IX.D, states that condensation is considered to be "raw water" due to the potential for surface contamination. In LRA Table 3.2.1, item 3.2.1-08, the applicant stated that this aging effect will be managed by the One-Time Inspection Program.

It is not clear to the staff how a one-time inspection will be adequate to manage pitting and crevice corrosion of stainless steel components exposed to internal condensation. A one-time inspection is typically used to confirm the insignificance of an aging effect when the aging effect is not expected to occur, the aging effect is expected to progress very slowly, or the characteristics of the aging effect include a long incubation period. The GALL Report Revision 2 recommends that aging in a condensation environment be managed in a manner consistent with a raw water environment, in which periodic inspections are used to ensure that loss of material is adequately managed.

State why a one-time inspection program is used rather than a program with periodic inspections to detect loss of material in stainless steel components exposed to internal condensation, or propose an AMP that includes periodic inspections for pitting and crevice corrosion.

RAI 3.2.2.2.6-1

SRP-LR, Section 3.2.2.2.6, is associated with Table 3.2-1, item 3.2.1-12, and addresses loss of material due to erosion for stainless steel miniflow orifices in high-pressure safety injection pump minimum flow lines. The SRP-LR references LER 50-275/94-023 which documents operating experience where extended use of a centrifugal high pressure safety injection pump for normal charging caused erosion in the miniflow orifice and affected the ability of the pump to perform its intended function. The SRP-LR recommends that a plant-specific AMP be evaluated for erosion of the orifice, and SRP-LR Appendix A.1.2.3.4 states that for a plant-specific program detection of aging effects should occur before there is a loss of the structure's or component's intended function(s).

In LRA Table 3.2.1, item 3.2.1-12, the applicant stated that this item is not applicable, and provides justification by stating that the high-pressure injection pump is not used for normal charging and that normal charging is provided by the makeup pump. However, the discussion continues by stating that loss of material due to erosion in the high-pressure injection and makeup pump miniflow recirculation orifices is addressed in item 3.2.1-49. LRA Section 3.2.2.2.6 contains similar information as discussed in item 3.2.1-12, and adds that the high-pressure injection pump is normally in standby. In this section, the applicant then stated that loss of material due to erosion in the makeup pump and high pressure injection pump miniflow recirculation orifices is managed by the PWR Water Chemistry Program through periodic monitoring and control of contaminants, and that the One-Time Inspection will provide verification of the effectiveness of the PWR Water Chemistry Program to manage loss of material.

LRA Table 3.2.1, item 3.2.1-49, which is cited in item 3.2.1-12, only addresses loss of material due to pitting and crevice corrosion and does not address loss of material due to erosion. It is not clear whether loss of material due to erosion is an aging effect applicable to the orifice in the minimum flow line for the high-pressure injection pump, or if this aging effect is not applicable to this component because the pump is normally in standby. If the aging effect is applicable, then it is not clear whether the One-Time Inspection proposed for managing the aging effect/mechanism of loss of material due to erosion would include a one-time examination of an orifice subject to normal flow and potential erosion (e.g., the high pressure makeup pump), or whether the orifices would be included as part of a sampling of a pipe component population (not orifices) where erosion would be a less likely mechanism to cause loss of material.
The staff requests the following information:

1. Clarify whether loss of material due to erosion is an aging effect expected to occur, and whether this aging effect is being managed for the high pressure injection pump that is normally in standby.

2. If this aging effect is expected to occur and is being managed, clarify whether the proposed One-Time Inspection to manage loss of material due to erosion will examine orifices of similar material and environments that routinely have flow through them.

RAI 3.2.2.3.4-1

In LRA Tables 3.2.2-4 and 3.3.2-12, the applicant stated that for aluminum valve bodies and flame arrestors exposed to air-outdoor (external), there is no aging effect and no AMP is proposed.

In the GALL Report, Revision 2, Tables V.E and VII.I, the aging effect of loss of material due to pitting and crevice corrosion is identified for aluminum piping, piping components and piping elements externally exposed to outdoor air. GALL AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is recommended as a suitable program to manage the aging effect/mechanism (AEM) of loss of material due to pitting and crevice corrosion. In addition, the staff notes that corrosion of aluminum in the passive range is usually manifested by random formation of pits (Ref: Metals Handbook, Volume 13, Corrosion).

Provide justification as to why air-outdoor (external) will not induce loss of material in aluminum alloy components. If it is determined that loss of material due to pitting and crevice corrosion cannot be ruled out as an AEM, please state how aging of aluminum alloy components will be managed.

RAI 3.2.2.3.4-2

In LRA Tables 3.2.2-4, 3.2.2-5, 3.3.2-12, 3.3.2-17, and 3.3.2-30, the applicant stated that for stainless steel piping, strainer bodies, strainer screens, tanks, tubing, and valve bodies exposed either externally or internally to air or air-outdoor, there is no aging effect and no AMP is proposed. In LRA Table 3.0-1, the applicant equated the environment of "air" to the GALL Report environments of "air-indoor (uncontrolled)" and "moist air or condensation (internal)."

The GALL Report, Revision 2, contains line items for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air (Tables V.D1, VII.D, and VII.H2), and stainless steel piping, piping components, piping elements internally exposed to condensation (Table VII.D). The GALL Report suggests that such components may be subject to cracking and loss of material based on the environmental conditions applicable to the plant. If so, the GALL Report recommends periodic visual inspections to detect signs of aging.

Outdoor air environments (and associated indoor air environments) likely to cause loss of material and/or cracking include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within one-half mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources.

Provide justification as to why air or air-outdoor will not induce loss of material and/or cracking in stainless steel components at Davis-Besse. In addition, please state how aging of stainless steel components will be managed if it is determined that loss of material and/or cracking cannot be ruled out as an aging effect requiring management for stainless steel components.

RAI 3.3.1.39-1

GALL Report Revision 1, Volume 1, Table 3, item 39 and GALL Report Revision 2, item VII.A2.A-97 states that stainless steel spent fuel storage racks exposed to treated water greater than 60°C (140°F) are susceptible to SCC and should be managed by the Water Chemistry Program. LRA Table 3.3.1 indicates that item 3.3.1-39 is not applicable because it only will occur for BWR plants. LRA Table 3.5.2-2 also indicates that stainless steel spent fuel storage racks exposed to treated borated water is only susceptible to loss of material.

The applicant's aging management review result is not consistent with the GALL Report indicating that cracking due to SCC is an aging effect requiring management for the stainless steel spent fuel storage racks exposed to treated water greater than 60°C (140°F).

Justify why the cracking due to SCC is not an aging effect requiring management for the stainless steel spent fuel storage racks. If it is determined that the spent fuel storage racks are susceptible to SCC under their exposure conditions, provide additional information on how cracking due to SCC will be managed for the components during the period of extended operation.

RAI 3.3.1.49-1

SRP-LR, Table 3.3-1, item 49, recommends that stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed cycle cooling water be managed by the Closed-Cycle Cooling Water System Program for loss of material due to microbiologically influenced corrosion. LRA Table 3.3.1, item 3.3.1-49, states that this aging effect is not applicable because loss of material due to microbiologically influenced corrosion is not identified as an aging effect requiring management for stainless steel heat exchanger components that are exposed to closed cycle cooling water.

It is not clear to the staff why the applicant does not consider loss of material due to microbiologically influenced corrosion to be an applicable aging affect for stainless steel heat exchanger components exposed to closed cycle cooling water.

State why loss of material due to microbiologically influenced corrosion is not an applicable aging effect for stainless steel heat exchanger components exposed to closed cycle cooling water, or propose an AMP to manage this aging effect.

RAI 3.3.1.54-1

SRP-LR Table 3.3-1, item 54 addresses stainless steel compressed air system piping, piping components, and piping elements exposed to internal condensation. The SRP-LR item recommends GALL AMP XI.M24, "Compressed Air Monitoring," to manage loss of material due to pitting and crevice corrosion. GALL AMP XI.M24 includes visual inspections, leakage testing, and air quality monitoring to manage loss of material for this component group.

LRA Table 3.3.1, item 3.3.1-54 addresses stainless steel tubing, piping, filter housings, pump casings, tanks, orifices and valve bodies exposed to internal condensation which are being managed for loss of material due to pitting and crevice corrosion. The LRA credits the One-Time Inspection Program to manage aging for stainless steel tubing in the instrument air system and cites generic note E. The applicant's One-Time Inspection Program includes one-time inspections of a sample of components in the program.

It is not clear to the staff how the applicant's One-Time Inspection Program, which does not include periodic inspections or preventive measures, is adequate to manage loss of material for stainless steel components exposed to internal condensation in the instrument air system, given that the GALL Report recommends periodic inspections, leakage testing, and air quality monitoring to manage the aging effect.

Explain why a one-time inspection is an acceptable alternative to periodic inspections and air quality monitoring to manage loss of material due to pitting and crevice corrosion for these components.

RAI 3.3.1.68-1

SRP-LR Table 3.3-1, items 3.3.1-68, 3.3.1-69, and 3.3.1-70, address steel, stainless steel, and copper alloy piping, piping components, and piping elements exposed to raw water and recommend GALL AMP XI.M27, "Fire Water System," to manage loss of material. GALL AMP XI.M27 includes flow testing and wall thickness evaluations using either non-intrusive or visual examination techniques to manage loss of material. GALL AMP XI.M27 recommends that the visual inspections be performed on a representative number of locations on a reasonable basis, and be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the pipe as it applies to design flow.

LRA Table 3.3.1, items 3.3.1-68, 3.3.1-69, and 3.3.1-70, state that the Collection, Drainage, and Treatment Components Inspection Program will be used to manage loss of material for steel, stainless steel, and copper alloy components exposed to raw water in the fire protection (diesel) and station plumbing, drains, and sumps systems. The Collection, Drainage, and Treatment Components Inspection Program includes opportunistic visual inspections for loss of material, cracking, and reduction of heat transfer. The visual inspections in the Collection, Drainage, and Treatment Components Inspection Program are not required to be performed on a representative number of locations on a reasonable basis, and do not state that they are capable of detecting wall thickness to ensure against catastrophic failure or the inner diameter of the pipe as it applies to design flow.

It is not clear to the staff how the Collection, Drainage, and Treatment Components Inspection Program is sufficient to manage loss of material for these components given that the program only includes opportunistic visual inspections.

Provide technical justification for using the Collection, Drainage, and Treatment Components Inspection Program to manage loss of material for the AMR items associated with LRA Table 3.3.1, items 3.3.1-68, 3.3.1-69, and 3.3.1-70.

RAI 3.3.1.74-1

The SRP-LR, Revision 2, Table 3.3-1, items 52 and 53, state that for steel cranes – rails exposed to air-indoor uncontrolled (external) the GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," should be used to manage the aging effects/mechanisms of loss of material due to general corrosion and loss of

material due to wear. In addition, GALL AMP XI.M23 states that the program manages the effects of wear on the rails in the rail system.
In LRA Table 3.3.1, item 3.3.1-74, the applicant addressed steel cranes – rails exposed to air–indoor uncontrolled (external) that are subject to loss of material due to wear, and stated that this aging concern is not applicable because loss of material due to wear is not identified as an aging effect requiring management. LRA Table 3.5.2-1, Row 9, Table 3.5.2-2, Row 10, and Table 3.5.2-3, Row 2, state that steel cranes – rails components exposed to air–indoor uncontrolled (external) are being managed for loss of material due to general corrosion, but are not managed for loss of material due to wear.

LRA Section B.2.10, "Cranes and Hoists Inspection Program," is stated to be an existing Davis-Besse program that is consistent with GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." In this same section, the applicant stated, "[t]he inspections monitor structural members for signs of corrosion and wear.

The LRA appears to provide contradictory information in regard to its consideration of loss of material due to wear as an applicable aging mechanism for steel cranes – rails exposed to air–indoor uncontrolled (external). In addition, the LRA does not provide sufficient information to justify why loss of material due to wear is not an applicable aging mechanism for steel cranes - rails.

Clarify whether the steel cranes – rails exposed to air–indoor uncontrolled (external) are being managed for loss of material due to wear. If this aging mechanism is being managed, provide additional information on how it will be managed during the period of extended operation. If loss of material due to wear is not being managed for these components, provide justification for not managing this aging mechanism. Additionally, if loss of material due to wear is not being managed for these components, the staff would consider this to be an Exception to the recommendations of GALL AMP XI.M23 requiring an appropriate justification as to why loss of material due to wear would not be of concern.

RAI 3.3.1.75-1

The SRP-LR Table 3.3-1, item 3.3.1-75, states that elastomer seals and components exposed to raw water are affected by hardening and loss of strength due to elastomer degradation, and loss of material due to erosion. The GALL Report recommends the use of the Open-Cycle Cooling Water System to manage this aging effect. In the LRA, the applicant stated that this aging effect will be managed by the One-Time Inspection Program. A one-time inspection is typically used to provide assurance that aging has either not manifested or that the aging is sufficiently slow that it does not require management.

It is not clear to the staff how a one-time inspection will be adequate to detect hardening and loss of strength due to elastomer degradation, and loss of material due to erosion of elastomer seals and components exposed to raw water.

Provide justification for using a One-Time Inspection Program rather than a program such as the Open-Cycle Cooling Water System program, which conducts periodic inspections to manage the aging of the elastomer materials exposed to raw water.

RAI 3.3.1.80-1

For LRA Table 3.3.1, item 3.3.1-80, which addresses stainless steel and copper alloy piping components exposed to raw water that are being managed for loss of material due to pitting, crevice, and microbiologically influenced corrosion, the applicant stated that this item is not applicable. Instead, the applicant referred to LRA Table 3.3.1, items 3.3.1-78 or 3.3.1-79. Item 3.3.1-78 addresses the same components made of comparable materials exposed raw water that are being managed for loss of material due to pitting and crevice corrosion. Item 3.3.1-79 addresses the same components made of the same material that are being managed for loss of material due to pitting and crevice corrosion, and fouling of stainless steel components exposed to raw water. However, neither of these referenced items address loss of material due to microbiologically influenced corrosion.

The applicant did not appear to consider loss of material due to microbiologically influenced corrosion as an aging mechanism in the auxiliary systems for stainless steel and copper alloy piping components exposed to raw water. However, the applicant did not provide sufficient information in the LRA to justify its position.

Clarify whether the stainless steel and copper alloy piping, piping components, and piping elements exposed to raw water are being managed for loss of material due to microbiologically influenced corrosion. If microbiologically influenced corrosion is not being managed for these components, provide justification for not needing to manage this aging mechanism. If this aging mechanism is being managed, provide the additional information on how it will be managed during the period of extended operation.

RAI 3.3.1.85-1

SRP-LR, Table 3.3-1, item 85, recommends that gray cast iron piping, piping components, and piping elements exposed to soil, raw water, treated water, or closed-cycle cooling water be managed by the Selective Leaching of Materials Program for loss of material due to selective leaching. In LRA Table 3.3.2-32, the applicant did not include loss of material due to selective leaching as an applicable aging effect for the gray cast iron heat exchanger shell in the startup feed pump lube oil cooler (DBE30) exposed to closed-cycle cooling water in the turbine plant cooling water system. For the gray cast iron heat exchanger channel in the same cooler, the applicant manages for loss of material due to selective leaching, citing LRA Table 3.3.1, item 3.3.1-85.

It is not clear to the staff why the applicant does not include selective leaching as an aging effect for the gray cast iron heat exchanger shell in the startup feed pump lube oil cooler (DBE30) exposed to closed-cycle cooling water in the turbine plant cooling water system.

State why loss of material due to selective leaching is not an applicable aging effect for the gray cast iron heat exchanger shell in the startup feed pump lube oil cooler (DBE30), or propose an AMP to manage this aging effect.

RAI 3.3.2.-1

In LRA Table 3.3.2-3, the applicant stated that for copper alloy bolting exposed to air with steam or water leakage (external), there is no aging effect requiring management and no AMP is proposed.

The staff reviewed the associated items in the LRA and noticed that there could be a potential for loss of material due to pitting and crevice corrosion and cracking depending on the potential contaminants because the GALL Report states that copper-zinc alloys greater than 15 percent zinc are susceptible to SCC, selective leaching (except for inhibited brass), pitting and crevice corrosion. Additional copper alloys, such as aluminum bronze, greater than 8 percent aluminum, also may be susceptible to SCC or selective leaching.

Provide justification as to why the specific environment, air with steam or water leakage (external) will not induce loss of material or cracking in copper alloy bolting.

RAI 3.3.2.-2

In LRA Tables 3.3.2-1, 3.3.2-12, 3.3.2-14, and 3.3.2-30, the applicant stated that copper alloy and copper alloy (Zn greater than 15 percent) and copper alloy heat exchanger tubes – aftercooler and radiator, piping, tubing, valve bodies, spray nozzles exposed to air-outdoor (external/internal) there is no aging effect and no AMP is proposed.

The staff reviewed the associated items in the LRA and found that loss of material due to cracking could occur in copper alloy components exposed to air-outdoor (external/internal) depending on atmospheric contaminants in the environment. The GALL Report states that condensation on the surfaces of systems at temperatures below the dew point is considered "raw water" due to the potential for internal or external surface contamination. Copper alloys with greater than 15 percent zinc or greater than 8 percent aluminum exposed to a raw water environment may be susceptible to SCC or selective leaching.

Provide justification as to why the specific environment, air-outdoor (external/internal) will not induce loss of material due to cracking or selective leaching in copper alloys.

RAI 3.3.2.-3

In LRA Tables 3.3.2-15, 3.3.2-17 and 3.3.2-30, the applicant stated that copper alloy (Zn greater than 15 percent) and copper alloy tubing and valve bodies exposed to air-indoor uncontrolled (external) and/or air (internal) there is no aging effect and no AMP is proposed.
The staff noted that in LRA Table 3.0-1, Process Environments, air is defined to be an air environment containing some amount of moisture or contaminants, this includes air - indoor uncontrolled. The staff reviewed the associated items in the LRA and found that loss of material and cracking could occur in copper alloy components exposed to air (internal/external) depending on the contaminants and moisture. The GALL Report states that condensation on the surfaces of systems at temperatures below the dew point is considered "raw water" due to the potential for internal or external surface contamination. Copper alloys with greater than

15 percent zinc or greater than 8 percent aluminum exposed to a raw water environment may be susceptible to SCC or selective leaching.

Provide justification as to why the specific environments, air indoor-uncontrolled (external) and/or air (internal) will not induce loss of material due to selective leaching or cracking in copper alloys.

RAI 3.3.2.1-1

The GALL Report indicates that copper alloys greater than 15 percent zinc exposed to raw waster are susceptible to selective leaching. In LRA Table 3.3.2-1, the applicant stated that copper alloy greater than 15 percent zinc heat exchanger tubes exposed to raw water are being managed for cracking by the Open-Cycle Cooling Water Program. However, the applicant did not indicate that this component is being managed for selective leaching.

It is not clear to the staff why copper alloy greater than 15 percent zinc heat exchanger tubes exposed to raw water are not being managed for selective leaching.

Provide technical justification for not managing copper alloys greater than 15 percent zinc exposed to raw water for selective leaching. If it is determined that selective leaching is an applicable aging effect, indicate what program will be used to manage this aging effect.

RAI 3.3.2.18-1

SRP-LR Section A.1.2.1, item 7 states the determination of applicable aging effects is based on degradations that have occurred and those that potentially could cause structure and component degradation. The SRP-LR also states that the materials, environment, stresses, service conditions, operating experience, and other relevant information should be considered in identifying applicable aging effects.

LRA Table 3.3.2-18, Row Nos. 137 and 138, state that stainless steel "Tank – Purification demineralizers (DB-T5-1, 2, & 3)" exposed to treated borated water, is subject to loss of material. These components will be managed by the PWR Water Chemistry Program and One-Time Inspection Program. LRA Table 3.3.2-18, Row Nos. 79-80 and 81-82, state that stainless steel piping exposed to treated borated water > 60 °C (> 140 °F) is subject to cracking and loss of material, respectively. These components are managed by the PWR Water Chemistry Program and One-Time Inspection Program. Similarly, there are other stainless steel components in LRA Table 3.3.2-18 that are only being managed for loss of material.

Licensee Event Report (LER) 1998-002-01 dated November 7, 2003, addresses an event associated with demineralizer resin blockage of the let down line in the makeup and purification system. Due to corrosion in the Purification Demineralizer #3 internal screen, resin was released into the downstream piping. Subsequent inspections of the demineralizer revealed that its internals had degraded, which resulted in demineralizer resin being transported into the filter housings. The screen mesh at the bottom of the demineralizer failed due to extensive pitting corrosion and material deficiencies which allowed the resin breakthrough. A metallurgical analysis indicated that sulfur compounds, which caused a low pH, were likely the cause of the pitting. The likely source of the sulfur compounds was attributed to the degradation of the cation resin beads due to the partially spent condition and extended radiation exposure of the resin.

LER 1998-002-01 indicates that the degradation of the resin beads in Purification Demineralizer #3 resulted in releases of sulfur compounds that caused the extensive pitting of the demineralizer internal screen and the breakthrough of the resin beads to the downstream piping. The staff noted that that a release of sulfur compounds can facilitate stress corrosion cracking. Therefore the staff needs clarification as to whether this operating experience has been adequately evaluated and whether stress corrosion cracking in the demineralizer tanks and their downstream piping needs to be managed.

The staff requests the following information:

1. Describe whether or not the stainless steel components in the makeup and purification system that were previously exposed to sulfur compounds have experienced stress corrosion cracking. In addition, justify why cracking due to stress corrosion cracking is not an aging effect requiring management for the stainless steel demineralizer tanks, including internal screens, and filter housing.

2. If the piping has experienced stress corrosion cracking, justify why the One-Time Inspection Program is adequate to manage cracking due to stress corrosion cracking of the piping rather than a program that includes periodic inspections.

RAI 3.3.2.2.3.3-1

The GALL Report, Revision 1, Table 3, item 6, states that cracking due to stress corrosion cracking could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. In addition, item VII.H2.AP-128 of the GALL Report, Revision 2, recommends the use of GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage cracking due to stress corrosion cracking of stainless steel diesel engine exhaust piping, piping components and piping elements.

In LRA Section 3.3.2.2.3.3, the applicant stated that cracking due to stress corrosion cracking could occur in stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. The applicant further stated that flexible connections and tubing of the diesel exhaust piping are stainless steel, and other piping components are steel, and cracking due to stress corrosion cracking for stainless steel diesel engine exhaust piping components, though it is not expected to occur, will be managed by the One-Time Inspection Program.

Stress corrosion cracking is a potential aging effect for stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust as indicated in the GALL Report, Revision 1 and Revision 2. In addition, GALL Report Revision 2 specifies the use of XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," program which is a periodic inspection program to manage the aging effect. However, the applicant credits the One-Time Inspection program to manage the aging effect.

Provide technical justification to describe why the One-Time Inspection Program is adequate to monitor the cracking due to stress corrosion cracking aging effect on diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust during the period of extended operation.

RAI 3.3.2.2.7.3 -1

The GALL Report, Revision 1, Table 3, item 18, states that loss of material due to general (steel only), pitting, and crevice corrosion could occur for steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust. In addition, item VII.H2.AP-104 of the GALL Report, Rev. 2, recommends the use of GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," for steel and stainless steel diesel exhaust piping, piping components, and piping elements.

In LRA Section 3.3.2.2.7.3, the applicant stated that loss of material due to general (steel only), pitting, and crevice corrosion could occur for steel and stainless steel diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust. The applicant further stated that at Davis-Besse, loss of material due to general (steel only), pitting, and crevice corrosion for steel and stainless steel diesel exhaust piping, piping components, and piping elements that are exposed to diesel exhaust will be managed by the One-Time Inspection program.

Loss of material due to general (steel only), pitting, and crevice corrosion is a potential aging effect for steel and stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust as indicated in the GALL Report, Rev 1 and Rev 2. In addition, GALL Report, Rev. 2, specifies the use of XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," program which is a periodic inspection program to manage the aging effect. However, the LRA credits the One-Time Inspection program to manage the aging effect.

Provide technical justification to describe why the One-Time Inspection Program is adequate to manage the loss of material due to general (steel only), pitting, and crevice corrosion aging effect on diesel exhaust piping, piping components, and piping elements exposed to diesel exhaust during the period of extended operation.

RAI 3.3.2.2.13-1

In LRA Section 3.3.2.2.13, the applicant stated that wear of elastomer seals and components exposed to air is not identified as an aging effect requiring management at Davis-Besse. It also stated that loss of material due to wear is the result of relative motion between two surfaces in contact. However, wear occurs during the performance of an active function; as a result of improper design, application, or operation; or to a very small degree with insignificant consequences. GALL Report Section IX.F defines wear as the removal of surface layers due to relative motion between two surfaces or under the influence of hard abrasive powder. The GALL Report further states that wear occurs in parts that experience intermittent relative motion or frequent manipulation.

The applicant based its conclusion that loss of material due to wear was not an aging effect requiring management (AERM) on the fact that wear is an active loss of material mechanism and not on the fact that the elastomeric HVAC seals and components for which wear is plausible are active components or components that are replaced on a qualified or specified frequency. Within the definition of the term "wear" in GALL Report Section IX.F, there are three factors to consider that could cause age-related wear due to the design of the joint, including (a) relative motion between two surfaces, under the influence of hard abrasive particles, (b) frequent manipulation, or (c) in clamped joints where relative motion is not intended but may occur due to a loss of the clamping force.

It is unclear to the staff whether there are any in-scope components that are designed in such a way that they could be impacted by the three age-related factors considered in the definition of wear.

The staff requests the following information:

1. State whether any in-scope elastomeric components which are designed with relative motion that are exposed to an internal or external environment that includes hard abrasive particles.

2. State whether any in-scope elastomeric components that are susceptible to wear that over time, due to their frequent manipulation could challenge the CLB function(s) of the component.

3. State whether any in-scope elastomeric components that have clamped joints where relative motion is not intended but may occur due to a loss of the clamping force over time causing wear that could challenge the CLB function(s) of the component.

4. If an AERM is applicable based on the configurations or aging mechanisms described in items (1) through (3), discuss how the AERM will be managed.

RAI 3.3.2.2.4-1

In LRA Section 3.3.2.2.4.1, the applicant stated that cracking due to SCC and cyclic loading in stainless steel non-regenerative heat exchanger components is managed by the Water Chemistry Program, and the effectiveness of the Water Chemistry Program will be confirmed by the One-Time Inspection Program. The applicant also stated that the One-Time Inspection Program is selected in lieu of eddy current testing of tubes and that temperature and radioactivity monitoring of shell side water is performed by installed instrumentation. The applicant further stated that cracking due to cyclic loading is not identified as an aging effect requiring management for stainless steel heat exchanger components in the associated environment.

The acceptance criteria in SRP-LR Section 3.3.2.2.4, item 1, states that cracking due to SCC and cyclic loading in stainless steel non-regenerative heat exchangers is managed by monitoring and controlling primary water chemistry. The SRP-LR also states that the effectiveness of water chemistry control programs should be verified, because water chemistry controls do not preclude this aging effect. The GALL Report recommends that a plant-specific AMP be evaluated to ensure these aging effects are adequately managed and an acceptable verification program includes temperature and radioactivity monitoring of the shell side water and eddy current testing of tubes.

In LRA Section B.2.30, "One-Time Inspection Program," the applicant stated that a representative sample of the system and component population will be inspected using a variety of nondestructive examination methods, including visual inspection, volumetric inspection, and surface inspection techniques. It further stated that the sample population will be determined by engineering evaluation, and where practical, will be focused on the components considered most susceptible to aging degradation due to time in service, the severity of the operating conditions, and the lowest design margin. However, it is not clear whether the non-regenerative heat exchangers will be included in the sample of components to be inspected, and since eddy current testing of tubes is not used, what inspection techniques will be used.

In addition, the LRA did not provide the bases for the statement that cyclic loading is not identified as an aging effect requiring management for stainless steel heat exchanger components exposed to treated borated water greater than 60°C.

The staff requests the following information:

1. Clarify whether the non-regenerative heat exchangers will be included in the sample of components to be inspected by the One-Time Inspection Program.

2. Describe the nondestructive examination technique that will be used in lieu of eddy current testing of tubes, which will provide verification of the effectiveness of PWR water chemistry to manage cracking due to SCC in stainless steel non-regenerative heat exchanger components.

3. Provide the bases for the statement that cracking due to cyclic loading is not identified as an aging effect requiring management for stainless steel heat exchanger components exposed to treated borated water greater than 60°C.

RAI 3.3.2.3.12-2

In LRA Tables 3.3.2-12, 3.3.2-14, and 3.3.2-15, the applicant stated that for elastomer flexible connections exposed to fuel oil and lubricating oil internal environments, there is no aging effect and no AMP is proposed. The AMR line items cite generic note F. The GALL Report does not address elastomeric materials exposed to fuel oil or lubricating oil.

Given that certain elastomers such as natural rubbers and ethylene-propylene-diene (EPDM) are not resistant to fuel oil or lubricating oil, the staff needs to know the material of construction of the flexible connections to determine if there are no aging effects.

State the materials of construction of the flexible connections exposed to fuel oil and lubricating oil as listed in LRA Tables 3.3.2-12, 3.3.2-14, and 3.3.2-15.

RAI 3.3.2.3.14-1

In LRA Table 3.3.2-14, the applicant identified loss of material and cracking as aging effects for steel bolting exposed to an external environment of raw water. As identified in EPRI NP-5769 and NUREG-1833, loss of pre-load for bolting can occur in any environment.

In LRA Table 3.3.2-14, the applicant did not identify loss of pre-load for steel bolting exposed to an external environment of raw water.

Justify why loss of pre-load is not identified as an aging effect for steel bolting in an environment of raw water.

RAI 3.3.2.3.14-2

In LRA Table 3.3.2-14, the applicant identified cracking as an aging effect for steel bolting and copper alloy greater than 15 percent Zn heat exchanger tubes in an external environment of raw water and credits LRA Section B.2.9, "Collection, Drainage, and Treatment Components Inspection Program," to manage the aging effect using enhanced visual inspections to detect cracking.

It is not clear how the applicant proposes to perform enhanced visual inspections of the bolting and heat exchanger tubes in an external environment of raw water to detect cracking. An external environment of raw water implies that these components will be under water.

Justify how enhanced visual inspections will detect cracking of components under water in an external environment of raw water.

RAI 3.3.2.3.14-3

SRP-LR Revision 2 Table 3.3-1, item 112, recommends that steel piping, piping components, and piping elements exposed to concrete do not need to be age managed, provided that the attributes of the concrete are consistent with ACI 318 or ACI 349 and that plant operating experience indicates no degradation of the concrete. LRA Table 3.3.2-14, item 54 (fire protection system), Table 3.3.2-26, item 56 (service water system), Table 3.3.2-31, item 48 (station plumbing, drains, and sumps system), and Table 3.5.2-12, item 7 (yard structures), state that steel components exposed to concrete do not need to be age managed. LRA Section B.2.39, "Structures Monitoring Program," includes several incidents of operating experience where water leakage through the concrete has occurred.

It is not clear to the staff whether concrete degradation has occurred in the vicinity of in-scope components described in the request such that the steel components would be exposed to water and thus be subject to corrosion.
The staff requests the following information:

1. State whether concrete degradation has occurred such that water may have intruded into the concrete that surrounds the steel components in the fire protection system, service water system, station plumbing, drains, and sumps system, and yard structures.

If water intrusion has occurred, state how the aging of the steel components will be managed.

2. State how the Structures Monitoring Program, or other plant-specific program, will address water intrusion into concrete to ensure that resulting aging of embedded steel components will be effectively managed during the period of extended operation.

RAI 3.3.2.2.4.3-1

SRP-LR Rev. 1 Section 3.3.2.2.4, item 3 states that cracking due to SCC and cyclic loading could occur for stainless steel pump casing for the PWR high-pressure pumps in the chemical and volume control system.

GALL Report Revision 2, item VII.E1.AP-114 addresses cracking due to SCC of the stainless steel high-pressure pump casing in the chemical and volume control system, which is exposed to treated borated water greater than 60°C. It also recommends the Water Chemistry Program and One-Time Inspection Program to manage cracking due to SCC.

GALL Report Revision 2, item VII.E1.AP-115 addresses cracking due to cyclic loading of the stainless steel high-pressure pump casing, which is exposed to treated borated water. It also recommends the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage cracking due to cyclic loading.

By contrast, LRA Section 3.3.2.2.4.3 states that cracking due to stress corrosion cracking and cycling loading is not identified as an aging effect requiring management for the stainless steel pump casing for the high-pressure pumps and is not applicable.

It is not clear to the staff how the applicant concluded that cracking due to stress corrosion cracking and cracking due to cyclic loading are not aging effects requiring management for the stainless steel pump casings for the high pressure pumps. The applicant did not provide sufficient justification for its conclusion.

Justify why neither cracking due to stress corrosion cracking nor cracking due to cyclic loading is an aging effect requiring management for the stainless steel high-pressure pump casing in the makeup and purification system. If it is determined that the stainless steel high-pressure pump casing is susceptible to either cracking due to stress corrosion cracking or cracking due to cyclic loading under the exposure conditions, justify how the aging effect(s) will be managed for the component during the period of extended operation.

RAI 3.3.2.3.12-1

SRP-LR Table 3.3-1, item 14, recommends that steel piping, piping components, and piping elements exposed to lubricating oil be managed by the Lubricating Oil Analysis Program and the One-Time Inspection Program. The GALL Report AMP XI.M39, "Lubricating Oil Analysis Program," element 3 "parameters monitored/inspected" states that, for components with periodic oil changes in accordance with manufacturer's recommendations, a particle count and check for water are performed to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. The updated staff position in the GALL Report, Revision 2 AMP XI.M39, element 4 "detection of aging effects" states that the program recommends sampling and testing of the old oil following periodic oil changes or on a schedule consistent with equipment manufacturer's recommendations or industry standards.

In LRA Table 3.3.2-12, item 21, and Table 3.3.2-14, item 167, the applicant stated that loss of material is not applicable to steel air intake filter bodies exposed to lubricating oil in the diesel generators system. The applicant cited Plant-Specific Note 0325, which states that the aging effects are not applicable due to the regular replacement of the lubricating oil. The staff noted that LRA Table 3.3.2-12, items 19 and 20 (adjacent to item 21 above), state that steel filter bodies exposed to lubricating oil in the emergency diesel generators system are managed for loss of material by the Lubricating Oil Analysis Program and One-Time Inspection Programs.

It is not clear to the staff why the applicant does not consider loss of material to be an applicable aging affect for the steel air intake filter bodies exposed to lubricating oil. The GALL Report AMP XI.M39, "Lubricating Oil Analysis Program," takes into account that periodic oil changes will occur and recommends that periodic checks for contamination be performed to ensure that the environment does not become conducive to loss of material. It is also not clear why adjacent steel filter body line items in the emergency diesel generators system are age managed in a different manner.

State why loss of material is not an applicable aging effect for the steel air intake filter bodies when components have regular replacements of lubricating oil, or propose an AMP(s) to manage the aging effect. Also, state why the steel air intake filter bodies are being age managed in a manner different than that of the adjacent steel filter body line items in the emergency diesel generators system.

RAI 3.4.2.3-1

The GALL Report describes condensation as an environment where there is enough moisture for corrosion to occur. It further recommends the External Surfaces Monitoring AMP to manage the aging effect of loss of material and leakage though periodic visual inspections of the external surfaces of in-scope mechanical components, and monitors external surfaces of metallic components in systems within the scope of license renewal.

In Plant-Specific Note 0408 in LRA Table 3.4.2-3, the applicant stated that, except for the motor-driven feedwater pump and startup feed pump portions of the main feedwater system, the control air supply components associated with the main and start-up control valves, and bolting exposed to air with steam or water leakage, loss of material due to general corrosion is not an aging effect requiring management for the external surfaces of steel components in the main feedwater system that are exposed to an air-indoor uncontrolled environment. In Plant-Specific Note 0408, the applicant further stated that the reason the specified components do not require aging management for loss of material due to general corrosion is because their surface temperatures are greater than 212°F (100°C) and are, therefore, expected to be dry.
Given the plant-specific experience of two extended outages in recent years, it is not clear to the staff how the specified components will remain above 212°F (100°C) throughout their service life

in the period of extended operation, and therefore, not be considered susceptible to loss of material due to general corrosion from condensation on the surfaces of systems.

Provide justification that the temperatures of the external surfaces of the main feedwater system exposed to an "air-indoor uncontrolled" environment will not be below 212°F (100°C) during the period of extended operation. If the external surfaces of the main feedwater system may be exposed temperatures below 212°F (100°C), please state how loss of material due to general corrosion will be managed for the subject components.

RAI 3.4.2.2.5-1

In LRA Sections 3.4.2.2.5.2 and 3.4.2.2.7.3, the applicant stated that loss of material due to pitting and crevice corrosion could occur in gray cast iron and copper alloy heat exchanger components exposed to lubricating oil. In addition, both LRA sections state that loss of material due to selective leaching in these materials is managed by the Lubricating Oil Analysis Program. The associated line items, 3.4.1-12 and 3.4.1-18, both cite Plant-Specific Note 0403 which states that selective leaching is managed by controlling water contamination in the lubricating oil. The staff notes that LRA Section B.2.26, "Lubricating Oil Analysis Program," describes this program as consistent with GALL AMP XI.M39, with no exceptions or enhancements and includes periodic sampling and analysis of lubricating oil to maintain contaminants within acceptable limits. The LRA AMP discusses loss of material due to various mechanisms, but does not specifically cite selective leaching. GALL AMP XI.M33, "Selective Leaching of Materials," recommends visual inspection and hardness measurement or other mechanical examination techniques. Although the LRA shows that the effectiveness of the Lubricating Oil Analysis Program will be verified by the One-Time Inspection Program, the One-Time Inspection Program neither discusses hardness measurements as one of the inspection techniques nor specifically states loss of material due to selective leaching will be considered for the Lubricating Oil Analysis Program.

Since the description of the Lubricating Oil Analysis Program does not state that it manages selective leaching, it is not clear whether the One-Time Inspection Program will verify the effectiveness of the Lubricating Oil Analysis Program for managing loss of material due to selective leaching, for which it is being credited in LRA Sections 3.4.2.2.5.2 and 3.4.2.2.7.3. Since the detection of selective leaching requires specific examinations such as material hardness measurements, chipping, scraping, etc., it was not clear whether these would be performed under the One-Time Inspection Program or under the Selective Leaching Program, which is also a one-time inspection program.

If loss of material due to selective leaching, for line items 3.4.1-12 and 3.4.1-18, is being managed by the Lubricating Oil Analysis Program, then clarify this aspect in the program's description. In addition, confirm that the One-Time Inspection Program, instead of the Selective Leaching Program, will verify the effectiveness of the Lubricating Oil Analysis Program for managing loss of material due to selective leaching.

RAI 3.5.2.1-1

The GALL Report (Revision 2) in Table IX.E lists the standardized aging effects due to associated aging mechanisms used in its AMR tables, Chapters II through VIII. GALL XI.M39 "External Surfaces Monitoring of Mechanical Components" and XI.S7 "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," are the AMPs having de-facto provisions to identify changes in material properties. LRA Tables 3.5.2-1 through 3.5.2-13 show a number of concrete structures or components listing "change in material properties," as an aging effect requiring management and list the Structures Monitoring Program enhanced with ACI 349.3R-96 and ANSI/ASCE 11-90, and the included Water Control Structures Inspection Program, to support the detection of this aging effect. For these line items the applicant uses NEI Generic Note "A," which affirms consistency with NUREG-1801 for both the selected AMP and for each identified item for component, material, environment and aging effect.

It is not clear to the staff what material properties the applicant seeks to detect changes to. It is also not clear to the staff how the "change in material properties aging effect" will be detected, especially when some of the line items are difficult to access or below grade, as shown for example in Table(s):

- 3.5.2-1, Rows 61, 62;
- 3.5.2-2, Rows 65, 66;
- 3.5.2-3, Rows 34, 25.

For structures or structural components, identification of changes in concrete material properties (e.g., compressive, tensile strengths, etc.) requires testing. For detection of aging effects, enhancement of the Structures Monitoring AMP with ACI 349.3R-96 and ANSI/ASCE 11-90 provide guidelines for nondestructive and invasive testing. By contrast EPRI TR-1007933 is a visual examination guide.

The staff requests the following information:

1. For Davis-Besse, explain for the screened class of components and structures why the applicant is concerned with the "change in material properties" and defines this to be an aging effect requiring management.

2. What are the material properties of interest to the applicant and how (what detection techniques) will the applicant detect the anticipated changes?

3. Justify the adequacy of the selections for both properties and techniques.

RAI 3.5.2.2.1.7-1

SRP-LR Revision 1, Section 3.5.2.2.1.7 states that cracking due to stress corrosion cracking of stainless steel penetration sleeves, penetration bellows, and dissimilar metal welds could occur in all types of PWR and BWR containments. LRA Section 3.5.2.2.1.7 states that SCC requires a combination of a corrosive environment, susceptible materials, and high tensile stresses and that; stainless steel must be subject to both high temperature (> 140°F) and an aggressive chemical environment. The applicant also stated that SCC is not an applicable [aging] effect for stainless steel penetration sleeves and bellows because these components are not subject to an aggressive chemical environment. LRA Table 3.5.2-1 for the containment further indicates that the penetration components are exposed to an air-indoor environment.

LRA Section 3.5.2.2.1.10 states that change in material properties due to leaching of calcium hydroxide is an aging effect requiring management for concrete components. This aging effect is applicable at Davis-Besse due to operating experience indicating water leakage (above and below grade). In view of the observed water leakage associated with concrete structures and components, the staff found a need to further clarify whether the applicant's aging management review adequately evaluated the operating experience with the water leakage in its determination that cracking due to SCC is not an applicable aging effect for the containment penetration components.

Justify why the water leakage addressed in LRA Section 3.5.2.2.1.10 is not conducive to stress corrosion cracking of the stainless steel penetration sleeves and bellows. As part of the justification, clarify whether the water leakage has been in contact with the containment penetration components and describe the applicant's operating experience in terms of the occurrence of stress corrosion cracking in the containment penetration components. If stress corrosion cracking has been observed, justify why this aging effect has been determined to be not applicable.

RAI 3.5.2.2.2-1

SRP Table 3.5.1, Item 3.5.1-33 recommends further evaluation for any concrete elements that exceed the specified temperature limits of 150°F general and 200°F local.

LRA Section 3.5.2.2.2.3 notes that several localized areas in the upper regions of the containment internal structures have maximum temperatures exceeding 150°F.

The staff is unclear how concrete, having temperatures above the limits in the SRP Table 3.5.1, Item 3.5.1-33, will be managed during the period of extended operation. The staff requests the following information:

1. Provide a listing of locations where concrete temperature exceeds SRP Table 3.5.1, Item 3.5.1-33 limits for general or local areas.

2. For each of these locations, provide the extent of the region of concrete impacted and the maximum temperature experienced by the concrete.

3. Provide a description of how these locations will be managed during the period of extended operation or an assessment of the impact of the elevated temperature on concrete to demonstrate that the concrete properties have not been adversely impacted.

The staff needs the above information to confirm that the effects of aging such as noted above will be adequately managed so that the intended function of impacted structural members will be maintained consistent with the current licensing basis for the period of extended operation as required by 10 CFR 54.21(a)(3).

RAI 3.5.2.3.1-1

SRP-LR in Section 4.3, titled "Metal Fatigue," states that ASME Section III requires a fatigue analysis for Class 1 components unless allowed by the Code to be exempted under applicable ASME Section III provisions. The SRP-LR also states, in Section 4.6, titled "Containment Liner Plate Metal Containments, and Penetration Fatigue Analysis," subsection 4.6.1.1, titled "Time-Limited Aging Analysis," that specific requirements for fatigue analysis are contained in the design code of reference for each plant. The applicant in the LRA stated that the containment vessel meets the requirements of ASME Section III, Paragraph N-415.1; thereby justifying the exclusion of cyclic or fatigue analyses in the design of the containment vessel. The LRA further states that the containment penetrations are excluded on the basis of N-415.1, Vessels not requiring Analysis for Cyclic Operation. The staff reviewed the USAR and verified that vibrational loads are treated in accordance with ASME Code Section III, paragraph N-415 which precludes fatigue analysis.

LRA Table 3.5.2-1 Aging Management Review Results – Containment, references the GALL Report AMR line item II.A3-4, for cumulative fatigue damage due to cyclic loading of penetration sleeves and bellows made of steel; stainless steel; and dissimilar metal welds for the Containment Vessel. The staff noted that the particular AMR line item is recommended for use only when there is a CLB fatigue analysis.

The staff requests the following information:

1. Does the applicant have a CLB fatigue analysis assessing damage incurred from cyclic loading of penetration sleeves and bellows made of steel; stainless steel; and dissimilar metal welds for the Containment Vessel?

2. If no CLB fatigue analysis exists, explain the apparent contradiction of the AMR Containment Vessel penetrations excluded from fatigue analysis with the II.A3-4, which is recommended only if there is a CLB fatigue analysis.

RAI 3.5.2.3.12-1

The GALL Report (e.g., Item III.B3-7) notes that for steel components providing an intended function of anchorage (e.g., hold down) in an air-indoor uncontrolled or air-outdoor environment loss of material/general and pitting corrosion is an AERM. LRA Table 3.5.2.3-12 states that the wire rope hold down restraints for the emergency diesel generator (EDG) fuel oil tanks subjected to a structural backfill environment do not have an AERM; however, the applicant stated that the Structures Monitoring Program would be used to confirm the absence of aging effects.

The staff is unclear why the wire rope hold down restraints for the EDG fuel oil tanks, subjected to a structural backfill environment, do not have an associated AERM. The staff is also unclear how the Structures Monitoring Program, a visual inspection program can effectively monitor aging of a component in structural backfill.

The staff requests the following information:

1. Explain why loss of material is not an aging effect for the steel restraints in a backfill environment.

2. Explain how the Structures Monitoring Program can monitor aging of components in structural backfill.

RAI 3.5.2.3.12-2

LRA Table 3.5.2.3-12 states that the galvanized steel wave protection dike corrugated pipe casings and carbon steel wave protection dike piles exposed to structural backfill are managed for loss of material by the Structures Monitoring Program. The Wave Protection Dike corrugated pipe casings and Wave Protection Dike piles buried in the wave protection dikes can be exposed to groundwater since the corrugated pipe casings are located below the site groundwater elevation.

Since the Structures Monitoring Program in large measure is visual and the components are located below the site groundwater elevation, the staff is unclear how the Structures Monitoring Program will be utilized to manage loss of material during the period of extended operation.

Explain how the Structures Monitoring Program will be utilized to manage loss of material during the period of extended operation.

RAI 3.5.2.3.13-1

LRA Table 3.5.2-13, Aging Management Review Results – Bulk Commodities, includes lines for fiberglass containment penetration insulation and for calcium silicate or fiberglass piping and mechanical equipment insulation exposed to indoor or outdoor air. In the LRA, the applicant states that there are no aging effects for these material and environment combinations requiring age management and no aging management program is proposed. For the applicable AMR line items, the applicant cites generic note J, indicating that neither the component nor the material and environment combination is evaluated in the GALL Report. The staff noted that mechanical equipment insulation is not addressed in the GALL Report.

In LRA Section 2.1.2.6, the applicant states that thermal insulation may be credited with a specific function (such as in-room heat-up analyses and for structural fire barriers) or be affixed to mechanical components and have potential to fall on, block, or obstruct safety-related components. The applicant also states that insulating materials that function to limit heat transfer, perform a fire barrier function, or must maintain their integrity to prevent interactions with safety-related components are within the scope of license renewal. The LRA treats the fiberglass containment penetration insulation and calcium silicate or fiberglass piping and mechanical equipment insulation exposed to indoor or outdoor air as bulk commodities but does not identify specific locations or applications associated with in-scope insulation components.

The staff notes that in a dry environment of indoor or outdoor air, without potential for water leakage, spray, or condensation, fiberglass and calcium silicate are expected to be inert to environmental effects. However, in moist environments, calcium silicate has been found to degrade. In addition, both fiberglass and calcium silicate insulation have the potential for prolonged retention of any moisture to which they are exposed; prolonged retention of moisture may increase thermal conductivity, thereby degrading the insulating characteristics, and also could accelerate the aging of insulated components. The staff noted that the LRA's description of insulation materials includes aluminum jacketing which, if properly installed, provides protection from ambient moisture for the heat-resistant insulating materials.

For those insulation components in LRA Table 3.5.2-13 with a function to limit heat transfer, state how the configuration of the jacketing ensures that it is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams) such that aging management is not required.

RAI 3.6-1

In LRA Table 3.6-1, Item 3.6.1-09 metal enclosed bus – enclosure assemblies, the applicant stated that loss of material due to general corrosion is not applicable to Davis Besse because there is no metal enclosed bus within the scope of license renewal. During a plant walk down, the staff reviewed the station black out recovery path and noted that cable buses are used to connect bus tie transformers and the 4160 V essential switchgear buses. The applicant indicated to the staff that these cable buses were not subject to an AMP because they are not located in an adverse localized environment.

The staff agreed with the applicant that these cable buses are not required to have an AMP because GALL Report (NUREG-1801, Revison 2) Section VI does not recommend aging management for cable in air indoor or outdoor environment. However, the cable buses are protected by enclosure assemblies. These assemblies are made from galvanized steel material. Galvanized steel material in air outdoor or air indoor uncontrolled environment could be subject to loss of material due to general, pitting, and crevice corrosion.

Explain how aging of cable bus enclosure assemblies (including support structures) will be managed during the period of extended operation.

RAI 3.6-2

In LRA Section 3.6.2.2.2, the applicant stated that industry experience has shown that transmission conductors do not normally swing unless subjected to a substantial wind, and they stop swinging shortly after the wind subsides. The applicant further stated that wind loading that can result in conductor sway is considered in the transmission system design. The applicant then concluded that loss of material due to mechanical wear is not an aging effect requiring management for the high voltage insulators and transmission conductors at Davis Besse.

SRP Section 3.6.2.2 2 states that loss of material due to mechanical wear caused by wind blowing on transmission conductors could occur in high-voltage insulators. The applicant did not

address plant specific operating experience with high-voltage insulator and transmission conductor loss of material due to wear.
Review plant specific operating experience to confirm that wear has not occurred in high-voltage insulators and transmission conductors installed at Davis Besse.

RAI 3.6-3

In LRA Section 3.6.2.2.3, the applicant stated that galvanized and aluminum bolted connections are exposed to the same service conditions as the plant switchyard and do not experience any aging effects, except for minor oxidation of the exterior surfaces, which does not impact their ability to perform their intended function.

Aluminum and galvanized connections are highly conductive but do not make a good contact surface since aluminum and galvanized steel exposed to air forms oxides on the inside surface which is nonconductive and could increase the resistance of connections. SRP (NUREG-1800, Rev. 2) Section 3.6.2.2.3 states that increased resistance of connection due to oxidation in transmission conductors and connections, and switchyard bus and connections could occur. The SRP recommends a plant specific program for management of increase resistance due to oxidation for transmission conductor and switchyard bus connections.

Explain why increase resistance of connections (galvanized and aluminum bolted connections) is not an aging effect requiring management and why an AMP is not needed.

RAI 3.6-4

In LRA Table 3.6-1, Item 3.6.1-10 metal enclosed bus – enclosure assemblies, the applicant stated that hardening and loss of strength due to elastomer degradation is not applicable to Davis Besse because there is no metal enclosed bus within the scope of license renewal. During a plant walk down, the staff reviewed the station black out recovery path and noted that cable buses are used to connect bus tie transformers and the 4160 V essential switchgear buses. The applicant indicated to the staff that these cable buses were not subject to an AMP because they are not located in an adverse localized environment. The staff agreed with the applicant that these cable buses are not required to have an AMP because GALL Report (NUREG-1801, Rev. 2) Section VI does not recommend aging management for cable in air indoor or outdoor environment. However, the cable buses are protected by enclosure assemblies.

It is unclear to the staff whether or not the enclosure assemblies contain elastomers and if so, how they are being managed for hardening and loss of strength.

The staff requests the following information:

1. Explain whether or not the cable bus enclosure assemblies have elastomer components.

2. If the enclosure assemblies have elastomer components explain how aging of the components will be properly managed during the period of extended operation. An

appropriate elastomer AMP should include manual manipulation or an explanation of why manual manipulation of elastomers is unnecessary.

RAI 4.1-1

LRA Table 4.1-1 states that the CLB does not include any fatigue analysis for Class 1 valves, which is further discussed in LRA Section 4.3.2.3.2. LRA Section 4.3.2.3.2 states that a review of quality assurance records located the stress reports of record for each of the twelve Class 1 valves with four inch or greater diameter, but no associated fatigue analyses were identified. LRA Section 4.3.2.3.2 also states that "valve bodies were considered robust compared to the piping system in which they were located and fatigue of the attached piping was understood to bound the fatigue of the valve bodies."
USAR Table 5.2-1 identifies that the following Codes are applicable to the design of its Class A or Class 1 valves in the reactor coolant system (RCS):

- Pressurizer safety valves and pressurizer relief valve – 1968 Draft ASME Pump and Valve Code
- Pressurizer Pilot-Operated Relief Pressure Valves – 1974 ASME Section III inclusive of the Summer 1976 Addenda
- Pressurizer Spray Line Isolation Valve – 1986 ASME Section III
- Loop Isolation Valves both 2 ½ inches and larger and 2 inches in diameter and smaller – 1971 ASME Section III
- Other Class 1 or Class Valves both 2 ½ inches and larger and 2 inches in diameter and smaller – 1971 ASME Section III or later NRC endorsed editions of this code

USAR Table 5.1-1b identifies the valves that are included in the reactor coolant pressure boundary (RCPB).

The staff noted that the terminology for valves in USAR Table 5.1-1b does not correlate to the terminology of valves in USAR Table 5.2-1, therefore, it is difficult to confirm the statements in LRA Section 4.3.2.3 without clarifications of the specific valves, including the design code, in the RCS and RCPB.

The staff has the following issues associated with the Class 1 and Class A valves listed in USAR Table 5.2-1 and in USAR Table 5.1-1b.

Issue 1 – USAR Table 5.1-1b identifies several valves that are in the RCPB. Specifically for the seal injection flow isolation valve, pump seal return isolation valve, letdown cooler inlet valve, HP injection valve, seal return isolation valve, makeup isolation valve, letdown cooler isolation valve, pressure spray control valve, low pressure injection valve and two DH removal outlet valves, the staff is unable to correlate the specific category these valves are classified under. These categories include the following, which are identified in USAR Table 5.2-1: "2½ inch and larger – Loop Isolation Valve," "2 inch and smaller – Loop Isolation Valve," "2½ inch and larger – Other Valves," or "2 inch and smaller – Other Valves." In addition, the staff is unable to determine whether the "pressurizer relief isolation valve" or "pressurizer pilot-operated relief valve (PORV)" in USAR Table 5.1-1b correlates to the "pressurizer pilot-operated relief isolation valve" that is listed in USAR Table 5.2-1.

Without a clear correlation between USAR Table 5.1-1b and USAR Table 5.2-1 the staff is unable to verify the specific edition of ASME Section III used for the design of these valves and determine is a fatigue analysis was required by the design code.

Request 1 –

Part A:

1) Identify the edition of ASME Section III used for the design, procurement, and installation of the following valves in USAR Table 5.1-1b: (1) the seal injection flow isolation valve; (2) the pump seal return isolation valve; (3) the letdown cooler inlet valve; (4) the HP injection valve; (5) the seal return isolation valve; (6) the makeup isolation valve; (7) the letdown cooler isolation valve; (8) the pressure spray control valve; (9) pressurizer LP injection valve; and (10) each of the DH removal outlet valves.

2) For each of these valves, justify that an I_t fatigue analysis was not required in accordance with NB-3545.3 and NB-3550 of the applicable ASME Code Section III edition and the provisions for performing I_t fatigue analysis in paragraph NB-3553.

3) If an I_t fatigue analysis was performed as part of the design basis for the specific valve, justify the conclusion that the I_t fatigue analysis does not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

Part B:

1) Confirm the description for the "pressurizer relief isolation valve" in USAR Table 5.1-1b correlates to the "relief valve" in USAR Table 5.2-1.

2) Confirm the description for the "pressurizer pilot-operated relief valve (PORV)" in USAR Table 5.1-1b correlates to the "pressurizer pilot-operated relief isolation valve" in USAR Table 5.2-1.

3) If not, identify the design code that is applicable for the "pressurizer relief isolation valve" and "pressurizer pilot-operated relief valve" in USAR Table 5.1-1b.

Issue 2 (Pressurizer Safety Valve and Relief Valve) – USAR Table 5.2-1 indicates that the pressurizer safety valve and relief valve were designed to the 1968 Draft ASME Pump and Valve Code. The staff noted that Sections 452 and 454 of this Code include applicable time-dependent cyclic or fatigue assessment criteria for pumps and valves.

Specifically, Section 454 of the Code includes an I_t parameter metal fatigue analysis (cycling loading analysis). The staff verified that Section 142 of the 1968 Draft ASME Pump and Valve Code identifies that the requirements in Section 452 and 454 needs to be performed only if the inlet nozzle size for the Class 1 pump or valve was greater than 4 inches diameter nominal pipe size. Section 410 of this code states that Chapter 4 procedures and analyses (including those in Sections 452 and 454) need to be performed for small bore pumps or valves (i.e. for those pump or valves with inlet nozzles less than or equal to 4 inches in nominal pipe size) if specified by the owner's design specification. The staff noted that it is possible that small bore pumps or valves could be subject to a time-dependent cyclic or fatigue assessment.

Request 2:

- Justify why an I_t fatigue analysis was not required for the pressurizer safety and relief valves under the provisions of the 1968 Draft ASME Pump and Valve Code as part of the design basis.
- If an I_t analysis was performed as part of the design basis for these valves, justify why these analyses do not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

Issue 3 (Pressurizer Pilot-Operated Relief Isolation Valve) – USAR Table 5.2-1 indicates that the pressurizer pilot-operated relief isolation valve (PPORIV) was designed to the 1974 edition of ASME Section III, inclusive of the 1976 Summer Addenda. The staff noted that Paragraph NB-3545.3 of this code edition required that the pressure retaining portions of these valves be analyzed for fatigue in accordance with the design rules in NB-3550. This includes the requirements for performing a time-dependent (cycle-dependent) I_t fatigue analysis described in NB-3553. It is not clear to the staff if an I_t fatigue analysis for the PPORIV was performed in accordance with the requirements of ASME Section III, paragraph NB-3553.

Request 3:

- Justify why an I_t fatigue analysis was not required for the PPORIV in accordance with paragraphs NB-3545.3 and NB-3550 of the 1974 Edition of the ASME Code Section III and the provisions for performing I_t fatigue analyses in paragraph NB-3553.
- If an I_t analysis was performed as part of the design basis for the PPORIV, justify the conclusion that the I_t fatigue analysis for the PPORIV does not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

Issue 4 (Pressurizer Spray Line Isolation Valve) – USAR Table 5.2-1 indicates that the pressurizer spray line isolation valve (PSLIV) was designed to the 1986 edition of ASME Section III, with no applicable Addenda. The staff noted that Paragraph NB-3545.3 of the 1986 code edition required that the pressure retaining portion of this valve be analyzed for fatigue in accordance with the design rules in NB-3550. This includes the requirements for performing a time-dependent (cycle-dependent) I_t fatigue analysis in NB-3553. It is not clear to the staff if an I_t fatigue analysis for the PSLIV was performed in accordance with the requirements of ASME Section III, paragraph NB-3553

Request 4:

- Justify why an I_t fatigue analysis was not required for the PSLIV in accordance with paragraphs NB-3545.3 and NB-3550 of the 1986 Edition of the ASME Code Section III, and the provisions for performing I_t fatigue analyses in paragraph NB-3553.

- If an I_t analysis was performed as part of the design basis for the PSLIV, justify the conclusion that the I_t fatigue analysis for the PSLIV does not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

RAI 4.1-2

LRA Section 4.3.2.2.4 discusses the fatigue TLAA for the reactor coolant pump (RCP) casings and states that they were analyzed for fatigue by the OEM to meet the requirements of the ASME Code Section III, 1968 Edition through Winter-1968 Addenda. LRA Table 3.1.1 item 3.1.1-55 states that these pump casings will be managed by the applicant's Inservice Inspection Program.

The applicant's licensing basis includes a flaw tolerance analysis for the RCP casings that was used to support ASME Code Case N-481's alternate augmented visual inspection bases for the RCP casings. The staff noted that this flaw tolerance analysis is documented in Structural Integrity Associates (SIA) Topical Report No. SIR-99-040, Revision 1, "ASME Code Case N-481 of Davis Besse Reactor Coolant Pumps." (ADAMS Accession No. ML011200090, dated April 23, 2001).

The staff noted that the evaluation in Report No. SIR-99-040 includes a cycle-dependent fatigue flaw growth analysis for the pump casings welds that is based on a 40-year design life; however, the applicant did not identify this analysis as a TLAA.
Justify why the fatigue flaw growth analysis for the RCP pump casing welds in SIA Topical Report No. SIR-99-040, Revision 1, does not need to be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

RAI 4.1-3

The LRA Table 4.1-1 identifies "RCS Loop 1 Cold Leg drain line weld overlay repair," as a plant-specific TLAA with its disposition discussed in the LRA Section 4.7.5.1. The Section 4.7.5.1 states that, even though there is no time dependency in the weld overlay design that is a full structural overlay assuming the as-found flaw to be 100% through-wall 360-degree, fatigue analysis for the repaired configuration was performed by conservatively estimating cycles for 60 years; as such the analysis is based on a specific number of cycles and so it is a TLAA.

The staff could not identify any other instances of similarly repaired piping and nozzle locations being considered in the LRA as plant-specific TLAAs. From the LRA, it is not clear to the staff if this item in Table 4.1-1 is the only weld overlay repair where fatigue analysis was performed.

Clarify if and why the RCS loop 1 cold-leg drain line weld overlay repair is the only one to include the cycle-based or time dependent flaw growth assumptions. If there are other instances of repairs with similar analyses justify their exclusion from TLAA identification.

RAI 4.3-1

LRA Section 4.3.2.2 states that:

> 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 discussed in Section 4.3.1 above. In accordance with Davis-Besse Technical Specification 5.5.5, the Allowable Operating Transient Cycles Program (Fatigue Monitoring Program) provides controls to track the updated safety analysis report (USAR) Section 5 cyclic and transient occurrences to ensure that components are maintained within the design limits.

The staff noted that USAR Table 5.1-8 includes the classification for transients by the plant condition (e.g., normal, upset, emergency, faulted, or test). LRA Table 4.3-1, which is in LRA Section 4.3.1, includes additional transients that are not listed in USAR Table 5.1-8 and the transient classification is also not provided.

The aforementioned statement in LRA Section 4.3.2.2 implies that LRA table 4.3-1 lists only normal and upset design transients. However, the staff noted that Transient #9, "Rapid Depressurization" in LRA Table 4.3-1 is classified as an "Emergency" transient in USAR Table 5.1-8 and it is not clear to the staff if LRA Table 4.3-1 includes all emergency transients that were used in the fatigue analyses.

The staff requests the following information:

1. Clarify whether all fatigue significant transients, that have been included in the fatigue TLAAs, have been included in the LRA Table 4.3-1. Identify the plant condition (e.g., normal, upset, emergency, faulted, or test) for each transient listed in LRA Table 4.3-1.

2. Confirm whether the CUF analyses of record included emergency and test conditions in addition to the normal and upset condition. If necessary, clarify and revise the aforementioned statement in LRA Section 4.3.2.2.

RAI 4.3-2

LRA Section 4.3.1.2, "Projected Cycles," states that the analysis of the high-pressure injection (HPI) nozzles determined that the elbowlets in HPI nozzles 1-1 and 1-2 were limited to 13 cycles for Transients 9A and 9B, respectively. The applicant stated that the current cycles are at 9 and 8 for HPI nozzles 1-1 and 1-2, respectively.

In LRA Table 4.3-1, Transients 9A to 9D, labeled "Rapid RCS Depressurization" are listed in the USAR Table 5.1-8 as Transient #8. During its audit, the staff noted discrepancies in the cycle count for Transient #8 of USAR Table 5.1-8, as described in the applicant's existing Fatigue Monitoring Program (identified as "AOTC" by the applicant) logs. In the AOTC log, dated February 1990, it stated that a total of 11 cycles were recorded for this transient, out of the design limit of 13. Furthermore, an AOTC log, dated May 2003, stated that the recorded cycle count for this transient was 9.

In addition, the staff noted, during its audit, that the cycle count from the AOTC log dated February 1990 for this transient exceeded the applicant's 75% action limit, which is based on the design cycle limit of 13 cycles. It is not clear to the staff if the applicant's procedures required corrective actions and the associated results for any corrective actions that may have been taken.

The staff noted, during its audit, that the elbowlets in HPI nozzles 1-1 and 1-2 have a design CUF of 0.981 (with the limit of 13 cycles of Transients 9A and 9B). It is not clear to the staff, if there were other transients that are a significant contributor to fatigue and the number of analyzed cycles in the design CUF calculation for these components.

The staff requests the following information:

1. Describe and justify the discrepancy between cycle counts for Transients 9A to 9D, which are listed in LRA Table 4.3-1, and the cycles counts in the AOTC logs dated February 1990 and March 2003.

2. Based on the AOTC log dated February 1990, clarify whether corrective actions were taken, based on the cycle count exceeding the applicant's 75% action limit. If corrective actions were taken, describe the actions taken and the associated results of these actions. If corrective actions were not taken, explain why no action was required.

3. Identify the design transients and associated cycle limits that were used in the fatigue analysis of the HPI nozzles and elbowlets.

RAI 4.3-3

LRA Section 4.3.2.2.2.1 states that the applicant has not replaced the upper thermal shield bolts, flow distributor bolts, or guide block bolts. In addition, LRA Section 4.3.2.2.2.1 states that 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 performed as part of the original design.
LRA Table 3.1.2-2, Row Nos. 42 and 110, for upper thermal shield bolts and flow distribution bolts, respectively, credit a TLAA to manage cumulative fatigue damage.

It is not clear to the staff what TLAA is being referenced by LRA Table 3.1.2-2 Row Nos. 42 and 110, when LRA Section 4.3.2.2.2.1 states that fatigue analyses were not performed for the reactor vessel internals.

Clarify the fatigue TLAA that is being credited to manage cumulative fatigue damage of the components identified by the AMR line items in LRA Table 3.1.2-2 Row Nos. 42 and 110.

RAI 4.3-4

LRA Section 4.3.2.2.1 "Reactor Vessel" states that the design CUFs for the limiting reactor vessel assembly locations were calculated to be less than 1.0 based on the design transients. The applicant also dispositioned these fatigue TLAAs in accordance with 10 CFR 54.21(c)(1)(iii). The staff noted that the bottom head of the reactor vessel assembly is penetrated by the instrumentation nozzles which were analyzed for fatigue due to flow-induced vibrations and discussed in LRA Section 4.3.2.2.2.3. LRA Section 4.3.4.2 discusses the nickel-based incore instrument nozzle and addresses the effect of reactor coolant environment on component fatigue life.

During its audit, the staff noted that the applicant's basis documents, for metal fatigue TLAAs, lists CUF values for the instrument nozzle weld locations that vary from 0 to 0.323. LRA Section 4.3.2.2.2.3 states that the incore instrumentation nozzles were analyzed for fatigue due to flow-induced vibrations (FIV) with the resulting CUF of 0.59 for a 40-year life and was projected to have a CUF of 0.885 for a 60-year life. LRA Section 4.3.4.2 states that the maximum design CUF for nickel-based alloy incore instrument nozzle is 0.77.

The LRA does not indicate the locations that are considered to be limiting, the specific CUF values that are associated with these locations and the design transients used to determine the CUF values. In addition, it is not clear to the staff whether the generic reference of "Instrument Nozzles" in the applicant's basis documents and the LRA refer to the same locations.

The staff requests the following information:

1. Clarify the location(s) that are being referenced by the "Instrument Nozzle" CUFs in LRA Sections 4.3.2.2.1, 4.3.2.2.2.3, 4.3.4.2, and the applicant's basis documents for the metal fatigue TLAA.

2. Clarify which of these locations for the instrument nozzle of the reactor vessel assembly support the aforementioned statement in LRA Section 4.3.2.2.1 and is considered the limiting location. In addition, provide the corresponding limiting CUF values.

RAI 4.3-5

LRA Section 4.3.2.2.2.2 discusses the fatigue of reactor vessel internals subject to the flow-induced vibrations. In addition, the fatigue TLAA discussion is based on the endurance limit approach, which establishes the allowable stress limit for infinite fatigue life. The staff noted that ASME Code Section III (Mandatory Appendix I) provides the design fatigue curves.

The applicant stated that the ASME Code fatigue curve was extended to 1E+12 cycles because the 60-year projection used in the vessel internals fatigue TLAA exceeds the Code design curves. The applicant stated that an extrapolation of the curve(s) was necessary to obtain the allowable stress limit. It is not clear to the staff which Appendix I design curve was used by the applicant and the method of extrapolation used to establish the endurance limit for the 40-year analysis and the 60-year projection.

The staff requests the following information:

1. Clarify and justify the ASME Code Section III (Mandatory Appendix I) design curves used in the extrapolation described in LRA Section 4.3.2.2.2.2 for all the vessel internal materials subject to the flow-induced vibration.
2. Describe and justify the method of extrapolation for the design fatigue curves used in establishing the endurance limits. Provide the allowable stresses and the calculated peak stress intensities for fatigue of the components/locations discussed in the LRA Section 4.3.2.2.2.2.

RAI 4.3-6

LRA Section 4.3.2.2.4 states that the reactor coolant pumps (RCP) were analyzed for fatigue by the original equipment manufacturer. The applicant stated that the design CUF for the limiting coolant pump locations were calculated based on the design transients and are all less than 1.0. The LRA also states that the fatigue TLAA for the reactor coolant pumps will be managed for the period of extended operation by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii).

During its audit, the staff reviewed the applicant's basis documents for the metal fatigue TLAAs and noted that the cooling hole ligament location of the pump cover has a CUF value of 0.56. The staff also noted that the applicant's basis documents stated the CUF was calculated with an exception to the ASME Code rules. It is not clear to the staff what the exception was, and whether the exception affects the applicant's disposition for this TLAA. The staff noted that LRA Section 4.3.2.2.4 did not discuss the particular location.

Clarify the exception used for the fatigue analysis of cooling hole ligament of the RCP cover and justify that the exception does not affect the TLAA disposition of the reactor coolant pump casing fatigue evaluation.

RAI 4.3-7

LRA Section 4.3.2.6.1 states that the steam generators were analyzed for fatigue by the original equipment manufacturer (OEM) and that the CUFs for limiting locations were calculated to be less than 1.0 based on the design transients.

LRA Section 4.3 states that the new design cycle limit for the remotely welded plugs was reduced to 33 cycles (Transient 32 in LRA Table 4.3-1). During its audit, the staff noted in the applicant's basis documents for the metal fatigue TLAA, that manually welded plugs may also be limited to 33 cycles although no specific analysis was performed at the time. The staff also noted that there were other once through steam generator (OTSG) tube plug types that did not need to be qualified to the OEM equipment specification requirements. Furthermore, the staff noted that by letter dated November 3, 2003, the applicant responded to the staff's request for additional information regarding the 2002 steam generator tube inspection (ADAMS Accession No. ML033100370) and stated that there are 36 construction-era welded plugs and two of them were repaired in 2003 with remote welded plugs.

It is not clear to the staff if other types of weld plugs, such as the 36 construction-era welded plugs and the two repaired welded plugs that were not discussed in the LRA Section 4.3.2.6.1, have applicable fatigue design analysis. It is also not clear to the staff whether these other types of plugs are bounded by the remotely welded plugs which have a limit of 33 cycles for Transient 32.

Clarify whether there are other types of plugs, other than remote welded plugs, for the steam generator. If so, clarify whether these other types of plugs have applicable fatigue design analysis and provide the applicable design transients and associated limits for these plugs.

RAI 4.3-8

LRA Section 4.3.2.2.6.3 states that "The analysis of the auxiliary feedwater thermal sleeve stresses provided a basis for demonstrating that the auxiliary feedwater thermal sleeve is capable of withstanding 300 cycles of auxiliary feedwater injection transients." The applicant also stated that auxiliary feedwater (AFW) initiations (Transients 30A and 30B in LRA Table 4.3-1) are currently at 196.5 and 224.5 cycles, respectively. The staff noted that Transients 30A and 30B are projected to a maximum of 387 and 442 cycles, respectively, through the period of extended operation. These 60-year projections are less than the 875 design cycles for the riser flange attachment but exceed the 300 design cycles for the auxiliary feedwater thermal sleeve.

The staff noted that Transients 30A and 30B in LRA Table 4.3-1 are identified as "Auxiliary Feedwater <u>Bolted Nozzle</u>" (1-1 and 1-2). It is not clear to the staff whether these auxiliary feedwater injection transients refer to those transients identified in LRA Table 4.3-1.

During its audit, the staff noted that the applicant's basis documents for the metal fatigue TLAA indicated that the 3-inch auxiliary feedwater nozzles are limited to 1447 cycles of AFW initiation based on the CUF of 1.0 for the studs. It is not clear to the staff whether the design cycle limit of 1447 cycles for "AFW initiation" is tracked in the applicant's Fatigue Monitoring Program.

The staff requests the following information:

1. Clarify how the "auxiliary feedwater injection transient" for the modified AFW thermal sleeve design is related to the "Auxiliary Feedwater <u>Bolted Nozzle</u> 1-1," Transient 30A in LRA Table 4.3-1, and "Auxiliary Feedwater <u>Bolted Nozzle</u> 1-2," Transient 30B in LRA Table 4.3-1.

2. Clarify the cycle limit of 1447 for the "AFW initiations" transient discussed in the basis document for the metal fatigue TLAA and whether this "AFW initiation" transient is monitored by the Fatigue Monitoring Program during the period of extended operation. If not, justify why the "AFW initiations" transient does not need to be monitored by the Fatigue Monitoring Program during the period of extended operation.

RAI 4.3-9

LRA Section 4.3.1.2 indicates that the number of cycles accrued as of February 2008 were compiled and linearly extrapolated to the 60 years of operation to determine whether the incurred cycles would remain below the number of design cycles.

The applicant did not justify the use of a linear extrapolation to determine the number of cycles for 60 years and whether it is conservative, based on its plant-specific operating history.

Explain the methodology used for the linear extrapolation of design transients and justify that the use of a linear extrapolation to determine the number of cycles for 60 years is valid and conservative, based on the plant-specific operating history.

RAI 4.3-10

LRA Table 4.3-1 states that Transients #19, #20A, #20B, #20C, #23A, #23B, #23C, and #23D are not fatigue significant events. LRA Table 4.3-1 also states that Transients #25A and #25B are not fatigue events. Therefore, the applicant concluded that the monitoring of these transients is not needed

The applicant did not provide a discussion to explain and justify why these transients are not fatigue significant events or fatigue events.

Justify why these transients are not considered fatigue significant events or fatigue events. In addition, justify why these transients do not need to be monitored by the Fatigue Monitoring Program during the period of extended operation.

RAI 4.3-11

LRA Table 4.3-1 indicates that Transient 22A "Test-High Pressure Injection System" corresponds to Transient 12 in USAR Table 5.1-8. The applicant indicated that Transient 3 "Power change 8-100%" and Transient 4 "Power change 100-8%" correspond to Transient #3 in USAR Table 5.1-8. The applicant stated that these transients are not monitored and provided technical justifications in LRA Table 4.3-1.

The staff noted that cycle counting of the applicant's design basis transients in USAR Table 5.1-8 is required by its Technical Specification (TS) 5.5.5, unless the USAR specifically explains why the design basis transient is not monitored. The staff noted that the Revision 26 of USAR Table 5.1-8 indicates that these transients are applicable to TS 5.5.5 and the USAR does not identify the transients listed above as not requiring cycle counting.

The staff requests the following information:

1. Confirm that the "Test-High Pressure Injection System", "Power change 8-100%", and "Power change 100-8%" transients are the only transients, listed both in LRA Table 4.3-1 and USAR Table 5.1-8 that require counting per TS 5.5.5, but are not counted by the Fatigue Monitoring Program. If not, identify any additional transients that require

counting per TS 5.5.5, but are not counted by the Fatigue Monitoring Program.

2. Clarify whether USAR Table 5.1-8 currently does not require the "Test-High Pressure Injection System", "Power change 8-100%", and "Power change 100-8%" transients from the cycle monitoring requirements of TS 5.5.5.

3. Explain and justify why the monitoring of transients can be omitted without justification in USAR Section 5.2, USAR Table 5.1-8 and the applicant's cycle counting procedure.

RAI 4.3-12

The LRA does not provide the CUF values for ASME Code Section III Class 1 components described in LRA Section 4.3.2.
Without these values, the staff is not able to ascertain whether the CUF value for these locations exceeded the allowable limit or evaluate the applicant's dispositions of these TLAAs in accordance with 10 CFR 54.21(c).

Provide the design-basis 40-year CUF values for all components and/or critical locations that are applicable to the dispositions discussed in LRA Sections 4.3.2.

RAI 4.3-13

LRA Section 4.3.2.3.3 states that the CUF analyses for Class 1 High Energy Line Break (HELB) locations TLAA is dispositioned in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also stated that the effect of fatigue on the HELB location selection will be managed by the Fatigue Monitoring Program during the period of extended operation.

The staff noted that a CUF value less than 0.1 is one of the HELB location selection criteria discussed in the Standard Review Plan (NUREG-0800) Sections 3.6.1 and 3.6.2, including Branch Technical Position MEB 3-1. The staff also noted that a CUF value less than 1.0 is one of the cumulative fatigue damage design criteria in ASME Code Section III.

The staff noted that it may be possible that the design cycle limit applicable to HELB piping locations can be less than the "Design Cycles" identified in LRA Table 4.3-1. In addition, the "acceptance criteria" program element in the Fatigue Monitoring Program did not address how the acceptance criteria will be different for HELB and cumulative fatigue damage. The staff noted that the Fatigue Monitoring Program indicates that when the accumulated cycles approach the design cycles, corrective actions will be taken to ensure the analyzed number of cycles is not exceeded. However, the Fatigue Monitoring Program does not discuss the situation when the accumulated cycles approach the limit in the HELB analyses.

The staff requests the following information:

1. Identify the ASME Code Class 1 piping locations discussed in USAR Section 3.6.2 that are within the scope of LRA Section 4.3.2.3.3. Provide the design-basis transients and associated cycle limits that are applicable to each HELB piping location that are within

the scope of LRA Section 4.3.2.3.3.

2. Justify that the Fatigue Monitoring Program can adequately ensure the CUF for HELB locations remain below 0.1 by using systematic counting of plant transient cycles associated with HELB analysis. Provide any appropriate revisions to the program elements of the Fatigue Monitoring Program, as needed, to incorporate activities for ensuring that the CUF for HELB locations remain below 0.1.

RAI 4.3-14

In LRA Section 4.3.4, the applicant discussed the methodology to determine the locations that require environmentally assisted fatigue (EAF) analyses consistent with NUREG/CR-6260 "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The staff recognized that, in LRA Table 4.3-2, there are fifteen plant-specific locations listed, based on the six generic components identified in NUREG/CR-6260.

The GALL Report AMP X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary" states that the impact of the reactor coolant environment on a sample of critical components should include the locations identified in NUREG/CR-6260 as a minimum, and that additional locations may be needed. It was not clear to the staff whether the applicant verified that the plant-specific locations listed in the LRA Table 4.3-2 were bounding for the generic NUREG/CR-6260 components. Furthermore, the staff noted that the applicant's plant-specific configuration may contain locations that should be analyzed for the effects of the reactor coolant environment other than those identified in NUREG/CR-6260.

The staff requests the following information:

1. Confirm and justify that the plant-specific locations listed in LRA Table 4.3-2 are bounding for the generic NUREG/CR-6260 components.

2. Confirm and justify that the LRA Table 4.3-2 locations selected for environmentally assisted fatigue analyses consists of the most limiting locations for the plant (beyond the generic locations identified in the NUREG/CR-6260 guidance). If these locations are not bounding, clarify the locations that require an environmentally assisted fatigue analysis and the actions that will be taken for these additional locations.

RAI 4.3-15

LRA Section 4.3.1.2 states that "Transients 9C, 9D, and 32 are the only transients affecting Class 1 components where the 60-year projected cycles exceed the design cycles".

The applicant stated that HPI nozzles 2-1 and 2-2 are limited to 40 cycles for Transients 9C and 9D, respectively, and it will manage cumulative fatigue damage of these nozzles for the period of extended operation. However, it is not clear to the staff if there are other components that have Transient 9C or 9D in the design-basis fatigue calculation and whether these components will be affected if the 60-year projected cycles are exceeded.

Clarify whether there are other components that include Transients 9C or 9D in their design-basis fatigue calculation. If there are other components that use Transient 9C or 9D in their design-basis fatigue calculations, identify the number of design cycles in those fatigue calculations. Discuss and justify the fatigue TLAA disposition of these components.

RAI 4.3-16

LRA Section 4.3.4.2 and LRA Table 4.3-2 states that the in-air design CUFs were adjusted by reducing conservatism in the original design calculations and/or by refining the material specific F_{en} factor. LRA Table 4.3-2 provided a summary of the adjusted CUFs and environmentally-adjusted U_{en} factors.

Specific to the reactor vessel inlet and outlet nozzles and the pressurizer surge nozzle safe-end, the applicant stated that incremental fatigue contributions were identified and reduced based on the 60-year projected cycles. Specific to the high pressure injection/makeup nozzle and stainless steel safe-end, the applicant stated that although conservatism in the design analysis was removed and it still maintained the full-set of 40-year NSSS design transients.

It is not clear to the staff which incremental contributions were reduced based on the 60-year projected cycles, which transients were used and the number of cycles that were used in the analysis. Furthermore, it is not clear to the staff which variables in the original design calculations were adjusted, what elements of conservatism were reduced and the basis for these adjustments and reductions.

The staff requests the following information:

1. For each location in which the incremental fatigue contributions were reduced based on the 60-year projected cycles, provide the following:

    a. Identification of the transients used in the original design CUF calculation.

    b. The analyzed number of cycles used for the transients identified above in the CUF calculation.

    c. Clarification on how the incremental fatigue contribution was adjusted.

2. Clarify if there are other variables and elements of the original design calculations that were used to reduce the conservatism in the original CUFs of record. Describe and justify the reduction of conservatism for each variable and element in the original CUFs of record.

RAI 4.3-17

LRA Section 4.3.4.2 states that the surge line piping and high pressure injection/makeup (HPI/MU) nozzle and safe end were evaluated using an integrated F_{en} approach consistent with EPRI Technical Report MRP-47, "Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application," Revision 1, Section 4.2.

The staff noted that consistent with MRP-47, Section 4.2, the CUF and U_{en} are computed for each load pair and an effective F_{en} is calculated by dividing the U_{en} by the CUF. LRA Section 4.3.4 states that the maximum U_{en} is calculated with a global F_{en} and the adjusted CUF is then obtained by dividing the U_{en} by the global F_{en}.

The staff noted that EPRI Technical Report MRP-47 has not been reviewed and approved by the NRC. Furthermore, the applicant stated that in footnote 2 of LRA Table 4.3-2 the global F_{en} is calculated using the method from Section 4.2 of MRP-47. However, the term "global F_{en}" is not discussed in MRP-47. The staff further noted that the process of calculating global F_{en} is not discussed in the LRA.

Therefore, it is not clear to staff how the applicant determined the environmentally adjusted CUF for the surge line piping and HPI/MU nozzle and safe end.

The staff requests the following information:

1. Justify that use of the integrated F_{en} approach in the EPRI MRP-47 is applicable and adequately conservative to calculate U_{en} for the period of extended operation.

2. Clarify the term "global F_{en}" and how it is calculated for each component. Provide its relationship with U_{en} calculation methodology discussed in MRP-47.

RAI 4.3-18

In LRA Appendix A, Table A-1, Commitment No. 23, the applicant committed to evaluate the environmental effects on the replacement high pressure injection (HPI) nozzle safe ends and associated welds in accordance with NUREG/CR-6260 and the guidance of EPRI Technical Report MRP-47, "Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application," Revision 1, Section 4.2

EPRI Technical Report MRP-47 has not been reviewed and approved by the NRC. In addition, the applicant does not specify the specific portions of MRP-47 that will be used as part of this evaluation of environmental effects on the replacement HPI nozzle safe ends and associated welds. The staff noted that the applicant's Fatigue Monitoring Program with enhancements, in which the applicant stated is consistent with GALL AMP X.M1, addresses the effects of the reactor coolant environment on component fatigue life.

Justify that the use of EPRI Technical Report MRP-47 will properly evaluate the environmental effects on the replacement HPI nozzle safe ends and associated welds, in lieu of performing the evaluation and managing cumulative fatigue damage as part of the Fatigue Monitoring Program, which is consistent with the recommendations of the GALL AMP X.M1.

RAI 4.3-19

LRA Section 4.3.4.2, specifically the discussion of the environmental fatigue usage evaluation for the stainless steel surge line piping, states that the 60-year transient projections were used for the evaluation with the exception of the 60-year projection of heatup/cooldowns (HU/CDs), where a best estimate number of 114 total cycles were used.

The staff noted that LRA Table 4.3-1 states that the 60-year projection cycles for HU and CDs are each 128 cycles, which is based on the linear extrapolation method described in the LRA Section 4.3.1.2.

In LRA Appendix A, Table A-1, Commitment No. 9, the applicant committed to monitor any transient where the 60-year projected cycles were used in an environmentally-assisted fatigue evaluation and establish an administrative limit that is equal to or less than the 60-year projected cycles. However, in this particular analysis for the stainless steel surge line piping, the staff noted that the analyzed number of cycle for HU/CDs is less than the 60-year projected cycle.

The staff requests the following information:

1. Provide the basis of using 114 total HU/CDs in the environmental fatigue usage evaluation for the stainless steel surge line piping. Justify that the Fatigue Monitoring Program and Commitment No. 9 ensure that corrective actions are taken prior to the HU/CDs transients exceeding the analyzed number of cycles of 114 for each transient.

2. Clarify whether there are any additional locations in which the analyzed transient cycles are less than the 60-year projected cycles listed in LRA Table 4.3-1. If so, identify these locations and the associated analyzed cycles and the 60-year projected cycles for the applicable transients. In addition, justify that the Fatigue Monitoring Program ensures that corrective actions are taken prior to the applicable transients exceeding the analyzed number of cycles.

RAI 4.3-20

LRA Section 4.3.2.2.6.4 states the CUF for the 3/8" tube stabilizers is calculated using both high cycle (flow-induced vibration) and low cycle (transients) fatigue. The applicant also stated that the cumulative usage factors are only 0.12 for the tube-to-stabilizer weld and 0.07 for the nail. In addition, the applicant stated that the flow induced vibration portion of these cumulative usage factors can be increased by 1.5 for 60 years and the cumulative usage factors will remain below 1.0.

The applicant stated that in accordance with 10 CFR 54.21(c)(1)(ii), the TLAA associated with the flow induced vibration of the steam generator tubes and tube stabilizers has been projected through the period of extended operation.

It is not clear to the staff whether the CUF values of 0.12 and 0.07 for the tube-to-stabilizer weld and the nail, respectively, include both high cycle and low cycle fatigue.

It is also not clear to the staff why only the flow induced vibration portion of these CUF values are increased by 1.5 to demonstrate that the TLAA is valid for the period of extended operation and how the low cycle (transient) portion of the CUF value is being dispositioned in accordance with 10 CFR 54.21(c).

The staff requests the following information:

1. Clarify whether the CUFs of 0.12 and 0.07 are calculated considering both high cycle and low cycle fatigue.

2. Justify why the low cycle (transients) fatigue portion of the CUF values for the tube-to-stabilizer weld and nail do not need to be increased by 1.5 to determine if they will remain below 1.0. In addition, provide the disposition in accordance with 10 CFR 54.21(c)(1) for the low cycle (transient) portion of the fatigue TLAA for the tube-to-stabilizer weld and nail.

RAI 4.3-21

LRA Section 4.3.4.2 states that an environmentally assisted fatigue correction factor, F_{en}, was determined using material specific guidance contained in NUREG/CR-6583 "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels" and in NUREG/CR-6909, "Effect of LWR Coolant Environments on the Fatigue Life of Reactor Materials."

LRA Section 4.3.4.2 states that the following bounding F_{en} values calculated are: 1.74 for carbon steel, 2.45 for low-alloy steel and 4.16 for the nickel-based alloy incore instrument nozzles.

The staff noted that based on the guidance in NUREG/CR-6583 and NUREG/CR-6909, the F_{en} factor can vary based on sulfur content, temperature, dissolved oxygen, and strain rate. The staff noted that for nickel-based alloy components, per the guidance in NUREG/CR-6909, the F_{en} factor can be as high as 4.52. In addition for carbon and low-alloy steel components, per the guidance in NUREG/CR-6583, the F_{en} factor can vary significantly depending on the plant's history of dissolved oxygen content.

It is not clear to the staff, how the applicant determined the bounding F_{en} factors for the carbon and low-alloy steel and nickel-based alloy components that are described in LRA Section 4.3.4.2 and LRA Table 4.3-2.

The staff requests the following information:

1. Clarify how the bounding F_{en} factors for the carbon and low-alloy steel and nickel-based alloy components were determined.

2. Justify any assumptions, on the parameters such as sulfur content, temperature, dissolved oxygen, and strain rate, which were used in determining the F_{en} factors for these components. As part of the justification, specifically for carbon and low-alloy steel, confirm that dissolved oxygen remained less than 0.05ppm since initial plant operation. If it has not, justify that the F_{en} factors are bounding.

3. Justify that the dissolved oxygen content will remain less than 0.05ppm during the period of extended operation, such that the F_{en} factors are bounding for the conditions at the plant.

RAI 4.3-22

LRA Section A.2.3, Metal Fatigue, is divided into the following subsections:

- Section A.2.3.1, Class 1 Code Fatigue Requirements
- Section A.2.3.2, Class 1 Fatigue Analyses
- Section A.2.3.3, Non-Class 1 Fatigue Analyses
- Section A.2.3.4, Generic Industry Issues on Fatigue

10 CFR 54.21(d) requires that UFSAR supplement contain an appropriate summary description of all TLAA evaluations in the LRA.

The staff noted that LRA Section A.2.3.1 discusses the fatigue requirements for the reactor vessel and its components, Class 1 piping, and the once-through steam generator (OTSG) components. However, LRA Section A.2.3.2 does not include a summary description for all of the Class 1 components that received fatigue analysis in LRA Section 4.3.2 and its subsections. Specifically, the staff noted LRA Section A.2.3 does not include a summary description subsection for the following Class 1 components:

- Reactor vessel (RV) assembly shell components (LRA Section 4.3.2.2.1 has the corresponding analysis basis RV assembly components)
- Class 1 piping designed to ANSI B31.7 requirements (LRA Section 4.3.2.3.1 has the corresponding analysis basis)
- OTSG primary and secondary shell components (LRA Section 4.3.2.2.6.1 has the corresponding analysis basis)

Justify why LRA Section A.2.3 does not include a summary description for the RV shell assembly and its components, the Class 1 piping designed to ANSI B31.7 requirements, and the OTSG primary and secondary shells and their components.

May 2, 2011

Barry S. Allen
Vice President, Davis-Besse Nuclear
Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 3 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company, submitted an application pursuant to Title 10 *Code of the Federal Regulation* Part 54 for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,
/RA/

Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

cc w/encl: Listserv

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NAME:	YEdmonds	BHarris	BPham
DATE:	5/2/11	5/2/11	5/2/11

OFFICIAL RECORD COPY

Letter to B. Allen from B. Harris Dated May 2, 2011

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 3 (TAC NO. ME4640)

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V. Mitlyng, RII
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 5, 2011

Mr. Barry S. Allen
Vice President, Davis-Besse Nuclear Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 1 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company (FENOC), submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54) for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station (DBNPS). The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,

Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

cc w/encl: Listserv

DAVIS-BESSE NUCLEAR POWER STATION
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

RAI B.2.1–1

License renewal application (LRA) Section B.2.1 states that this is an existing program that is consistent with the Generic Aging Lessons Learned (GALL) Report aging management program (AMP) XI.S4. Element 5, "detection of aging effects," in GALL AMP XI.S4 recommends for the implementation of periodic in-service examinations for the containment structures by applying the requirements of subsections in ASME Section XI. The associated Subsection IWE-3510.1 of ASME Section XI (1995) Code states, "The general Visual Examination shall be performed by, or under the direction of, a Registered Professional Engineer or other individual, knowledgeable in the requirements for design, in-service inspections, and testing of Class MC and metallic liners of Class CC components."

In Subsection 2.1.2 of Davis-Besse Nuclear Power Station (DBNPS) Surveillance Test Procedure DB-PF-03009, Revision 06, "Containment Vessel and Shielding Building Visual Inspection," states that "Personnel who performed the examination of the exterior surface of the Containment Vessel and the shielding Building need not be qualified in accordance with NOP-CC-5708". It is not clear to the staff what/which procedure(s) is/are used to qualify personnel who perform visual examinations of the Containment Vessel and Shielding Building.

Provide qualifications of the personnel performing the visual examinations of the exterior surface of steel containment, and both sides of the shield building to be consistent with the recommendation in element 5, "detection of aging effects," of GALL AMP XI.S4.

RAI B.2.5-1

Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) Section A.1.2.3.1 states that the scope of the program should include the specific structures and components of the program that manages the aging. In addition, SRP-LR Section A.1.2.3.4 states that detection of aging effects should occur before there is a loss of the structure and component intended functions. The parameters to be monitored or inspected should be appropriate to ensure that the structure and component intended functions will be adequately maintained for license renewal under all current licensing basis design conditions. This includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new or one-time inspections to ensure timely detection of aging effects.

LRA AMP B.2.5 does not provide program specific information (e.g., monitoring technique, frequency of inspection, acceptance criteria) discussed and addressed in recent adverse industry operating experience with neutron absorber materials and staff guidance (i.e., NRC Information Notice 2009-26: Degradation Of Neutron-Absorbing Materials in the Spent Fuel Pool, and GALL AMP XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex")

The staff requests the following information:

1. Describe the material specifications (i.e., dimensions, percentage B_4C, etc.) of the Boral material. Also, provide the age, manufacturer of the material and method of fabrication.

2. Describe the surveillance approach that will be used in the cited AMP, specifically the methods and techniques utilized (e.g., visual, weight, volumetric, surface inspection, neutron attenuation testing, frequency, sample size, data collection, timing and acceptance criteria).

3. Describe how the neutron absorption capacity of the material will be monitored. Include a description of the testing, parameters measured, calculations, and acceptance criteria.

4. Discuss whether the Boral material is vented. If not, discuss how it is assured that spent fuel pool water does not leak into the sealed aluminum weld.

RAI B.2.11-1

In element 3, "parameters monitored or inspected," of the basis document LRPD-05, Aging Management Evaluation Results related to LRA AMP B.2.11, the applicant states that the technical basis for the sample selected will be documented. In the GALL AMP XI.E6 Revision 2, it states that the applicant will document the technical basis for the sample selected.

It is not clear to the staff that these statements are consistent because the applicant has not developed the technical basis and/or the criteria for the sample selection.

Provide the technical basis for the sample selection of cable connections for one-time inspection.

RAI B.2.11-2

The staff reviewed USAR A.1.11 supplement description for the program (LRA AMP B.2.11) which states that the one-time inspection uses thermography (augmented by the optional use of contact resistance testing) to detect loose or degraded connections. The staff believes that a one-time inspection is to provide additional confirmation to support industry operating experience that shows electrical cable connections have not experienced a high degree of failures and that existing installation and maintenance practices are effective. The example description for this program is provided in NUREG-1800, Revision 2 (SRP-LR) Table 3.0-1.

The purpose of the one-time inspection is to confirm that either aging of cable connections is not occurring and/or that the existing preventive maintenance program is effective such that a periodic inspection is not required.

Provide an adequate program description consistent with the description provided in SRP-LR Revision 2 Table 3.0-1.

RAI B.2.11-3

In the program basis document LRPD-05, under the parameters monitored or inspected program element, the applicant states that the inspections will include detection of loosened bolted connection due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. It further states, in part, that the following factors will be considered for sampling: connections type (i.e., bolted splices, bolted terminations, lug terminations, bolted cable terminations). Splices (butt or bolted), crimp-type ring lugs, connectors, and terminal blocks are described as the most common types of connections in the program description of GALL AMP XI.E6 Revision 2.

The NRC staff believes that loosening of cable connections may also occur in different types of connections and may not only be limited to bolted connections.

Provide a technical justification of why only bolted connections are considered in the inspection sample criteria.

RAI B.2.11-4

During a plant walkdown, the staff noted cable bus connections in a terminal housing connecting cable bus, bus tie transformers, and in the 4160 V essential switchgear buses. The applicant indicated to the staff that these cable buses were not subject to aging and are not included in an AMP because they are not located in an adverse localized environment.

The staff agreed with the applicant that insulation material for cable buses and connections are not subject to an AMP. However, metallic material of cable bus connections may experience increased resistance of connection due to loosening of bolted connections caused by repeated thermal cycling of connected loads.

Explain how aging of cable bus connections will be managed during the period of extended operation (PEO).

RAI B.2.20-1

Periodic draining and cleaning of diesel fuel tanks is performed so that internal surfaces can be visually and volumetrically inspected allowing for detection of corrosion and other degradation inside the tanks. Regulatory Guide 1.137 "Fuel Oil Systems for Standby Diesel Generators," Revision 1, Regulatory Position C.2.f, documented in GALL Report Revision 2, recommends draining and cleaning of diesel fuel tank internal surfaces at least once every 10 years during the period of extended operation.

LRA AMP B.2.20, "Fuel Oil Chemistry Program," states that the diesel fire pump day tank (DB-T47) and the station blackout diesel generator day tank (DB-T210) are cleaned and inspected every 12 years. The applicant states that LRA AMP B.2.20 is consistent with GALL AMP XI.M30, "Fuel Oil Chemistry," with exceptions.

The LRA is not consistent with the 10-year draining and cleaning frequency for diesel fuel tanks recommended by the GALL Report. Instead, the LRA states that draining and cleaning of the DB-T47 and DB-T210 tanks are performed on a 12-year interval.

Discuss how the 12-year interval for draining and cleaning of tanks DB-T47 and DB-T210 is consistent with the GALL AMP XI.M30, "Fuel Oil Chemistry." Alternatively, provide a revision to your draining and cleaning frequency such that it is on a 10-year interval.

RAI B.2.20-2

The performance of volumetric inspections on degradation identified by visual inspections of the diesel fuel tank internal surfaces is an acceptable means to verify the presence of corrosion or other degradation inside the tanks. Volumetric inspections are to be performed if evidence of degradation is observed during visual inspections of diesel fuel tank internal surfaces, or if visual inspection is not possible, as recommended in GALL Report Revision 2.

LRA AMP B.2.20 does not explicitly state and it is not clear to the staff whether volumetric inspections of degradation identified by visual inspections of tank internal surfaces will be performed.

If degradation is identified in a diesel fuel tank by visual inspections or if visual inspection is not possible, please discuss whether volumetric inspections will be performed to verify the degradation or inspect tank internal surfaces.

RAI B.2.20-3

The Final Safety Analysis Report (FSAR) Supplement description contained in the SRP-LR provides an acceptable program description for the GALL AMP XI.M30, "Fuel Oil Chemistry," which includes the specific ASTM Standards to be used for monitoring and control of fuel oil contamination to maintain fuel oil quality. LRA A.2.20 "Fuel Oil Chemistry Program" states:

> 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 International (ASTM) standards for fuel oil.

Specifying the ASTM Standards to be used ensures that there is an adequate description of the critical elements of the Fuel Oil Chemistry Aging Management Program to provide assurance that the program will be properly executed during the period of extended operation. LRA FSAR Supplement A.2.20 does not include ASTM standards D975, D2276, D2709, D4057 and D4176 found in element 1, "scope of program," of LRA AMP B.2.20.

Justify the absence of the above mentioned ASTM standards in your FSAR Supplement provided in LRA Appendix A. Alternatively, provide a revision to your FSAR supplement to add the specific ASTM standards.

RAI B.2.21-1

GALL AMP XI.E3, "Inaccessible Medium Voltage Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements," addresses inaccessible medium voltage cables. The purpose of this program is to provide reasonable assurance that the intended functions of inaccessible medium-voltage cables (2 kV to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by moisture while energized, will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (in conduits, cable trenches, cable troughs, duct banks, underground vaults or direct buried installations) medium-voltage cables within the scope of license renewal that are subject to significant moisture simultaneously with significant voltage (energized 25% of the time).

The application of AMP XI.E3 to medium-voltage cables was based on the operating experience available at the time Revision 1 of the GALL Report was developed. However, industry operating experience subsequent to GALL Report Revision 1 indicates that the presence of water or moisture can be a contributing factor in inaccessible power cable failures at lower service voltages (400 V to 2 kV). Applicable operating experience was identified in licensee responses to Generic Letter (GL) 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," which included failures of power cable operating at service voltages of less than 2 kV where water was considered a contributing factor. The staff also noted that the significant voltage screening criterion (subject to system voltage for more than energized 25% of the time) was not applicable for all the inaccessible power cable failures noted.

Industry operating experience provided by NRC licensees in response to GL 2007-01 has shown: (a) that there is an increasing trend of cable failures with length in service, and (b) that the presence of water/moisture or submerged conditions appears to be the predominant factor contributing to cable failure. The staff has determined, based on the review of the cable failure data, that an annual inspection of manholes and a cable test frequency of at least every six years (with evaluation of inspection results to determine the need for an increased inspection frequency) is a conservative approach to ensuring the operability of power cables and, therefore, should be considered. The use of test and inspection frequencies in the determination of the need for adjustment of test and inspection frequencies should also be considered.

In addition, industry operating experience subsequent to GALL Report Revision 1 has shown that some NRC licensees may experience cable manhole water intrusion events, such as flooding or heavy rain, that subjects cables within the scope of program for GALL AMP XI.E3 to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to a 1-year periodic inspection frequency, is a conservative approach and, therefore, should be considered.

The staff requests the following information:

1. Provide a summary of your evaluation of recently identified industry operating experience and any plant-specific operating experience concerning inaccessible low voltage power cable failures within the scope of license renewal (not subject to 10 CFR 50.49 environmental qualification requirements), and how this operating experience applies to the need for additional aging management activities for such cables.

2. Explain how DBNPS will manage the effects of aging on inaccessible low voltage power cables within the scope of license renewal with consideration of recently identified industry operating experience and any plant-specific operating experience. The discussion should include assessment of your aging management program description, program elements (i.e., "scope of program," preventive actions," parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and acceptance criteria"), USAR summary description and applicable license renewal commitment to demonstrate reasonable assurance that the intended functions of inaccessible low voltage power cables subject to adverse localized environments will be maintained consistent with the current licensing basis through the PEO.

3. Provide an evaluation showing how the Non-EQ Inaccessible Medium-Voltage Cable Program test and inspection frequencies, including event driven inspections, incorporate recent industry and plant-specific operating experience for both inaccessible low and medium-voltage cable. Explain how the Inaccessible Medium-Voltage Cable Program will ensure that future industry and plant-specific operating experience will be incorporated into the program such that inspection and test frequencies may be increased based on test and inspection results.

RAI B.2.21-2

GALL AMP XI.E3 states that periodic actions are taken to prevent inaccessible cables from being exposed to significant moisture, such as identifying and inspecting in-scope accessible cable conduit ends and cable manholes for water collection, and draining the water, as needed.

Manhole MH3045, based on work orders, corrective actions, system health reports, and staff inspection reports, has continued to experience water intrusion and cable submergence. Corrective actions have included increased inspection frequencies and, more recently, the installation of a temporary sump pump to limit the exposure of in-scope inaccessible cable to significant moisture.

Provide a commitment to implement the corrective actions (such as permanent sump pump, cable replacement, increased inspection frequencies, and testing) for manhole MH3045 to prevent in-scope inaccessible cable from being exposed to significant moisture (cable wetting or submergence) so that these cables will continue to perform their intended functions during the PEO.

RAI B.2.21-3

GALL AMP XI.E3 states that for this AMP, periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes, and draining water as needed.

GALL AMP XI.E3, element 2, states in part that the inspection should include direct observation that cables are not wetted or submerged. The staff is concerned that power plant work orders developed to inspect manholes including manholes in-scope for license renewal do not specifically require documentation if in-scope inaccessible cables are found submerged. Although procedures require inspecting for water level and pumping out any water found, the maintenance work orders do not have an action to identify in-scope cables found submerged. Without this step it is not clear how cables exposed to significant moisture would be identified and how additional corrective actions would be taken. Reference work orders PM 4297, PM 4294, PM 8025, and PM 4296.

Explain how in-scope inaccessible power cables that are exposed to significant moisture will be identified and how corrective actions will be taken through referenced plant work orders.

RAI B.2.21-4

GALL AMP XI.E3 states that for this AMP, periodic actions are taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes, and draining water as needed. The staff reviewed manhole drawings provided by the applicant and noted that some of the manholes in the scope of license renewal do not have sump pumps but drain to manholes that are not in scope that do have sump pumps.

It is not clear to the staff that the sump pumps located in manholes not in scope of AMP B.2.21 but connected through common drainage systems (a common sump for the duct bank system) would be inspected/functionally tested. Because these sump pumps are used to prevent in-scope inaccessible power cables from being exposed to significant moisture, the staff is concerned that sump pumps not located in in-scope manholes may not be inspected/functionally tested under LRA AMP B.2.21.

Explain how sump pumps not included in the in-scope manholes but used to prevent in-scope inaccessible power cables from being exposed to significant moisture are inspected and functionally tested with the associated in-scope manholes under LRA AMP B.2.21.

RAI B.2.21-5

System Health Reports (including 2010-04), and other site documents reference a medium-voltage wetted cable replacement program as part of the health improvement plan. The System Health Reports identify medium-voltage underground cables located in a potentially wet environment that are scheduled for replacement. The System Health Reports state that the priority for cable replacement is based on identified corrective actions and considers the following factors: (1) risk significance, (2) length of time a cable is energized, (3) cable age, (4) insulation type, and (5) connected equipment

GALL AMP XI.E3, element 7, "corrective actions," states that when an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other accessible or inaccessible, in-scope power cables. Element 7 further states that corrective actions may include, but are not limited to, installation of permanent drainage systems, installation of sump pumps and alarms, more frequent cable testing or manhole inspections, or replacement of the affected cable.

The identification of wetted medium-voltage cable replacement with respect to inaccessible power cables in scope of license renewal (GALL AMP XI.E3) is not specifically referenced or described in the System Health Reports.

Provide a discussion of the medium-voltage wetted cable replacement program as applicable to license renewal. Discuss criteria for replacement including prioritization or deferred replacement with monitoring (testing). Provide information detailing the in-scope inaccessible power cables included in the replacement program, the number of in-scope inaccessible power cables replaced, and the planned schedule for in-scope inaccessible power cable replacement or monitoring (testing).

RAI B.2.22-1

GALL AMP XI.S1, "ASME Section XI, Subsection IWE," element 6, recommends that the areas that are found to be suspect during visual examination require an engineering evaluation or require correction by repair or replacement.

During the AMP audit at DBNPS, the staff interviewed the applicant staff and reviewed documentation about the ground water seepage in different plant structures. The staff found that there is history of ground water infiltration into the annular space between the concrete shield building and steel containment.

During the audit, the staff also reviewed documentation (CR 10-72660) that indicated the presence of standing water in the annulus sand pocket region. The standing water appears to be a recurring issue of ground water leakage and areas of corrosion were observed on the containment vessel. In addition, during the audit the staff reviewed photographs that indicate peeling of clear coat on the containment vessel annulus area, and degradation of the moisture barrier, concrete grout, and sealant in the annulus area that were installed in 2002-2003.

The staff requests the following information:

1. Plans and schedule to perform nondestructive examinations, such as ultrasonic testing (UT) of the steel containment in the sand pocket region including the area below and above the grout.

2. The condition of the drains located in the sand pocket region, and if the water exiting from these drains is monitored.

3. Plans and schedule to remove/replace/repair degraded grout, moisture barrier, and sealant.

4. Corrosion rate in the inaccessible area of the steel containment that can be reasonably inferred from UT examinations or from representative samples in similar operating conditions, materials, and environments.

5. Using the established corrosion rate, demonstrate that the steel containment will have sufficient thickness to perform its intended function through the PEO.

RAI B.2.22-2

GALL AMP XI.S1, "ASME Section XI, Subsection IWE," element 1, states that 10 CFR 50.55a(b)(2)(ix) specifies additional inspection requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

During the site audit, the NRC staff reviewed documentation that indicated borated water leakage into the East/West and Incore instrumentation tunnels from the refueling cavity. The borated water leaks from the reactor cavity floor through the construction joint at the base of 4-foot thick East/West tunnel wall (elevation 550'-6"). The borated water has degraded the concrete wall coating, and corroded the conduits, piping, and supports in the East/West tunnel and Incore instrumentation tunnel.

There are approximately 2 feet of concrete between the reactor cavity floor and steel containment. Based on the observed leakage from a 4-foot thick wall, it is likely that borated water has also leaked on the top embedded steel containment and may cause its degradation/corrosion.

Provide details of actions planned to examine the inaccessible portion of the steel containment. Specifically, provide details of any plans to remove concrete at the bottom of normal sump (approximate elevation 536) to expose and inspect steel containment for degradation. In addition, provide details and plans for a study to determine the effect of the loss of thickness in the steel containment due to exposure to borated water over the PEO. The study should also address the potential of borated water flowing on top of the steel containment and leaking through the concrete into the normal sump. The staff needs this information to verify that the effects of aging on the intended function of the steel containment plate will be adequately managed for the PEO.

RAI B.2.22-3

GALL AMP XI.S1, "ASME Section XI, Subsection IWE," element 10, recommends that steel containment corrosion concerns described in the NRC generic communications should be considered. In addition, GALL AMP XI.S1 states that ASME Section XI, Subsection IWE requires examination of coatings that are intended to prevent corrosion.

It is not clear from the review of the LRA if the applicant's ASME Section XI, IWE AMP requires examination of coatings that are intended to prevent corrosion.

Please clarify if the ASME Section XI, IWE AMP inspects and credits coating on the inside surface of the steel containment for corrosion protection.

RAI B.2.22-4

DBNPS LRA Section 4.6.2 states a search of the DBNPS current licensing basis did not identify any pressurization cycles or fatigue analyses for containment penetration assemblies.

Containment piping penetration sleeves examination is included in the scope of the GALL AMP XI.S1 ASME Section XI, Subsection IWE. In addition, DBNPS steel penetration sleeves, dissimilar metal welds, bellows, and steel components are subject to cyclic loading during plant operation. In absence of a fatigue analysis, these components are required to be monitored for cracking. It is not clear to the staff if steel penetration sleeves, dissimilar metal welds, and steel components are included in the scope of the program and monitored for cracking.

Please clarify if the ASME Section XI, IWE AMP monitors steel penetration sleeves, dissimilar metal welds, bellows, and steel components for cracking due to cyclic loading.

RAI B2.23-1

GALL AMP XI.S3, "ASME Section XI, Subsection IWF," element 5, "monitoring and trending," states that for IWF examinations of component supports, if a component's present condition is discovered to be different from its previous condition identified in prior examination, such changes in condition should be documented in accordance with ASME IWA-6230. The staff reviewed program element 5, "monitoring and trending," of the DBNPS in-service inspection (ISI) program – IWF basis documents and did not identify a reference to ASME IWA-6230 for documenting newly discovered changes in condition.

Provide information on the procedure by which changes in condition are documented in the IWF program in accordance with the provisions of ASME IWA-6230. If changes in condition are not currently being documented, explain how changes of condition from prior examination will be documented as part of the IWF AMP in accordance with ASME IWA-6230.

RAI B2.25-1

SRP-LR Section A.1.2.3.1 and Table A.1, state that the "scope of program," program element should include the specific structures and components of which the program manages the aging. In LRA B.2.25 the applicant states that the Leak Chase Program will monitor borated water leakage from the spent fuel pool, the fuel transfer pit, and the cask pit stainless steel liners due to age-related degradation. In its "scope of program," program element, the LRA states that the Leak Chase Monitoring Program is credited with detecting loss of material in the liners and further focuses the program on the integrity of the liner welds. In its "operating experience," program element, the LRA reviews the impact the leakage had on the leak chase system (channels, valve bodies, etc.) and on the contiguous concrete structures. It also states that borated water is evidenced in the Auxiliary Building but there are no concerns regarding the strength or integrity of the concrete structure. The same program element discusses monitoring of the tell-tale drains and the effort made to unclog the drains. Finally, LRA Table 3.5.2-2, titled "Aging Management Review Results - Auxiliary Building," identifies three programs to manage the aging effects of the spent fuel pool liner: the PWR Water Chemistry Program, the Davis Besse Tech Specs, and the Leak Chase Program.

It is not clear to the staff the extent of the scope of the Leak Chase Program. LRA Section B.2.25 discusses not only monitoring of borated water leakages but also monitoring and detection of aging effects for the leak chase system, its components, and the associated concrete structures.

Identify the full scope of the program. Does the AMP track only the borated water leakages or does it also expand to manage aging effects for the entire leak chase system, including its materials, components, and structures exposed to borated water? If the program includes components of the leak chase system, where in the AMR Results Tables does the applicant address the management of aging effects for the wall/floor channels, tubes, trenches, and valve casings?

RAI B2.25-2

SRP-LR Section A.1.2.3.3 and Table A.1-1, state that the "parameters monitored or inspected," program element recommends the identified parameters to be linked to the degradation of the particular structures and components intended function(s). For a condition monitoring program, the parameters monitored or inspected should detect the presence and extent of aging effects which according to the GALL Report and SRP-LR are loss of material due to pitting and crevice corrosion and cracking due to SCC of the spent fuel pool, the fuel transfer pit, and the cask pit stainless steel liners.

In LRA B.2.25 "parameters monitored or inspected," program element, the applicant states that the program monitors the amounts and rate of leakage accumulated in the leak chase system and collected from each of the zone valves. In Table 3.5.2-2 of the LRA, titled "Aging Management Review Results - Auxiliary Building," the applicant further states that weekly, it also monitors the spent fuel pool water, per DBNPS Tech Specs, Section 3.7.14, titled "Spent Fuel Pool Water Level."

The LRA "parameters monitored or inspected," program element states that it only monitors the amount of borated water leakage through the tell-tale drains linked to the zone valves. There is no discussion of the weekly surveillance of the water level in spent fuel pool and how that is correlated to the collected leakage. There is also no discussion of water evaporation during the lengthy monthly accumulations of borated water in the leak chase system which could lead to increasingly acidic water that could accelerate the aging effects on channels, tubes, trenches, valve bodies, etc and faulty readings in boron concentrations. It is not clear to the staff what kind/type of materials make up the leak chase drainage system, how these are impacted by the acidic leakage, and how the applicant tracks the variation in the acidity of the borated water. It is also not clear to the staff what additional parameters the applicant monitors for this degradation so that the leak chase drainage system will continue to perform adequately during the PEO.

The staff requests the following information:

1. Identify the material used (e.g., carbon steel, A36) for each of the following: leak chase channels, collector tubes, zone drains, leak trenches, and for any other component (other than the liners) that the leak chase system uses for drainage of borated water.

2. How does the applicant relate the leakage of the borated water to observed degradations, if any, of the leak chase system materials and components (liners, liner weldments, channels, tubes, trenches, valve bodies, etc.) and to the level of water in the spent fuel pool?

3. In addition to the monitoring of the boron concentration in the leakage and the water level in the spent fuel pool, does the applicant monitor the concentration of any other elements (e.g., Fe) or the acidity (i.e., pH) of the collected leakage or additional parameters that could be related to aging effects of the leak chase system and its components? If other parameters are measured, discuss the acceptance criteria for each measured parameter.

RAI B2.25-3

SRP-LR Section A.1.2.3.4 and Table A.1-1, in "detection of aging effects," program element state that detection of aging effects should occur before there is a loss of structure or a component's intended function(s). The program element should address aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection used and the timing of new/one-time inspections to ensure timely detection of aging effects. Aging effects/mechanisms to detect, according to SRP-LR and the GALL Report, are loss of material and SCC. Timing for the detection of aging effects is based on plant-specific or industry-wide operating experience.

In LRA B.2.25, the applicant states in the "scope of program," program element that the program is credited for detection of loss of material in the liners, while in its "detection of aging effects," program element it states the detection is done on a monthly basis by recording the amount of accumulated borated water in the zone drain valves of the spent fuel pool, the fuel transfer pit, and the cask pit liners. Monthly collected leakages from any valve in excess of 10 milliliters are labeled, further analyzed for boron content, and the results documented in the work order system. The LRA also states that this type of monitoring supports early determination and localization of leakages. In LRA Table 3.5.2-2, titled "Aging Management Review Results - Auxiliary Building," it further states that there are three programs in place set to manage the aging effects of the spent fuel pool liner: the PWR Water Chemistry Program, the DBNPS Tech Specs, and the Leak Chase Program.

It is not clear to the staff, how the applicant correlates the monthly collected information of the borated water leakage and its analysis to the weekly Tech Specs surveillance of the spent fuel pool water level. The LRA does not state how this information collectively provides timely detection and localization of leakages in the leak chase system and its associated components and structures, including cracking due to SCC and loss of material due to pitting and crevice corrosion. It is also not clear to the staff if the applicant uses any additional detection techniques capable of identifying the continued functionality of the system during the PEO.

The staff requests the following information:

1. Elaborate on how the Tech Specs and Leak Chase Program can collectively identify detection for loss of material and SCC aging effects in the liners and leak chase system.

2. Since condition monitoring programs are based on either visual or volumetric inspections, what detection method(s) (e.g., boroscopes, fiber optics, etc.), other than monitoring the amount of the leaked borated water, does the applicant employ to ascertain the integrity and functionality of the leak chase channels (i.e., these remain unclogged and intact, devoid of rust and accumulated boric acid) during the PEO?

RAI B2.25-4

SRP LR Section A.1.2.3.5 and Table A.1-1, in "monitoring and trending," program element state that the element should provide predictability of the extent of degradation allowing timely response for corrective or mitigative actions and that aging indicators quantitative or qualitative, should be quantified, to the extent possible, to allow trending. The SRP-LR and the GALL Report, also state that monitoring should be done both for the spent fuel pool water level according to the plant Tech Specs and the level of fluid in the leak chase channels.
In LRA B.2.25, the applicant stated in the "monitoring and trending," program element that the Leak Chase Monitoring Program routinely monitors the leak chase valves. A leak rate then is calculated based on the recorded monthly leakage. When the collected leakage from any drain valve exceeds 10 milliliters, then the sample is analyzed for boron concentration. The recorded data is reviewed by the spent fuel pool system engineer. Adverse conditions are documented in the Corrective Action Program and summarized in System Health Reports.

In a letter dated July 31, 2006, to the "Industry Groundwater Protection Initiative Questionnaire," FENOC states that monitoring in its Beaver Valley Station is performed daily, while in the Perry Nuclear Power Plant it is done weekly. It is not clear to the staff how the monthly leakage monitoring activities at DBNPS could be compared and trended to the industry standards and the weekly plant-specific requirements of the spent fuel pool water level surveillance. It is also not clear to the staff how the applicant would trend a degrading or compromising liner environment and/or leak chase drainage system. Finally, the LRA does not state how the monthly activities of leakage collection, analysis, and recording could provide a timely prediction of the extent of liner degradation or forward trending of anticipated leakages from the spent fuel pool which is a Class I structure.

The staff requests the following information:

1. Justify the basis for selecting monthly checking of leakages at DBNPS.

2. Explain how monthly monitoring provides adequate information for trending leakage rates and boron concentrations to predict the integrity of the leak chase system including the liner of the Class I structure.

RAI B2.25-5

SRP LR Section A.1.2.3.6 and Table A.1-1 state that the acceptance criteria of the program and their basis, according to the referenced "acceptance criteria" program element, should be described so that the need for corrective actions is evaluated. Acceptance criteria should be specific and quantifiable to ensure that the structures and components' intended function(s) remain under all CLB design conditions during the PEO. The program should include a methodology for analyzing the results against applicable acceptance criteria.
In LRA B.2.25 the "acceptance criteria," program element states that adverse trends are documented in the Corrective Action Program. The LRA also states that adverse trends are those with continued increases of leak rates on a particular zone valve.

Although the SRP-LR guidance recommends sound quantitative or qualitative acceptance criteria for the periodic inspections, the LRA in its "acceptance criteria," program element does not indicate what specific numerical values of increasing leak rates would be considered to trigger the need for corrective actions. The acceptance criteria are neither specific nor quantifiable but rather subjective depending on the review of the collected data by the responsible system engineer. It is also not clear to the staff what constitutes "abnormal" data. Nor does the applicant state what kind of methodology it uses to analyze such results against industry applicable acceptance criteria. The acceptance criteria should provide for timely corrective action before loss of intended function(s), thus meeting the criteria set under CLB.

The staff requests the following information:

1. Is there a threshold of an unacceptable/adverse increase in leakage rates of borated water that would constitute the basis to trigger corrective actions? What would the corrective actions be?

2. Is there a drain zone that is permitted to have more leakage than others?

RAI B2.25-6

SRP-LR Revision 2, Tables 3.0-1 and 3.5-2 state that plant-specific AMPs should contain information associated with the bases for determining that aging effects, in this case loss of material and SCC in stainless steel liners, will be managed during the PEO. LRA Appendix A, titled "Updated Final Safety Analysis Report," in paragraph A.1.25, titled "Leak Chase Monitoring Program," states that the program is a periodic condition monitoring program focusing on observations and activities for early detection of leakage from the spent fuel pool, the fuel transfer pit, and the cask pit liners due to age-related degradation.

There is no description in the Updated Final Safety Analysis Report (UFSAR) of what aging effects the program manages. The program also does not state or give a brief description of its activities.

Identify the aging effects being managed and summarize the activities involved.

RAI B.2.26-1

The staff noted that water contamination in lubricating oil can cause an environment that is conducive to loss of material or reduction of heat transfer. In addition, areas of stagnant oil flow are susceptible to water accumulation and have the potential to go undetected with the current standard industry testing techniques.

GALL AMP XI.M39 "Lubricating Oil Analysis," states that water and particle concentration should not exceed limits based on equipment manufacturer's recommendations or industry standards. Additionally, it states that phase-separated water in any amount is not acceptable. The staff noted during its audit that LRA Section B.2.26 and the applicant's program basis document does not indicate that any testing is performed to detect the presence of phase-separated water, nor do they provide any corrective actions that will be taken if phase-separated water is detected.

Describe the tests that will be performed to detect for the presence of phase-separated water in lubricating oil systems within the scope of license renewal. If testing for phase-separated water will not be performed, clarify and provide technical justification for the preventative actions taken in order to prevent phase-separated water accumulation from occurring. Conversely, if preventative actions are not to be taken to prevent phase-separated water accumulation, provide technical justification for why no action is needed.

RAI B.2.27-1

GALL AMP XI.S5 element 6, "acceptance criteria," states that corrective actions should be taken if the extent of cracking or steel degradation is sufficient to invalidate the evaluation basis.

The applicant's Masonry Wall Inspection procedures do not provide guidance or acceptance criteria for what level of degradation leads to a reevaluation of the existing evaluation basis.

Describe the acceptance criteria that are used to trigger corrective actions, including reevaluating the existing evaluation basis. Provide technical justification for the adequacy of the acceptance criteria.

RAI B.2.38-1

The staff has identified potential inconsistencies between NEI 97-06, Revision 2, and the standard steam generator technical specifications which the applicant has adopted (through its adoption of TSTF-449). These inconsistencies were discussed in a public meeting on September 16, 2009, between the Nuclear Energy Institute Steam Generator Task Force and the U.S. Nuclear Regulatory Commission (refer to meeting summary dated October 6, 2009 (Agencywide Documents Access and Management Systems Accession Number ML092820119)).

The potential inconsistencies between NEI 97-06, Revision 2, and the standard steam generator technical specifications raises questions on whether all the applicant's technical specification requirements will be satisfied.

Please confirm that your steam generator AMP has addressed the potential inconsistencies between NEI 97-06 and your technical specifications.

RAI B2.39-1

A review of program basis documentation related to program element 10, "operating experience," noted that during Maintenance Rule Evaluation of Structures Inspections boric acid deposits had been observed over a large surface area of the Containment Incore Instrumentation Tunnel walls and the under-vessel area that are indicative of refueling canal leakage. This included numerous boric acid indications on the concrete and on structural members below the elevation of the refueling cavity. It was also noted that the leakage was coming through the reinforced concrete construction joints and shrinkage cracks, running down the wall to the floor, and in some places under the grating in the tunnel.

It is unclear to the staff that the effects of refueling cavity leakage on the containment internal concrete structures have been adequately addressed and that the possible aging effects will be properly managed during the PEO.

The staff requests the following information:

1. Provide background information and/or data to demonstrate that the concrete and embedded steel reinforcement potentially exposed to the prior borated water leakage has not been degraded. If experimental results will be used as part of the assessment, provide evidence that the test program is representative of the materials and conditions that exist.

2. Discuss any remedial actions or repairs that are planned to address refueling cavity leakage and when they will be implemented. In the absence of a commitment to stop the refueling cavity leakage, explain how the structures monitoring program, or other plant-specific program, will address the refueling cavity leakage to ensure that resulting aging effects, especially in any inaccessible areas, will be effectively managed during the PEO.

RAI B2.39-2

A review of program basis documentation related to program element 10, "operating experience," noted that during Maintenance Rule Evaluation of Structures inspections, water had been noted to leak from the Spent Fuel Pool and travel through the surrounding concrete. The leakage has been active periodically into the ECCS pump room #1. Indications of cracking and staining on the underside of the Spent Fuel Pool and Transfer Pit (ceiling of Room 109) were also observed during a plant walkdown.

Investigation and evaluation of the periodic spent fuel pool leak indicated that six of the twenty-one leak chase channels were blocked. The leak chase channels were un-clogged releasing a significant amount of trapped fluid in several of the blocked leak chase channels. After un-clogging, the leak collection isolation valves were cleaned. Since that time, leak detection activities have been performed monthly with intermittent small quantities of fluid having been captured from several leak chase channels. Recent results indicate that two of the leak chases drains are exhibiting continual small leakage. It is unclear to the staff that the concrete and steel reinforcement of the spent fuel pool have not been impacted by the borated water.

The staff requests the following information:

1. Provide historical data on the leakage occurrence and volume, and available results from chemical analysis performed on the leakage.

2. Provide the root cause analysis that was performed to identify the source of leakage, including information on the path of the leakage and structures that could potentially be affected by the presence of the borated water. If the analysis indicates that the current leakage is completely contained within the leak chase channels, provide a technical justification for this assumption and explain how it will continue to be validated during the period of extended operation.

3. Provide background information and data to demonstrate that concrete and embedded steel reinforcement potentially exposed to the borated water have not been degraded. If experimental results will be used as part of the assessment, provide evidence that the test program is representative of the materials and conditions that exist. If a concrete sampling program (e.g., obtaining cores in region affected) will not be implemented, please explain why this is not feasible or not necessary.

4. Discuss any remedial actions or repairs that are planned to address concrete cracking such as observed on the underside of the spent fuel pool and when they will be implemented. In the absence of a commitment to repair the concrete cracking prior to the PEO, explain how the structures monitoring program, or other plant-specific program, will address the concrete cracking to ensure that aging effects, especially in any inaccessible areas, will be effectively managed during the PEO.

RAI B2.39-3

The GALL Report notes that for plants with aggressive ground water/soil (pH < 5.5, chlorides > 500 ppm, and sulfates > 1500 ppm) and/or where the concrete structural elements have experienced degradation, a plant-specific AMP accounting for the extent of degradation experienced should be implemented to manage concrete aging during the PEO. In Revision 1 of the GALL Report, this recommendation is provided in item T-05, while in Revision 2 it is captured in the guidance for GALL AMP XI.S6, "Structures Monitoring," and XI.S7, "Inspection of Water-Control Structures."

Program element 3, "parameters monitored or inspected," of the DBNPS Structures Monitoring Program basis document notes that the chemical parameters for DBNPS groundwater are considered to be aggressive (i.e., chlorides = 2780 ppm (max) and sulfates = 1700 ppm (max)). Program element 10, "operating experience," notes that the Turbine Building has active water in-leakage and evidence of water in-leakage was observed in several locations in the floor and walls of the Turbine Building by the NRC audit team during the plant walkdown. Also, program basis documentation has identified groundwater intrusion into ECCS Pump Room and ECCS cooler, the East Condenser Pit through various joints and seams in the east wall below the condensate storage tank, efflorescence in the south and east exterior walls of Room 121 of the Auxiliary Building, and the annulus sand pocket. Indications of in-leakage of ground water were also observed at an overhead joint in the service water tunnel during a plant walkdown.

LRA Section B.2.39 states that the DBNPS Structures Monitoring Program will be enhanced to require the responsible engineer to review the raw water chemistry for unusual trends during the PEO, raw water chemistry will be collected at least once every five years with data collection staggered to account for seasonal variations, and monitoring of below-grade inaccessible concrete components will be implemented before the PEO. However, it is unclear to the staff that inaccessible concrete components have not been adversely impacted by the aggressive ground water and when an examination of an inaccessible concrete component will be conducted.

The staff requests the following information:

1. Provide background information and data to demonstrate that the concrete and steel reinforcement subjected to aggressive groundwater is not degrading. If an inspection of an effected inaccessible concrete component will be conducted prior to the PEO, provide details about the inspection, including the proposed schedule and how the inspection will demonstrate the acceptability of effected concrete throughout the plant. If a concrete sampling program (e.g., obtaining cores in an affected region) will not be implemented, explain why this is not feasible or not necessary.

2. Explain how the structures monitoring program, or other plant-specific program, will address aggressive groundwater infiltration to ensure that resulting aging effects, especially in any inaccessible areas, will be effectively managed during the PEO

RAI B2.39-4

GALL AMP XI.S6, "Structures Monitoring Program," element 4, notes that inspector qualifications are to be commensurate with industry codes, standards, and guidelines. ACI 349.3R-96 and ANSI/ASCE 11-90 are identified as providing an acceptable basis for addressing inspector qualifications.

Program element 4, "detection of aging effects," of the DBNPS Structures Monitoring Program notes that the structures are periodically monitored to identify degradation that could impair the functional performance of the structure. Visual inspection is the method used for monitoring the structural degradation. The inspections are performed by Maintenance Rule Walkdown Teams consisting of at least two individuals that are degreed engineers, or equivalent, and have at least five years experience in civil/structural engineering activities, or as determined by the Mechanical/Structural supervisor. At least one member of the Maintenance Rule Walkdown Team is a licensed Professional Engineer. It is unclear to the staff that personnel performing the inspections are commensurate with industry codes, standards, and guidelines for inspectors.

Provide qualifications of the personnel performing the structural inspections and show that they are commensurate with industry codes, standards, and guidelines (e.g., Section 7 of ACI 349.3R).

RAI B2.39-5

Based on recent operating experience and recent NRC reviews, the staff has determined that structures within the scope of license renewal should be monitored on a frequency not to exceed five years. This current staff position is captured in GALL Report Revision 2, AMPs XI.S5 "Masonry Walls," and XI.S6, "Structures Monitoring Program."

Program element 4, "detection of aging effects," of the DBNPS Structures Monitoring and Masonry Wall Programs note the programs periodically monitor the structures through visual inspections to identify degradation that could impair the functional performance of the structure. The standard interval between periodic assessments for a particular structure is four years, but the frequency can vary between two and ten years depending on the location and environment, susceptibility to degradation, and the age of the structure. It is unclear to the staff that the inspection frequency meets the requirements of the GALL Report.

Identify the structures and masonry walls that will be inspected on a frequency greater than five years, along with their environments and a summary of past degradation. Include a technical justification for the longer interval.

RAI B2.39-6

Based on recent operating experience and recent NRC reviews, the staff has determined that inspection programs for structures within the scope of license renewal should include quantitative limits for characterizing degradation. Chapter 5 of ACI 349.3R provides adequate acceptance criteria for concrete structures. Applicants that are not committed to ACI 349.3R and/or elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those in ACI 349.3R.

The applicant's inspection criteria used to assess the condition of structures and structural components are found in Maintenance Rule evaluation procedure for the Maintenance Rule Evaluation of Structures. Evaluation criteria follow guidance contained in NEI 96-03. Plant basis documentation identifies acceptance criteria as: Y (structure/area/room acceptable, no design basis violation, housekeeping may or may not be required), W (structure/area/room acceptable with deficiencies), and N (structure/area/room unacceptable). Little in the way of quantitative inspection criteria are provided and at least one example of criteria provided does not meet ACI 349.3R requirements (i.e., crack widths < 0.0625 in. as acceptable whereas ACI lists crack widths < 0.015 in. as acceptable). It is unclear to the staff what quantitative acceptance criteria are used and that acceptance criteria utilized comply with design basis codes and standards such as ACI 349.3R.

The staff requests the following information:

1. Provide the quantitative acceptance criteria for the Structures Monitoring and the Water-Control Structures Inspection Programs. If the concrete acceptance criteria deviate from those discussed in ACI 349.3R, provide technical justification for the differences.

2. If quantitative acceptance criteria will be added to the programs as an enhancement, provide plans and a schedule to conduct a baseline inspection with the quantitative acceptance criteria prior to the PEO.

RAI B2.39-7

During a field walkdown with the applicant's technical personnel on February 15, 2011, the NRC staff noted indications of spall repairs in two areas located on the NW side of the Shield Building near the upper right corner of the former reactor vessel head entry cut out.

This observation led to discussions relative to inspection procedures and criteria that were utilized for the Shield Building. It is unclear to the staff how inspections are performed to identify degradation such as the noted repair locations. It is also unclear how inspections of the Shield Building will be performed during the PEO and how the inspections will be used to manage aging.

Explain how aging management will be accomplished for the shield building during the PEO. Explain which AMP will be credited for aging management and why it is appropriate for the Shield Building. If visual inspections are credited, explain how the concrete will be inspected (e.g., optical aids, scaling technologies, etc., for difficult to access areas such as upper exterior elevations).

RAI B.2.39-8

NRC staff review has determined that if ASTM A325, ASTM F1852, and/or ASTM A490 bolts are used, the preventative actions as discussed in Section 2 of the Research Council for Structural Connections, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," should be followed. This recommendation is now captured in structural AMPs XI.S1, XI.S3, XI.S6, and XI.S7 of the GALL Report Revision 2.

The staff reviewed the structural AMPs in LRA Sections B.2.22, B.2.23, B.2.39, and B.2.40, as well as the associated support documents, and found no discussion of the preventative actions recommended in "Specification for Structural Joints Using ASTM A325 or A490 Bolts."

If ASTM A325, ASTM F1852, and/or ASTM A490 bolts are used, explain how the preventative actions discussed in Section 2 of "Specification for Structural Joints Using ASTM A325 or A490 Bolts" are addressed, or why they are unnecessary. The response should address all structural bolting within the scope of license renewal.

RAI B2.40-1

A review of program basis documentation related to program element 10, "operating experience," noted that during Preventive Maintenance inspections in 2007 it was discovered that the north embankment of the safety-related portion of the intake canal had settled. This settlement reduced the slope of the embankment.

It is unclear to the staff that the degradation of the embankment has been adequately addressed and that the possible aging effects will be properly managed during the PEO.

Explain how the integrity of the embankment is being ensured and how related aging effects will be addressed during the PEO.

RAI 3.6-1

In LRA Table 3.6-1, item 3.6.1-09, metal enclosed bus – enclosure assemblies, the applicant stated that loss of material due to general corrosion is not applicable to DBNPS because there is no metal enclosed bus within the scope of license renewal. During a plant walkdown, the staff reviewed the station blackout recovery path and noted that cable buses are used to connect bus tie transformers and the 4160 V essential switchgear buses. The applicant indicated to the staff that these cable buses were not subject to an AMP because they are not located in an adverse localized environment. The staff agreed with the applicant that these cable buses are not required to have an AMP because GALL Report (NUREG-1801, Revision 2) Section VI does not recommend aging management for cable in air indoor or outdoor environment. However, the cable buses are protected by enclosure assemblies. These assemblies are made from galvanized steel material.

Galvanized steel material in air outdoor or air indoor uncontrolled environment could be subject to loss of material due to general, pitting, and crevice corrosion.

Explain how aging of cable bus enclosure assemblies (including support structures) will be managed during the PEO.

RAI 3.6-2

In LRA Section 3.6.2.2.2, the applicant stated that industry experience has shown that transmission conductors do not normally swing unless subjected to a substantial wind, and they stop swinging shortly after the wind subsides. The applicant further stated that wind loading that can result in conductor sway is considered in the transmission system design. The applicant then concluded that loss of material due to mechanical wear is not an aging effect requiring management for the high voltage insulators and transmission conductors at DBNPS.

SRP Section 3.6.2.2 2 states that loss of material due to mechanical wear caused by wind blowing on transmission conductors could occur in high-voltage insulators. The applicant did not address plant-specific operating experience with high-voltage insulator and transmission conductor loss of material due to wear.

Review plant-specific operating experience and provide justification to confirm that wear has not occurred in high-voltage insulators and transmission conductors installed at DBNPS.

RAI 3.6-3

In LRA Section 3.6.2.2.3, the applicant stated that galvanized and aluminum bolted connections are exposed to the same service conditions as the plant switchyard and do not experience any aging effects, except for minor oxidation of the exterior surfaces, which does not impact their ability to perform their intended function.

Aluminum and galvanized connections are highly conductive but do not make a good contact surface since aluminum and galvanized steel exposed to air forms oxides on the inside surface which is nonconductive and could increase the resistance of connections. SRP (NUREG-1800, Revision 2) Section 3.6.2.2.3 states that increased resistance of connection due to oxidation in transmission conductors and connections, and switchyard bus and connections could occur. The SRP recommends a plant-specific program for management of increase resistance due to oxidation for transmission conductor and switchyard bus connections.

Explain why increase resistance of connections (galvanized and aluminum bolted connections) is not an aging effect requiring management and why an AMP is not needed.

RAI XI.S8-1

The GALL Report states that proper maintenance of protective coatings inside containment (defined as Service Level I in Nuclear Regulatory Commission Regulatory Guide [RG] 1.54, Revision 1) is essential to ensure operability of post-accident safety systems that rely on water recycled through the containment sump/drain system. Degradation of coatings can lead to clogging of strainers, which reduces flow through the sump/drain system.

The DBNPS LRA does not credit the protective coating monitoring and maintenance program for aging management. Although the licensee does not credit the program for aging management, there needs to be adequate assurance that there is proper management and maintenance of the protective coatings in containment, such that they will not degrade and become a debris source that may challenge the Emergency Core Cooling System and Containment Spray System performance.

The staff requests the following information:

1. Discuss why XI.S8, "Protective Coating Monitoring and Maintenance Program," is not credited for aging management.

2. Discuss in detail whether DBNPS has a coatings monitoring and maintenance program. Describe the program if one is used.

3. Describe how DBNPS will ensure that there will be proper maintenance of the protective coatings inside containment such that they will not become a debris source that could impact the operability of post-accident safety systems that rely on water recycled through the containment sump or drain system in the PEO.

If a program is used, describe the frequency and scope of the inspections, acceptance criteria, standards used, and the qualification of personnel who perform containment coatings inspections.

April 5, 2011

Mr. Barry S. Allen
Vice President, Davis-Besse Nuclear Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 1 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company (FENOC), submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54) for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station (DBNPS). The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Mr. Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,
/RA/
Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

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DATE:	04/04/2011	04/05/2011	04/05/2011	04/05/2011

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Letter to Barry S. Allen from Brian K. Harris dated April 5, 2011

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 1 (TAC NO. ME4640)

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 20, 2011

Barry S. Allen
Vice President, Davis-Besse Nuclear
 Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION–BATCH 2 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company, submitted an application pursuant to 10 *Code of Federal Regulation* Part 54 for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staffs requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,

Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

cc w/encl: Listserv

DAVIS-BESSE NUCLEAR POWER STATION
LICENSE RENEWAL APPLICATION
REQUEST FOR ADDITIONAL INFORMATION

RAI Sampling 1.0

Prior to the audit, the staff provided the applicant with a sampling of thirty-five component, material and environment combinations that were selected from license renewal application (LRA) Table 3. These components were chosen at random, in order to give the staff assurance that the information provided in the aging management review results in the applicant's LRA was accurate. The staff notes that accurate identification and independent confirmation of material and environment combinations is necessary to support the applicant's aging management reviews.

During the Scoping and Screening audit, on January 25, 2011, the staff performed a walkdown to confirm if the selected component, material and environment combinations listed in the LRA were accurate. After the completion of the walkdown the staff noted the following:

1. An orifice (component ID DB-RO4989) in the high-pressure injection system (LRA Table 3.2.2-5), exposed to an environment of lubricating oil (internal), was identified as being fabricated from steel. During the walkdown of the system and component, the staff noted that the material was incorrectly identified as steel.

2. Tubing (drain tubing from component ID DB-F86) in the station air system (LRA Table 3.3.2-29), exposed to an environment of air-indoor uncontrolled (external), was identified as being fabricated from steel. During the walkdown of the system and component, the staff noted that the material was incorrectly identified as steel.

The staff requests the following information:

1. The staff requests that the applicant verify the material composition of the components described above and, if necessary, provide an updated aging management review, in accordance with 10 CFR 54.21(a)(1).

2. Based on the identification that the materials of these two components were incorrectly identified in the LRA, clarify the follow-up actions that have been or will be taken to ensure that the aging management review (AMR) results in the LRA are accurate.

RAI 3.3.2.2.5-1

In the LRA, the applicant lists at least 24 Table 2 AMR line items that address elastomeric components exposed to an air-indoor uncontrolled (internal and external), raw water (internal) or treated water >60°C (>140°F) (internal) being managed for hardening and loss of strength by the External Surfaces Monitoring Program supplemented by the One-Time Inspection Program or the One-Time Inspection Program. These line items include, but are not limited to:

- 3.2.2-1, Row 21;
- 3.3.2-6, Row 4; and
- 3.3.2-28, Row 5.

The applicant also lists several line items that address elastomeric components exposed to an air-outdoor, air-indoor, or soil environment being managed for cracking and change in material properties by the Structures Monitoring Program.

LRA Section B.2.15 states that the External Surfaces Monitoring Program consists of periodic visual inspections and surveillance activities. It also states that the acceptance criterion for elastomeric materials is no unacceptable visual indications of cracks or discoloration. LRA Section B.2.30 states that the One-Time Inspection Program will include visual and physical examination, such as manipulation and prodding, of elastomers (flexible connections).

For AMR line items addressing similar material, environment, and aging effects, the Generic Aging Lessons Learned (GALL) Report recommends a periodic inspection program.

Consistent with the GALL Report, one-time inspections are appropriate for managing loss of material where environments are consistent with time such as the fuel oil, lube oil, and water chemistry programs. Where environments may not be consistent with time, such as indoor air or outdoor air, the GALL Report recommends the performance of periodic inspections since a single inspection may not reflect, or predict, the existence of future degradation.

The staff has the following concerns:

- It is not clear to the staff whether only the One-Time Inspection Program will be used to inspect elastomeric components exposed to an air-indoor uncontrolled (internal and external), or if both the External Surfaces Monitoring and One-Time Inspection Programs will be used. The staff noted that for the elastomeric components exposed to raw water and treated water >60°C (>140°F), only the One-Time Inspection Program is credited.
- The External Surfaces Monitoring Program and the Structures Monitoring Program do not include physical manipulation of elastomeric materials and therefore it may not be fully effective at determining if hardening or loss of strength has occurred.
- The staff lacks sufficient information (e.g., thickness of flexible connections and mechanical sealants) to determine whether the inspection of the elastomeric components will detect hardening and loss of strength on the interior surfaces of the component.

The staff requests the following information:

1. Given that the One-Time Inspection Program would not be an effective program for managing hardening and loss of strength for elastomeric components exposed to an

air-indoor uncontrolled (internal and external), raw water (internal) or treated water >60°C (>140°F) (internal), provide details as to what alternative program will be applied to appropriately manage the aging for these material and environment combinations.

2. Provide an assessment of those Table 2 AMR line items containing similar material, environment, and aging effect combinations that might be similarly affected and revise these line items to ensure an appropriate aging management program.

3. If as a result of the response to requests (1) and (2), or due to existing AMR line items, the External Surfaces Monitoring Program or Structures Monitoring Program is used to manage aging of elastomeric components, revise the programs to include physical manipulation of elastomeric materials, or state how they would be effective at determining if hardening or loss of strength has occurred.

4. State the basis for how hardening and loss of strength occurring on the interior surfaces of elastomeric components will be effectively detected with only an inspection of the exterior surface of the component.

RAI 3.3.2.71-2

In the LRA, the applicant lists at least at 41 Table 2 AMR line items that address steel piping and piping components exposed to air (internal), condensation (internal), and moist air (internal) all with an aging effect of loss of material, and all assign the One-Time Inspection Program as the aging management program. These line items include, but are not limited to:

- 3.3.2-12, Row 91,
- 3.3.2-1, Row 34, and
- 3.3.2-31, Row 25.

For AMR line items addressing similar material, environment, and aging effects, the GALL Report recommends a periodic inspection program such as the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program to manage aging effects for these component/material/environment combinations.

Consistent with the GALL Report, one-time inspections are appropriate for managing loss of material where environments are consistent with time such as the fuel oil, lube oil, and water chemistry programs. Where environments may not be consistent with time, such as indoor air or outdoor air, the GALL Report recommends the performance of periodic inspections since a single inspection may not reflect, or predict, the existence of future degradation. Therefore, it is unclear why the applicant has selected the One-Time Inspection Program to manage a loss of material aging effect instead of a program that conduct's periodic inspections.

The staff requests the following information:

1. Given that the One-Time Inspection Program would not be an effective program for managing a loss of material for steel piping and piping components exposed to air (internal), condensation (internal), and moist air (internal), provide details as to what alternative program will be applied to appropriately manage the aging for these material and environment combinations.

2. Provide an assessment of those Table 2 AMR line items containing similar material, environment, and aging effect combinations that might be similarly affected and revise these line items to ensure an appropriate aging management program.

RAI B.2.2-1

The "detection of aging effects" program element of GALL Report aging management program (AMP) XI.M29 "Aboveground Steel Tanks" recommends that potential corrosion of in-scope tank bottoms be determined by conducting thickness measurements whenever the tank is drained and at least once within five years of entering the period of extended operation. LRA Section B.2.2 states that volumetric examination of tank bottoms will be conducted prior to the period of extended operation and that the frequency tank bottom volumetric inspections will be based on the findings of the inspection performed prior to the period of extended operation. It is not clear to the staff that, as a minimum, in-scope tank bottom thickness measurements will be performed whenever the tanks are drained and at least once within five years of entering the period of extended operation.

The staff requests the following information:

1. State the minimum number of times each in-scope tank's bottom will be inspected for thickness during the period of extended operation.

2. Revise LRA Appendix A, "Updated Safety Analysis Report Supplement," Section A.1.2, "Aboveground Steel Tanks Inspection Program," to reflect the fact that in-scope tank bottom thickness measurements will be performed whenever the tanks are drained and at least once within five years of entering the period of extended operation.

RAI B.2.2-2

LRA Table 3.2.2-4, row number 117 states that for the stainless steel borated water storage tank exposed to air-outdoor (external) there is no aging effect and no AMP is proposed. The on-site AMP walkdown revealed that the tank is coated with insulation material.

It is the staff's position that cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, piping elements, and tanks exposed to certain outdoor air environments. Such environments include, but are not limited to, those within 1/2 mile of a highway which is treated with salt in the wintertime, areas in which the soil contains more than trace chlorides, plants having cooling towers where the water is treated with chlorine or chlorine compounds, and areas subject to chloride contamination from other agricultural or industrial sources. In addition, although updated final safety analysis report (UFSAR) Section 5.2.3.3 states that the insulation coating the stainless steel borated water storage tank is compatible with the material of construction, there is no information in the LRA or UFSAR on the susceptibility of the insulation to release chlorides which could result in cracking of the stainless steel tank material.

The staff requests the following information:

1. State why the air-outdoor environment will not result in an aging effect requiring management for the stainless steel borated water storage tank (e.g., exposure to chlorides in the atmosphere, road chemical treatments, soil containing more than trace chlorides, cooling tower chemical treatment, local agricultural or industrial sources that could result in chloride contamination).

2. Describe the insulation material applied on the external surface of the stainless steel borated water storage tank and state if it could release halides.

3. If the air-outdoor environment or leached compounds from the insulation could result in an aging effect requiring management, state how the aging effect will be managed.

RAI B.2.2-3

The "preventive actions" program element of GALL AMP XI.M29 "Aboveground Steel Tanks" states that sealant or caulking at the external interface between the tank and concrete or earthen foundation mitigates corrosion of the bottom surface of the tank by minimizing the amount of water and moisture penetrating the interface, which would lead to corrosion of the bottom surface. LRA Section B.2.2 does not state that sealant or caulking was utilized at the external interface between the tank and concrete or earthen foundation.

It is not clear to the staff whether the firewater storage tank, diesel fuel oil storage tanks, and borated water storage tank have sealant or caulking installed at the external interface between the tank and concrete or earthen foundation. It is also not clear to the staff what compensatory measures are being implemented by the applicant to effectively manage aging of the bottom surface of the tanks if sealant or caulking was not installed at the base.

The staff requests the following information:

1. State whether the firewater storage, diesel fuel oil storage, and borated water storage tanks have sealant or caulking installed at the external interface between the tank and concrete or earthen foundation.

2. If these tanks do not have sealant or caulking, revise LRA B.2.2 to state and justify this as an exception to GALL AMP XI.M29.

3. If the tanks do have sealant or caulking, how will their aging effects be managed?

RAI B.2.2-4

LRA Section B.2.2 states that an inspection of the exterior of the diesel oil storage tank in 2002 revealed rust and corrosion at the base flange of the tank and corroded bolted at the lower access plate at the base of the tank.

The applicant did not state the cause of corrosion on the external surface of the tank. State the cause(s) for the external tank surface corrosion that occurred in 2002 associated with the diesel oil storage tank and what extent of condition review was conducted. State how this plant-specific operating experience was incorporated into the Aboveground Steel Tanks Inspection program.

RAI B.2.4-1

GALL AMP XI.M18, "Bolting Integrity," recommends preventive actions and inspections for managing the aging of bolting within the scope of license renewal including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including nonsafety-related bolting, and 4) structural bolting (actual measured yield strength > 150ksi). GALL AMP XI.M18 further states that other aging management programs also manage inspection of safety-related bolting and supplement this Bolting Integrity program.

LRA Section B.2.4, "Bolting Integrity," states that the Bolting Integrity program inspections are implemented through the following other aging management programs: Inservice Inspection - IWE; Inservice Inspection – IWF; and Structures Monitoring Program. LRA Sections B.2.22, "Inservice Inspection (ISI) Program- IWE," B.2.23, "Inservice Inspection Program- IWF," and B.2.39, "Structures Monitoring Program," do not include bolting in their program descriptions.

The applicant's B.2.22, B.2.23, and B.2.39 program basis documents do not provide guidance for aging effects related to bolting, associated preventive actions, or recommended inspections. The applicant states in their LRA that the ISI-IWE, ISI-IWF, and Structures Monitoring programs supplement the Bolting Integrity program by implementing inspections of structural bolts.

However, neither the LRA nor the applicant's ISI-IWE, ISI-IWF, and Structures Monitoring program basis documents provide guidance for aging effects related to structural bolting, associated preventive actions, or recommended inspections. The lack of guidance in the LRA and program basis documents brings into question the ability of these programs to manage bolting related aging effects including loss of material, loss of preload, cracking and stress corrosion cracking.

Describe how GALL AMP XI.M18 recommendations in the "preventive actions," "parameters monitored," and "detection of aging effects" program elements are addressed for bolting in the ISI-IWE, ISI-IWF and Structures Monitoring Programs. Include the specific inspection technique utilized by each program to manage loss of material, loss of preload, cracking and stress corrosion cracking. If volumetric or surface examinations are not conducted for SCC susceptible bolts, explain why it is unnecessary.

RAI B.2.4-2

GALL AMP XI.M18, "Bolting Integrity," relies on recommendations for a comprehensive bolting integrity program as delineated in EPRI TR-104213, EPRI NP-5769 and NUREG-1339. LRA section B.2.4 states an exception to the GALL AMP XI.M18, indicating that the applicant does not explicitly address the guidelines outlined in EPRI NP-5769 and NUREG-1339. Instead, the applicant's Bolting Integrity Program only relies on the recommendations contained in EPRI TR-104213 and EPRI TR-111472.

The use of EPRI TR-111472 as guidance in place of the GALL recommended guidance delineated in EPRI NP-5769 and NUREG-1339 requires further clarification to determine how EPRI TR-111472 meets the intent of EPRI NP-5769 and NUREG-1339 as identified in GALL AMP XI.M18, and whether or not its usage will contradict the GALL guidance.

Provide clarification on the use of EPRI TR-111472 as guidance for this program. Specifically, provide an explanation of any contradictions between EPRI TR-111472 and the GALL recommended guidance delineated in EPRI NP-5769 and NUREG-1339 that it is replacing and their impact on this program.

RAI B.2.4-3

GALL AMP XI.M18 "Bolting Integrity" indicates that use of molybdenum disulfide (MoS_2) as a lubricant on closure bolting within the scope of license renewal is a potential contributor of stress corrosion cracking and should not be used. The applicant's Bolting Integrity program basis documents state that certain instances were identified where lubricants containing MoS_2 were approved for use, but the operating experience review did not show cases where lubricants had caused degradation.

The use of MoS_2 is known to be a contributor to stress corrosion cracking and should not be used. The extent of usage of MoS_2 as a lubricant on closure bolting within the scope of license renewal is not clear. It is also not clear if the applicant will be replacing lubricants containing MoS_2 with an alternate lubricant for use on closure bolting within the scope of license renewal.

The staff requests the following information:

1. Identify the extent to which MoS_2 is currently used as a lubricant on closure bolts within the scope of license renewal.

2. Are there plans to replace MoS_2 with an alternate lubricant for use on closure bolting within the scope of license renewal? If no replacement is planned, the staff would consider this to be an exception to the recommendations of GALL AMP XI.M18 requiring an appropriate justification as to why stress corrosion cracking would not be of concern.

RAI B.2.7-1

LRA Section B.2.7 states that the Buried Piping and Tanks Inspection Program, is an existing program with no exceptions and eight enhancements, and is consistent with GALL AMP XI.M34. In light of recent industry operating experience, the staff is concerned about the continued susceptibility to failure of buried piping that is within the scope of 10 CFR 54.4 and subject to aging management for license renewal. Most of the events could have been avoided with the effective implementation of one or more preventive actions consisting of cathodic protection, effective coatings and quality of backfill. The staff integrated this operating experience into the recommendations contained in GALL AMP XI.M41, "Buried and Underground Piping and Tank Inspections."

The staff identified the following issues:

1. In order to evaluate an applicant's buried pipe and underground piping inspection programs, the staff must be aware of plant-specific operating experience which might include examples beyond those listed in the LRA.

2. GALL AMP XI.M41 Sections 4.b.iii. and 4.c.iii. state that inspection locations should be risk informed based on susceptibility to degradation and consequence of failure. The staff does not have sufficient information to determine if the applicant will utilize risk informed criteria to inspection locations.

3. GALL AMP XI.M41, Table 2a, states that buried in-scope steel piping should be cathodically protected. The LRA and UFSAR do not contain enough details to determine if the buried in-scope service water piping is cathodically protected. In addition, UFSAR 9.5.4.2 states, "Corrosion of the tanks [fuel oil storage] will be prevented by protective coatings, and by cathodic protection if necessary." Therefore it is not clear to the staff if the fuel oil tanks are cathodically protected. The LRA does not state the availability of the cathodic protection system and what periodic testing is conducted on the cathodic protection system.

4. GALL AMP XI.M41, Table 2a, states that the backfill within six inches of buried in-scope steel piping should meet Section 5.2.3 of NACE SP0169-2007. The LRA does not describe the quality of the backfill in the vicinity of buried in-scope piping.

5. GALL AMP XI.M41, Table 2a, states that steel piping should be coated; however, if a buried fire protection piping system was designed to NFPA-24 and is tested to NFPA-25, then the coating preventive measures of Table 2a does not apply. The staff noted that UFSAR, Table 9.0-1 states that the fire protection piping and components were installed to NFPA requirements, but it did not specify NFPA-24. The staff also noted that LRA Section B.2.1.18 (Fire Water Program) states that periodic flow testing is conducted in accordance with NFPA-25, but also states that some portions are not flow tested. The

staff does not have sufficient information to determine that the buried in-scope fire protection piping was constructed to NFPA-24 and is periodically tested to the requirements of NFPA-25.

6. LRA Section B.2.7 describes two instances of coating degradation, a 1995 example associated with a fuel oil piping leak and a 2008 example associated with a condensate demineralizer backwash line. The applicant did not state the cause of the coating degradation. In addition, the LRA describes the discovery of four different coating holidays. The staff needs to understand the causes of the failures in order to evaluate the effectiveness of the applicant's program.

7. Enhancements three through six state that one inspection of a buried in-scope coated and wrapped piping segment or tank, and one inspection of uncoated cast iron piping will be conducted in the ten-year period prior to extended operation and be repeated once in the first ten-year period of extended operation. The sample size proposed by the applicant may not provide a reasonable basis for assurance that the piping will meet its intended license renewal function(s) if a piping system is not cathodically protected.

8. LRA Section B.2.7 and Commitment No. 3 state that approximately ten linear feet of piping will be exposed for inspections. The staff believes that a minimum inspection length should be established to ensure that an adequate length of piping is inspected.

9. The staff reviewed LRA Section A.1.7 and UFSAR Update for the Buried Piping and Tanks Inspection Program and noted that it does not state that preventive measures are in accordance with standard industry practice for maintaining external coatings and wrappings and cathodic protection.

10. Given that the LRA Section B.2.7 describes a 1995 fuel oil leak, 2002 holiday (i.e., location of missing coating) in a fuel oil line, 2008 fuel oil line holidays leading to pitting and minor corrosion, and a 2008 condensate demineralizer backwash line coating damage, it is not clear to the staff how the applicant is informing the number of required inspections based on plant-specific operating experience. GALL AMP XI.M41, Section 4.f.iv. states that if adverse conditions (e.g., leaks, material thickness less than minimum, presence of coarse backfill within six inches of the pipe that resulted in coating degradation, general or local degradation that resulted in exposure of the base material) are discovered during the inspection of in-scope buried pipe, that the sample size is doubled and if subsequent inspections find further adverse conditions that the inspection size continues to be doubled. LRA Section B.2.7 states that degradation or leakage found during inspections is entered into the corrective action program to ensure evaluations are performed and appropriate corrective actions are taken, but it does not state the expansion of scope size.

11. LRA Section B.2.20, Fuel Oil Chemistry Program, states that the effectiveness of the Fuel Oil Chemistry Program is verified by the One-Time Inspection program, which includes ultrasonic thickness measurement of a sample fuel oil tank bottom to ensure that significant degradation is not occurring. If the fuel oil tanks are cathodically protected, the staff believes that to effectively detect aging effects of a buried tank each fuel oil tank should have a periodic internal visual inspection and if the visual inspection detects signs of degradation on the surfaces of the tank, a volumetric examination on the interior surfaces of the tank should be conducted.

12. LRA Table 3.3.2-12, row number 102, states that there is steel piping external exposed to soil. It is not clear whether the internal environment is fuel oil, lubricating oil, or air.

13. LRA Section B.2.15, External Surfaces Monitoring Program, states that, "Surfaces that are inaccessible or not readily visible during either plant operations or refueling outages, such as surfaces that are insulated, will be inspected opportunistically during the period of extended operation." Based on a review of the LRA, it is not clear to the staff which systems have underground piping or tanks (i.e., below grade but are contained within a tunnel or vault such that they are in contact with air and are located where access for inspection is restricted) and the length of piping or number of tanks that are underground. GALL Report AMP XI.41 recommends a minimum number of inspections of underground piping based on material type and function of the piping (i.e., code class/safety-related, contains hazardous materials) and each steel tank. Given the "opportunistic" statement in the LRA, it is not clear to the staff that the applicant's program will inspect an adequate sample of underground piping and tanks. In addition, GALL AMP XI.M41, Section 4.c.iv., states that underground piping is visually inspected to detect external corrosion and volumetrically examined to detect internal corrosion. The staff does not have sufficient information to determine if and to what extent the applicant will conduct volumetric examinations of underground piping.

14. GALL AMP XI.M41, Table 2b, states that underground piping should be coated in accordance with Table 1 of NACE SP0169-2007 or the applicant should justify the alternative coating methodology. The staff does not have sufficient information to determine if the applicant's coatings for underground piping meet Table 1 of NACE SP0169-2007 Table 1.

15. GALL AMP XI.M41, Section 6.c, states that, if coated or uncoated 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. LRA Section B.2.7 states that degradation found during inspections is entered into the corrective action program to ensure evaluations are performed and appropriate corrective actions are

taken, but it does not state the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained.

The staff requests the following information:

1. Provide a list and brief summary, including cause, of any leaks or adverse conditions (e.g., leaks, material thickness less than minimum, presence of coarse backfill within six inches of the pipe that resulted in coating degradation, general or local degradation that resulted in exposure of the base material) which have occurred in buried piping or tanks at the station in the past five years that were entered in your corrective action program but are not included in your LRA.

2. State whether buried and underground in-scope piping inspection locations will be selected based on risk factors considering susceptibility to degradation and consequences of failure. If inspection locations are not risk informed, state how the inspections that are conducted will be representative of piping locations that are most susceptible to degradation and result in the worst adverse consequences.

3. For buried in-scope steel piping respond to the following:

    i. State whether the service water system and emergency diesel generator fuel oil storage tanks are cathodically protected, including, if portions of a system are protected, what portions are not protected.

    ii. State the availability of the cathodic protection system, and if portions of the system are not available 90% of the time or will be allowed to be out of service for greater than 90 days in any given year, state how the piping will meet or exceed the minimum design wall thickness throughout the period of extended operation.

    iii. State whether annual ground potential surveys of the cathodic protection system are conducted and what acceptance criteria is utilized, or if annual ground potential surveys are not conducted, state how the piping will meet or exceed the minimum design wall thickness throughout the period of extended operation.

    iv. State what cathodic protection system inspection/testing parameters will be trended and evaluated for adverse changes. If these parameters do not include potential difference and current measurements state how the effectiveness of the systems and/or coatings will be evaluated.

4. Based on plant-specific installation specifications and the results of inspections conducted to date, state if the backfill within six inches of buried in-scope steel piping meets NACE SP0169-2007. If the backfill does not meet NACE SP0169-2007, state how the buried pipe coatings will not be potentially damaged by the backfill.

5. State the following for buried in-scope uncoated fire protection cast iron piping:

   i. What specific NFPA code was used for the design and installation of the in-scope buried fire protection piping. If the design and installation code required that cast iron piping be coated, state why there is a reasonable assurance that the uncoated cast iron piping will meet its current CLB function(s) throughout the period of extended operation.

   ii. State whether all portions of the buried in-scope fire protection piping will be periodically flow tested in accordance with NFPA-25. If all or some portions of the buried in-scope fire protection piping will not be periodically flow tested in accordance with NFPA-25, state why there is a reasonable assurance that the uncoated cast iron piping will meet its current CLB function(s) throughout the period of extended operation.

6. State the cause for the coating degradation that occurred in a 1995 example associated with a fuel oil piping leak and a 2008 example associated with a condensate demineralizer backwash line. State the basis for having a reasonable assurance that planned inspections represent an adequate quantity to identify coating damage and holidays before leaks occur.

7. For buried in-scope piping, respond to the following:

   i. What minimum number of inspections of buried in-scope piping is planned during the 30 – 40, 40 – 50, and 50 – 60 year operating period? When describing the minimum number of planned inspections, differentiate between material, code/safety-related piping, and potential to contain hazardous material category piping inspection quantities of buried in-scope piping.

   ii. State which inspections will be conducted by excavated direct visual inspection of the buried piping.

   iii. State the length of each buried in-scope piping system.

   iv. If there are no planned inspections for piping containing hazmat materials, state why it is acceptable to not inspect in-scope pipe containing hazardous materials.

8. State the minimum inspection length of excavated buried piping inspections. If the length is shorter than ten feet, state the basis for why this length will provide an adequate representative length of piping. Revise LRA Commitment No. 3 to state the minimum inspection length of piping.

9. Revise LRA Section A.1.7 to state that preventive measures are in accordance with standard industry practice for maintaining external coatings/wrappings and cathodic protection, and state the number of inspections and frequency of buried in-scope piping.

10. State the sample size increase of the inspection in-scope buried pipe that will occur if adverse conditions (e.g., leaks, material thickness less than minimum, presence of coarse backfill within six inches of the pipe that resulted in coating degradation, general or local degradation that resulted in exposure of the base material) are discovered during inspections. If the inspection sample size is not initially doubled and then doubled again if adverse conditions are discovered in the initial and subsequent inspections, state why there is a reasonable assurance that the extent of condition has been discovered and evaluated.

11. For the buried in-scope steel fuel oil tanks state whether each fuel oil tank will have a periodic internal visual inspection and if the visual inspection detect signs of degradation on the surfaces of the tank, a volumetric examination on the interior surfaces of the tank will be conducted, or state why it is acceptable to not conduct these inspections. In addition, state the frequency of inspection of the tanks. If the frequency of tank inspections exceeds ten years, state the basis for why the test frequency provides a reasonable assurance that the tank will not leak or be able to meet its CLB function(s).

12. State whether the piping in LRA Table 3.3.2-12, row number 102, has an internal environment of fuel oil, lubricating oil, or air.

13. State the systems, function (e.g., safety related, Code required, contains hazmat material, nonsafety-related), material type and length of in-scope underground piping and state the number of underground steel tanks. State how many and the extent of visual and volumetric inspections that will be conducted of underground piping and steel tanks.

14. State whether underground piping and tanks are coated in accordance with Table 1 of NACE SP-0169-2007 or justify why the existing coating or lack of coating provides a reasonable assurance that the uncoated piping will meet its current CLB function(s) throughout the period of extended operation.

15. If coated or uncoated metallic piping or tanks show evidence of corrosion, state whether the remaining wall thickness in the affected area will be determined to ensure that the minimum wall thickness is maintained. If the remaining wall thickness will not be measured, state how there is reasonable assurance that the extent of corrosion is understood.

RAI B.2.8-1

In the program description for LRA Section B.2.8, the applicant stated that the Closed Cooling Water Chemistry Program will be supplemented by the One-Time Inspection Program; however, in the exception for this program, the applicant stated that opportunistic inspections will be conducted. The GALL AMP XI.M21 "Closed-Cycle Cooling Water System" element 4 "detection of aging effects" states that the control of water chemistry does not preclude corrosion or stress corrosion cracking and that the extent and schedule of inspections and testing should assure detection of these aging effects before the loss of the intended function.

Based on the program description in LRA Section B.2.8, it is unclear to the staff whether the applicant will conduct a one-time inspection, periodic inspections of opportunity, or a combination of the two, as the description of the inspection activity differs within the program summary.

The guidance in the GALL Report maintains that one-time inspections should not be used for structures or components with known age-related degradation mechanisms or when the environment is not consistent with time. In these cases, periodic inspections are recommended where a single inspection may not reflect, or predict, the lack of degradation in the future. It is the staff's current position that inspections conducted in conjunction with the closed-cycle cooling water systems should be conducted whenever the system is opened and that a representative sample of piping and components should be inspected at an interval not to exceed ten years.

The staff requests the following information:

1. Confirm whether the program will include a one-time inspection, periodic inspections of opportunity, or a combination of the two.

2. If periodic inspections will not be conducted, provide technical justification for the selection of the One-Time Inspection Program rather than a program that uses periodic inspections.

3. If periodic inspections will be conducted, state whether the inspection results will be reviewed to ensure that a representative sample of piping and components has been inspected at an interval not to exceed ten years. Absent a minimum inspection interval, state how inspections of opportunity will provide assurance that corrosion or stress corrosion cracking will be detected before the component's loss of intended function.

RAI B.2.10-1

Standard Review Plan (SRP)-LR Rev. 2, Table 3.0-1, provides the recommended FSAR Supplement Description for GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The SRP-LR recommends the following wording: "The number and magnitude of lifts made by the hoist or crane are also reviewed."

The Davis-Besse LRA Updated Safety Analysis Report Supplement Section A.1.10, "Cranes and Hoists Inspection Program" description does not address a review of the number and magnitude of lifts made by a hoist or crane.

Update the UFSAR Supplement wording to reflect the fact that the Cranes and Hoists Inspection Program includes a review of the number and magnitude of lifts made by a hoist or crane.

RAI B.2.10-2

GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems," scope of program states that this program manages the effect of loss of preload of bolted connections. Bolted connections are also addressed in elements 3, 4, and 10 of this AMP.

During the audit, the staff reviewed the applicant's B.2.10 Cranes and Hoists Inspection Program and its references and found that although loss of preload of bolted connections for cranes and hoists is addressed in the program inspections and preventive maintenance procedures, it is not included in the LRA program description or other program elements nor are there any AMR line items addressing a loss of preload of bolted connections for overhead cranes and hoists.

The staff requests the following information:

1. If the Cranes and Hoist Inspection AMP is intended to be used to manage a loss of preload for bolted connections of cranes and hoists, revise the LRA and associated programs elements to reflect this.

2. Clarify why crane and hoist program inspections and preventive maintenance procedures discuss loss of preload as an aging effect despite the fact that there are currently no AMR line items related to a loss of preload for bolted connections for overhead cranes and hoists.

RAI B.2.16-1

LRA Section B.2.16, "Fatigue Monitoring Program," states that it manages fatigue of select primary and secondary components, including the reactor vessel, reactor internals, pressurizer, and steam generators, by tracking thermal cycles as required by Technical Specification (TS) 5.5.5, "Component Cyclic or Transient Limit." LRA Section 4.3 states that the 14 original design transients for the RCS are found in USAR Table 5.1-8. Furthermore, the design cycles that are significant contributors to fatigue usage are included in the Fatigue Monitoring Program and are provided in LRA Table 4.3-1.

The staff reviewed the applicant's program implementation procedure for tracking transients during its on-site audit. After reviewing the applicant's procedure, TS 5.5.5, USAR Table 5.1-8, and LRA Table 4.3-1 the staff noted that various transients, descriptions, and cycle counts were not consistent with each other. In order to verify which transients are monitored and are fatigue-significant, the connection between the applicant's procedure, LRA Table 4.3-1, TS 5.5.5, and the USAR need to be consistent.

The staff noted that TS 5.5.5, Amendment 279 (Adams Accession No. ML053110490), was titled "Allowable Operating Transient Cycles Program," which is not consistent with the title "Component Cyclic or Transient Limit" as described in LRA Section B.2.16. It is not clear to the staff which revision of TS 5.5.5 is currently in place.

The staff requests the following information:

1. Clarify and justify the discrepancies between the program implementation procedure, TS 5.5.5, USAR Table 5.1-8, and LRA Table 4.3-1 with respect to the transient descriptions, transients monitored, and all cycle limits. In lieu of a justification, amend the appropriate documents such that the transients being monitored by the Fatigue Monitoring Program and the transients used in the related fatigue time-limited aging analyses (TLAAs) are consistent (e.g., TS, USAR, LRA and program implementation procedure). Clarify if there are transients that require monitoring by TS 5.5.5 and USAR Section 5 that are not or will not be monitored by the Fatigue Monitoring Program. If these types of transients exist, justify why these transients do not need to be monitored currently and during the period of extended operation, as required by TS 5.5.5 and USAR Section 5. Update USAR Section 5, as needed, to ensure that the basis for not monitoring these required transients is documented.

RAI B.2.16-2

The "scope of program" program element of GALL (NUREG 1801, Rev. 2) AMP X.M1 recommends that the program should include, for a set of sample reactor coolant system components, fatigue usage calculations that consider the effects of the reactor water environment. This sample set should include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they may be more limiting than those considered in NUREG/CR-6260.

During its audit and review of LRA Section B.2.16, "Fatigue Monitoring Program," and supporting program basis documents, the staff did not find any identification of additional component locations other than those from NUREG/CR-6260, or a confirmation that the NUREG/CR-6260 locations were bounding for the applicant's site. Furthermore, the staff noted that the applicant's plant-specific configuration may contain locations that should be analyzed for the effects of the reactor coolant environment other than those identified in NUREG/CR-6260. This may include locations that are limiting or bounding for a particular plant-specific configuration, or that have calculated cumulative usage factor (CUF) values that are greater when compared to the locations identified in NUREG/CR-6260.

The staff requests the following information:

1. Justify that the plant-specific locations listed in LRA Table 4.3-2 are bounding for the generic NUREG/CR-6260 components.

2. Confirm and justify that the locations selected for environmentally assisted fatigue analyses in LRA Table 4.3-2 consists of the most limiting locations for the plant (beyond the generic components identified in the NUREG/CR-6260 guidance). If these locations are not bounding, clarify the locations that require an environmentally assisted fatigue analysis and the actions that will be taken for these additional locations. If the identified limiting location consists of nickel alloy, state whether the methodology used to perform the environmentally-assisted fatigue calculation for nickel alloy is consistent with NUREG/CR-6909. If not, justify the method chosen.

RAI B.2.16-3

LRA Section B.2.16, "Fatigue Monitoring Program," states that it uses the systematic counting of plant transient cycles to ensure that the design cycles are not exceeded, thereby ensuring that component fatigue usage limits are not exceeded. The acceptance criterion is to maintain the number of counted transient cycles below the design cycles for each transient.

The preventive actions" program element of GALL (NUREG 1801, Rev. 2) AMP X.M1 recommends the program to ensure that the fatigue usage does not exceed the Code design limit of 1.0. The number of actual plant transients exceeding the numbers used in the fatigue analyses or the actual transient severity exceeding the bounds of the design transient definitions can cause the fatigue usage to exceed the Code design limit.

The "detection of aging effects" program element of GALL (NUREG 1801, Rev. 2) AMP X.M1 recommends that the fatigue monitoring program provide for periodic updates of the fatigue usage calculations, on as-needed basis, if an allowable cycle limit is approached. The staff noted that this ensures that the fatigue usage calculations remain valid and the Code design limit is not exceeded.

Based on the applicant's description of the Fatigue Monitoring Program, it only keeps track of cycle counts; therefore, it is not clear to the staff how the applicant's program confirms that the severity of actual transients is bounded by the severity assumed in the design analysis. Also, it is not clear how the program accounts for any differences in the number of "design cycles," as listed in LRA Table 4.3-1, and the number of cycles that were used in a fatigue analyses.

During its audit, the staff noted that the applicant's plant procedure, implementing the Fatigue Monitoring Program, describes that, when the count for a transient reaches a certain fraction of the corresponding "design cycles," Design Engineering is contacted for re-evaluation of the allowed cycles. However, the specific actions that would be taken, and in what timeframe, with regard to the updating of allowable cycles, or an alternate course of action, were not discussed. There may be a potential for exceeding the number of cycles used in the analysis if they are less than the "design cycles" listed in LRA Table 4.3-1.

The staff requests the following information:

1. Provide the details and basis for the process used to verify that the severity of an actual transient is bound by the severity of the design transient. If this process is not in place,

justify how the actual severity of a transient is confirmed to be bounded by the design severity, to ensure that the fatigue analysis remains valid.

2. Confirm that the severity of all transients that have occurred to date, since initial plant operation, have been bounded by the design severity. If there have been instances where the actual severity exceeded the design severity, discuss the actions taken to assure that the Code design limit has not been exceeded and that the fatigue analysis remains valid.

3. Confirm that the "design cycles" monitored by the Fatigue Monitoring Program," are in fact the ones used in the fatigue analysis. If not, justify why the "design cycles" listed in LRA Table 4.3-1 are monitored by the Fatigue Monitoring Program, to ensure that the fatigue usage limit is not exceeded in a given analysis.

4. Clarify the actions or measures taken as part of the Fatigue Monitoring Program if the actual transient severity exceeds the design severity and if the actual cycle count approaches or exceeds the number of cycles used in the analysis.

RAI B.2.16-4

LRA Section B.2.16, "Fatigue Monitoring Program," proposes an enhancement to the "preventive action" program element which states that for locations, including NUREG/CR-6260 locations, projected to exceed a CUF of 1.0, the program may implement an option that will "manage the effects of aging due to fatigue at the affected locations by an inspection program that will be reviewed and approved by the Nuclear Regulatory Commission (NRC) (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method acceptable to the NRC)."

The objective of GALL AMP X.M1 is to ensure that the fatigue usage does not exceed the Code design limit during period of extended operation. It is not clear to the staff how the proposed option of managing the aging due to fatigue by an inspection program is consistent with the objective in GALL AMP X.M1, to prevent cumulative fatigue usage from exceeding the Code design limit.

Furthermore, the enhancement implies that it encompasses all locations, including the NUREG/CR-6260 specific locations. However, during its audit, the staff noted that this enhancement may only be applicable to the NUREG/CR-6260 specific locations.

The staff requests the following information:

1. Provide the basis for using an inspection program, as an option, to manage fatigue usage for during period of extended operation.

2. Clarify how the use of an inspection program is consistent with the objective of GALL AMP X.M1, to maintain fatigue usage below the Code design limit. Clarify how the use of this option will be used as a preventative action and how this is consistent with the "preventive action" program element. Clarify if the options described in the

enhancement are meant to be corrective actions if the Fatigue Monitoring Program provides indications that the CUF may exceed 1.0.

3. Clarify if the options described in this enhancement are applicable only for the NUREG/CR-6260 locations, and, if so, specify and justify the actions taken if the CUF exceeds 1.0 for all other locations.

RAI B.2.16-5

LRA AMP B.2.16, "Fatigue Monitoring Program," includes an enhancement to the "parameters monitored and inspected" program element of GALL AMP X.M1 which states "The Fatigue Monitoring Program will be enhanced to monitor any transient where the 60-year projected cycles were used in an environmentally-assisted fatigue evaluation and to establish an administrative limit that is equal to or less than the 60-year projected cycles."

The need for the first part of this enhancement is not clear to the staff since consistency with the GALL AMP X.M1 ensures monitoring of all plant transients that are fatigue-significant and not just those transients where the 60-year projected cycles were used in an environmentally-assisted fatigue evaluation.

The second part of this enhancement deals with establishing an administrative limit and it is not clear to the staff why such a limit is to be established only for those transients used in the environmentally-assisted fatigue evaluations. Also, establishing a limit solely on the 60-year projected cycles, without referencing the CUF value, may not ensure that the acceptance criterion for CUF will be met through the period of extended operation. In particular, if the environmental or transient strain rate conditions are adversely exceeded for some duration, and/or the actual cycles analyzed are less than the design limit cycles.

The staff requests the following information:

1. Clarify if monitoring any transient that was used in an environmentally assisted fatigue evaluation with 60-year projected cycles should be an enhancement to GALL AMP X.M1, which recommends monitoring all transients that are significant contributors to fatigue usage.

2. Justify why establishing the administrative limit only for those transients used in an environmentally assisted fatigue evaluation is adequate to ensure that the acceptance criterion for CUF will be met through the period of extended operation.

3. Justify why establishing the administrative limit solely on the basis of 60-year projected cycles, without reference to the actual analyzed cycles and the CUF value/estimation that may be affected by possible adverse environmental or strain rate conditions, is sufficient to ensure that the acceptance criterion for CUF will be met through the period of extended operation, consistent with the GALL AMP X.M1.

RAI B.2.16-6

LRA Section B.2.16, "Fatigue Monitoring Program," discusses the operating experience associated with fatigue issues focusing, primarily, on industry initiatives and NRC/vendor information that caused the applicant to assess thermal stratification of the pressurizer surge line which resulted in changes to the fatigue analyses of record and to the cycles being counted under its Fatigue Monitoring Program.

During its audit, the staff reviewed the applicant's operating experience and condition reports and noted that in-service fatigue issues had occurred, such as thermal sleeve cracking and welded plug cracking, that were identified by the existing program. The staff noted that LRA Section B.2.16 did not discuss these in-service fatigue issues, the corrective actions taken and how the existing Fatigue Monitoring Program was modified based on the operating experience.

Justify the effectiveness of the existing Fatigue Monitoring Program with examples and sufficient details from plant-specific experience to demonstrate that timely identification of observed fatigue degradation was achieved, and the corrective actions taken to prevent the recurrence of such failures. Discuss any improvements that were incorporated into the Fatigue Monitoring Program based on this plant-specific experience.

RAI B2.16-7

LRA Sections 4.7.1.1, 4.7.4, 4.7.5.1, and 4.7.5.2 credit the applicant's Fatigue Monitoring Program to manage the aging effects associated with the TLAA. In accordance with 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended functions will be adequately managed for the period of extended operation.

LRA Section B.2.16 states:

> The Fatigue Monitoring Program is an existing program that, with enhancement, will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801, Section X.M1, "Metal Fatigue of Reactor Coolant Pressure Boundary."

The applicant includes the aforementioned enhancement in Commitment No. 9, which is associated with the applicant's cycle counting activities, action limits and corrective actions for those components that are included in the applicant's cumulative usage factor (CUF) calculations. The applicant's UFSAR Supplement for the Fatigue Monitoring Program in LRA Section A.1.16 is also associated with the program's cycle counting activities for design basis CUFs and the environmentally-adjusted CUFs.

The staff noted that the applicant's Fatigue Monitoring Program is based on GALL AMP X.M1, which is limited to the use of cycle counting for CUF analyses (e.g. ASME Code Section III CUF analyses and environmentally-assisted CUF analyses). The use of cycle counting to manage flaw growth of either a postulated or existing macro flaw is not covered by GALL AMP X.M1.

The applicant has expanded its Fatigue Monitoring Program to use cycle counting for fatigue flaw growth analyses (described in LRA Sections 4.7.1, 4.7.4, 4.7.5.1, and 4.7.5.2) without the inclusion of enhancements to the applicable program elements (e.g. "scope of program," "parameters monitored or inspected," "monitoring and trending," "acceptance criteria," or "corrective action"). These enhancements should provide justification for all cycle counting design transients that were assumed in these fatigue flaw growth or cycle dependent flaw tolerance analyses.

It is not clear to the staff if the applicant's basis for cycle counting design transients has been captured in the applicable documents (e.g. Technical Specification, UFSAR, and cycle counting procedure) describing the management of fatigue flaw growth during the period of extended operation. In addition, LRA Section A.1.16 does not currently discuss the use of cycle counting for these fatigue flaw growth or cycle dependent flaw tolerance analyses in LRA Sections 4.7.1, 4.7.4, 4.7.5.1, and 4.7.5.2.

The staff requests the following information:

1. Clarify all fatigue flaw growth, cycle-dependent flaw tolerance or fracture mechanics TLAAs that are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) and credit the Fatigue Monitoring Program. For each identified analysis: (a) provide the reference in the CLB that forms the basis for the analysis; and (b) identify the transients that were assumed and, for each transient, provide the assumed cumulative number of cycles.

2. Justify the use of cycle counting, as described in the Fatigue Monitoring Program, for the analyses identified in request (1) and dispositioning the associated TLAA in accordance with 10 CFR 54.21(c)(1)(iii) without: (a) an update to the applicable documents (e.g. Technical Specification, UFSAR, and cycle counting procedure), and (b) the inclusion of enhancements to the applicable program elements (e.g. "scope of program," "parameters monitored or inspected," "monitoring and trending," "acceptance criteria," or "corrective action").

   If enhancements and applicable commitments in LRA Appendix A are necessary, provide the following for each analysis: (a) justification for the use of cycle counting activities, (b) definition of the transients that need to be monitored when implementing cycle counting of design transients that were assumed, (c) action limits associated with the assumed transients, and (d) corrective action(s) that will be taken if an action limit is reached.

(c) Justify why LRA Section A.1.16 does not include a summary description on the use of the Fatigue Monitoring Program's cycle counting activities for the design transients that were assumed in the fatigue flaw growth or cycle dependent flaw tolerance analyses described in the LRA Section 4.

RAI B.2.18-1

GALL AMP XI.M27, "Fire Water System," states in the "scope of program" element that the Fire Water System Program manages loss of material due to corrosion, MIC or biofouling, and includes flow testing, visual inspections, and non-intrusive examinations to detect these aging effects. LRA Section B.2.18 states that the applicant's Fire Water Program will manage loss of material as well as cracking of susceptible materials. The applicant's program basis documents state that cracking due to stress corrosion cracking of copper alloy (greater than 15 percent zinc) will be managed by the same testing and inspection activities that identify and manage the loss of material. The staff noted that flow tests and visual inspections are not industry-accepted methods to detect cracking.

It is unclear to the staff what technique the applicant plans to use in its Fire Water System Program that will adequately manage cracking of susceptible copper alloy (greater than 15 percent zinc) components.

In light of the fact that flow tests and visual inspections are not industry accepted methods to detect cracking, provide additional information regarding the technique to be used to detect cracking of copper alloy (greater than 15 percent zinc) fire water system components.

RAI B.2.24-1

GALL AMP XI.M1 states that the components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the volumetric and surface examination requirements, but not exempt from visual exam requirements of ASME Code Section XI, Subsections IWB-2500, IWC-2500, and IWD-2500.

During its audit, the staff noted that the applicant's program basis document for the Inservice Inspection Program states that the components described in ASME Section XI Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500 per the Third Ten-Year Inservice Inspection Program Plan.

Based on the applicant's program basis document, the Third Ten-Year Inservice Inspection Program exempts visual inspection for components described in ASME Section XI Subsections IWB-1220, IWC-1220, and IWD-1220, which is not consistent with the recommendations in the GALL Report. The staff also noted that the applicant did not provide an "exception" to GALL AMP XI.M1, with sufficient justification, for exempting visual inspections of the components described above.

Clarify if the components described in ASME Section XI Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the visual inspections requirements of Subsections IWB-2500, IWC-2500, and IWD-2500. Provide sufficient justification for this "exception" to the recommendations of GALL AMP XI.M1 which requires visual examinations of the components described in ASME Section XI Subsections IWB-1220, IWC-1220, and IWD-1220. If these components are not exempt from GALL AMP XI.M1, provide sufficient information demonstrating that visual inspections are conducted for these components.

RAI B.2.31-1

GALL AMP XI.M20, "Open-Cycle Cooling Water System," states that this program addresses the aging effects of loss of material, fouling due to micro- or macro-organisms, and various corrosion mechanisms generally found in the open cycle cooling water system. The GALL Report AMP does not address cracking, and although it was not identified as an exception or enhancement; the LRA states that copper alloy (with greater than 15 percent zinc) will be managed for cracking by the Open-Cycle Cooling Water Program. The LRA also states that the program consists of inspections, surveillances, and testing to detect and evaluate aging effects including cracking, and it is combined with chemical treatments and cleaning activities to minimize aging effects including cracking.

The LRA does not describe the inspection, surveillance, or testing method(s) that will be used to detect and evaluate cracking of the copper alloy (with greater than 15 percent zinc) components exposed to open cycle cooling water. In addition, the LRA does not describe the chemical treatments and cleaning activities that will be used to minimize cracking.

The staff requests the following information:

1) Describe the aging management activities in the Open-Cycle Cooling Water Program that will be used to manage cracking of the copper alloy (with greater than 15 percent zinc) components with greater than 15 percent zinc that are exposed to raw water.

2) If the Open-Cycle Cooling Water Program will remain, the program used to manage cracking of copper alloy (with greater than 15 percent zinc) components, then the LRA should be updated to reflect this as an exception to GALL AMP XI.M20.

RAI B.2.33-1

The GALL AMP XI.M2, "Water Chemistry," states in program element 3, "Parameters Monitored/Inspected," that the applicant should utilize the EPRI water chemistry guidelines to determine the concentrations of corrosive impurities monitored to mitigate loss of material, cracking, and reduction in heat transfer. The GALL AMP XI.M2 Program Description references EPRI 1016555 (PWR Secondary Water Chemistry Guidelines – Revision 7). The applicant's basis document states that its pressure water reactor (PWR) Water Chemistry Program is consistent with the Revision 5 of the EPRI guidelines concerning secondary water chemistry. The applicant's basis documents further states that the program is periodically updated to the latest guidelines. The applicant's 2009 self-assessment of its secondary water chemistry guidelines states that program documents should be revised based on the EPRI Revision 7 document on PWR Secondary Water Chemistry.

It appears to the staff that the applicant's Water Chemistry Program implementing procedures and basis documents have not been updated to reflect the updated EPRI PWR Secondary Water Chemistry Guidelines, Revision 7, despite the information in the Program Description for GALL AMP XI.M2 and despite the recommendations from the applicant's own 2009 self-assessment of its secondary water chemistry guidelines. Clarify if and/or when the Water Chemistry Program implementing procedures and basis documents will be updated to reflect the requirements of EPRI's PWR Secondary Water Chemistry Guidelines, Revision 7. If these procedures and documents will not be updated, provide a justification supporting the continued use of Revision 5 of EPRI's PWR Secondary Water Chemistry Guidelines as it relates to determining the concentrations of corrosive impurities monitored to mitigate loss of material, cracking, and reduction in heat transfer.

RAI B.2.36-1

Because selective leaching is a slow acting corrosion process, the "detection of aging effects" program element of GALL AMP XI.M33, "Selective Leaching," recommends the inspection be conducted within the last five years prior to the period of extended operation. LRA Section B.2.36 states that selective leaching inspection activities will be conducted "before the beginning of the period of extended operation."

The description of the timing of the performance of selective leaching inspections in LRA Section B.2.36 does not ensure these inspections will be conducted within the last five years prior to the period of extended operation, as suggested GALL AMP XI.M33.

The staff requests the following information:

1. In light of the fact that selective leaching is a slow acting process, clarify the planned timing of the conduct of selective leaching inspections relative to the beginning of the period of extended operation.

2. Revise LRA Appendix A, "Updated Safety Analysis Report Supplement," Section A.1.36, "Selective Leaching Inspection," to reflect the fact that inspections required by this program will be conducted within the last five years prior to the period of extended operation.

RAI B.2.36-2

The "detection of aging effects" program element of GALL AMP XI.M33, "Selective Leaching," recommends that the inspection includes a representative sample (e.g., 20 percent of the population with a maximum sample of 25) of the system population with focus on the components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin. Otherwise, a technical justification of the methodology and sample size used for selecting components should be included as part of the program's documentation. LRA Section B.2.36 states that the selective leaching inspection activities include determination of the sample size based on an assessment of materials of fabrication, environment/conditions, time in service, and operating experience, as well as identification of the inspection locations in the susceptible system or component.

It is not clear to the staff whether the extent and scope of the selective leaching inspection activities are consistent with the GALL AMP XI.M33 recommendation.

The staff requests the following information:

1. Revise LRA Section B.2.36 to indicate that a representative sample (e.g., 20 percent of the population with a maximum sample of 25) of the system population will be selected for inspection to demonstrate the absence of selective leaching.

2. Describe the methodology used to ensure the representative sample focuses on the components most susceptible to aging due to time in service, severity of operating conditions, and lowest design margin.

3. As an alternative to Requests 1 and 2 above, update LRA Section B.2.36 to include a technical justification for the methodology and sample size used for selecting components.

RAI B.2.36-3

SRP Section A.1.2.3.10.3 states that the applicant should commit to a review of future plant-specific and industry operating experience for new programs to confirm their effectiveness. LRA Section B.2.36 describes the Selective Leaching Inspection Program as a new one-time inspection that will be consistent with the 10 elements of an effective aging management program as described in NUREG-1801. LRA Section B.2.36 also states that a review of Davis-Besse operating experience did not identify any instances of loss of material due to selective leaching, graphitization, or dezincification for any in-scope components.

The "operating experience" program element of LRA Section B.2.36 does not include substantive operating experience examples confirming the effectiveness of the new Selective Leaching Inspection Program nor does the applicant otherwise commit to a review of future plant-specific and industry operating experience to confirm the program's effectiveness.

Revise LRA Table A-1, "Davis-Besse License Renewal Commitments," Item 18, to include the performance of a review of future plant-specific and industry operating experience to confirm the effectiveness of the new Selective Leaching Inspection Program.

RAI B.2.37-1

GALL AMP XI.M35 states that the program is applicable to systems that have not experienced cracking of ASME Code Class 1 small-bore piping. This program can also be used for systems that experienced cracking but have implemented design changes to effectively mitigate cracking. For systems that have experienced cracking and operating experience indicate that design changes have not been implemented to effectively mitigate cracking, periodic inspection is proposed, as managed by a plant-specific AMP.

The applicant stated in LRA Section B.2.37, "Small Bore Class 1 Piping Inspection Program," that two instances of small bore piping cracking related to stress corrosion cracking have been identified at Davis-Besse. The staff noted that, since the applicant has plant-specific operating experience for cracking in its small-bore piping at its site, a one-time inspection program may not be applicable.

Based on the plant-specific operating experience, justify the use of a one-time inspection program to manage cracking in ASME Code Class 1 small-bore piping. Otherwise, in lieu of a justification, provide a plant-specific program to perform periodic inspections of ASME Code Class 1 small-bore piping.

RAI B.2.37-2

LRA Section B.2.37, "Small Bore Class 1 Piping Inspection Program," states that the program will be implemented "prior to period of extended operation." In addition, Commitment No. 19 in LRA Table A-1 states that this program will be implemented on April 22, 2017. However, GALL AMP XI.M35 states that the one-time inspection should be completed within the six-year period prior to the period of extended operation. The specified six-year time frame is to ensure timely completion of the inspections and to allow a more realistic assessment of material conditions prior to entering the period of extended operation.

Based on LRA Section B.2.37, it is not clear to the staff when the applicant's Small Bore Class 1 Piping Inspection Program will be implemented at this site, and if this implementation of the program is consistent with the recommendations of GALL AMP XI.M35 which requires the completion of the one-time inspections within the six-year period prior to the period of extended operation.

Clarify the implementation schedule of the one-time inspections to be performed by the Small Bore Class 1 Piping Inspection Program. If the implementation schedule is not consistent with the recommendations in GALL AMP XI.M35, justify why the one-time inspections do not need to be completed within the six-year period prior to the period of extended operation. Amend the LRA and Commitment No.19, as needed, in response to this RAI.

RAI B.2.37-3

GALL AMP XI.M35 provides specific guidance regarding small bore piping inspection sampling. LRA Section B.2.37, "Small Bore Class 1 Piping Inspection Program," states that the program will perform volumetric examinations of a representative sample of small bore piping locations that are susceptible to cracking.

The staff noted that the applicant has not provided specific information regarding the small bore piping weld population, or the inspection sampling size. This information is needed to evaluate consistency of the applicant's program with the recommendations of GALL AMP XI.M35.

Clarify the total population of Class 1 small bore butt welds and socket welds such that the sample size is described as a percentage of welds for each type. In addition, justify the adequacy of the sampling methodology in the Small Bore Class 1 Piping Inspection Program if the percentage is less than the sampling guidelines, as described in GALL AMP XI.M35.

Barry S. Allen
Vice President, Davis-Besse Nuclear
Power Station
FirstEnergy Nuclear Operating Company
5501 North State Route 2
Oak Harbor, OH 43449

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 2 (TAC NO. ME4640)

Dear Mr. Allen:

By letter dated August 27, 2010, FirstEnergy Nuclear Operating Company, submitted an application pursuant to 10 *Code of Federal Regulation* Part 54 for renewal of Operating License NPF-3 for the Davis-Besse Nuclear Power Station. The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the Enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Cliff Custer, of your staff, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2277 or by e-mail at brian.harris2@nrc.gov.

Sincerely,

Brian K. Harris, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-346

Enclosure:
As stated

cc w/encl: Listserv

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OFFICE:	LA:DLR	PM:RPB1:DLR	BC:RPB1:DLR	PM:RPB1:DLR
NAME:	SFigueroa	BHarris	BPham	BHarris
DATE:	4/18/11	4/18/11	4/20/11	4/20/11

Letter to B. Allen from B. Harris Dated April 20, 2011

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE DAVIS-BESSE NUCLEAR POWER STATION – BATCH 2 (TAC NO. ME4640)

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B. Harris
P. Cooper
B. Harris (OGC)
M. Mahoney