September 23, 2003

APPLICANT: Omaha Public Power District

FACILITY: Fort Calhoun Station, Unit 1

SUBJECT: SUMMARY OF MEETING WITH OMAHA PUBLIC POWER DISTRICT (OPPD) TO DISCUSS DRAFT RESPONSES TO REQUESTS FOR ADDITIONAL INFORMATION (RAIs) FOR THE RENEWAL OF THE OPERATING LICENSE FOR FORT CALHOUN STATION, UNIT 1 (FCS)

On December 3 and 4, 2002, the NRC staff (the staff) and representatives from OPPD held meetings to discuss draft responses to RAIs resulting from the staff's review of license renewal application (LRA) Sections 2.3.3.19 (Primary Sampling), 2.3.3.20 (Radiation Monitoring - Mechanical), 3.3 (Auxiliary Systems), 3.4 (Steam and Power Conversion Systems), 3.5 (Structures), 4.1 (Identification of Time Limited Aging Analyses), 4.3 (Metal Fatigue), 4.5 (Concrete Containment Tendon Pre-Stress), 4.6 (Containment Liner Plate and Penetration Sleeve), B.1.3 (Containment Inservice Inspection Program), B.1.4 (Containment Leak Rate Program), B.1.7 (Reactor Vessel Integrity Program), B.2.3 (Diesel Fuel Monitoring and Storage Program), B.2.4 (Fatigue Monitoring Program), and B.2.5 (Fire Protection Program). Meeting participants are enclosed. OPPD has had an opportunity to review and comment on this summary.

2.3.3.19 Primary Sampling

RAI 2.3.3.19-1 Drawing 11406-M-12, Sheet 1 shows Sample Heat Exchangers SL-3, SL-8A, SL-8B and Sample Cooler SL-51 as being within the scope of license renewal for the primary sampling system. The intended functions of these components are heat transfer and pressure boundary. In all four cases, the primary sampling system inlet and outlet piping is not within the scope of license renewal. The failure of this piping could compromise the pressure boundary function of the heat exchangers and sample chiller. Provide justification for not including the inlet and outlet piping within the scope of license renewal.

Response:

Table 2.3.3.19-1 of the application incorrectly identifies an intended function of Heat Transfer for these heat exchangers. They provide only a pressure boundary function for the component cooling water system (CCW). The license renewal boundary flags on the referenced drawings are, therefore, correct.

Meeting Discussion:

The staff noted that the flags on the drawing show that the sample heat exchanger and chiller are within the scope of the primary sampling

system, but should be within the scope of the CCW system. The applicant clarified that they scoped the heat exchanger and chiller in the primary sampling system to be consistent with the Generic Aging Lessons Learned (GALL). The staff requested that this explanation should be clarified in the RAI response.

2.3.3.20 Radiation Monitoring-Mechanical

RAI 2.3.3.20-1 Drawing 11405-M-1, Sheet 2 is the only drawing listed as showing the license renewal boundaries for this system. The drawing appears to show only three equipment cabinets as being within the scope of license renewal. Table 2.3.3.20-1 lists five component types subject to aging management review. Clarify where the components within the scope of license renewal for the Radiation Monitoring-Mechanical system are shown and/or listed? Provide an inclusive drawing or drawings showing the Radiation Monitoring-Mechanical system license renewal boundaries. This information is necessary in order for the staff to have reasonable assurance that all the structures, systems, and components (SSCs) have been correctly identified as being within scope and subject to an AMR in accordance with 10 CFR 54.

Response:

There were three (3) LR Boundary Drawings for the Radiation Monitoring – Mechanical System that were not sent with the application because they are proprietary to the vendor that supplied the radiation monitors. The vendor does not allow reproduction of these drawings for distribution to parties outside of the organization of the purchaser of the equipment. For this reason, these drawings were not being docketed with the LRA. There is a hard copy of each drawing included in EA-FC-00-115, *Radiation Monitoring – Mechanical Scoping, Screening, and Aging Management Review for License Renewal*, that will be available to the NRC Inspection Team or these drawings can be transmitted to the NRC as proprietary information.

Meeting Discussion:

The applicant brought the proprietary drawings for staff review. The staff reviewed the drawings to ensure that the appropriate components were included within scope.

The staff asked that the RAI response be revised to clarify whether the housings for the gas samplers and detectors, or the instruments themselves, serve as the pressure boundary, and clarify where the pressure boundary components are identified in LRA Section 2.

3.3 Auxiliary Systems

RAI 3.3-2 Numerous tables included in the application list the component material and the environment to which the component is exposed. However, the applicant did not provide a description of these environments in the LRA. It should be noted that aging effect depends on the component material as well as the plant specific environment characteristic. For example, aging effect of component exposed to air environment is dependent, in part, on the type of air, the temperature, the oxygen content, and the water content (humidity), etc. The applicant is requested to provide a description of these environments included in the LRA.

Response:

In the FCS LRA, the environments used in the Section 3 aging management review (AMR) tables match those that are used in the GALL Report. In all of the 3.X-1 tables, each line item corresponds exactly with a GALL Report line item. The same is true for the 3.X-3 tables. Where there is a differentiation relative to the temperature, oxygen content, use of a corrosion inhibitor, etc. within an environment specified in the GALL Report (e.g., high temperature borated treated water, deoxygenated treated water >200°F, oxygenated treated water <200°F, etc.), the same differentiation has been used in the FCS LRA.

Meeting Discussion:

The applicant clarified that the aging effects associated with the worst-case environmental conditions are assumed in developing the aging management program. For example, if a component is exposed to an air environment, the worst-case air environment (humid air), and the associated aging effects, was assumed when developing the aging management program. The applicant agreed to revise the RAI response to provide a table of environments associated with license renewal, and to clarify the environmental methodology discussed above. The staff requested that the applicant provide a draft of the revision for staff review.

The staff and applicant agreed that it would be worthwhile to include an environment table in the GALL report.

RAI 3.3.1-1 Numerous ventilation systems discussed in Section 2.3 of LRA included elastomer components in the system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. In Table 3.3-1, Row Number 3.3.1.02 of the LRA, the applicant identified the aging effects of hardening, cracks, and loss of strength due to elastomer degradation, and loss of material due to wear for these elastomer components. To manage these aging effects, the applicant relied on its General Corrosion of External Surface Program, described in LRA Section B.3.3. The description for this program identifies loss of material and cracking as plausible

aging effects. The applicant stated that these aging effects can be detected by visual observation and inspection of external surfaces, which are performed at intervals based on previous inspections and industry experience. The applicant is requested to clarify the discrepancy between Table 3.3-1, Row Number 3.3.1.02 and Section B.3.3 regarding the aging effects of concern. Specifically, the applicant is requested to clarify whether hardening and loss of strength are considered in the general corrosion of external surfaces program, and how these aging effects will be detected and managed using this program. In addition, the applicant is requested to provide the frequency of the subject inspection described in Section B.3.3 for the applicable elastomer components including a discussion of the operating history to demonstrate that the applicable aging degradations will be detected prior the loss of their intended function.

Response:

The aging effects of hardening and loss of strength for elastomers are not included in the General Corrosion of External Surfaces Program (B.3.3). Enhancements will be made to add these aging effects requiring management (AERMs) to preventive maintenance tasks under the Periodic Surveillance and Preventive Maintenance Program (PS/PMP)(B.2.7) to specifically inspect elastomer expansion joints, seals, and vibration isolators within the scope of license renewal for hardening and loss of strength. The PS/PMP has been added to Discussion Item 2 in AMR Item 3.3.1.02.

Relative to monitoring for cracks and loss of material, procedural guidance requires system engineers to perform walkdowns of their assigned systems on a quarterly basis, as a minimum. Operator walkdowns usually occur multiple times per 12-hour shift. No instances of the loss of ventilation system intended function due to failure of elastomers have been found in existing corrective action documentation.

Meeting Discussion:

The applicant agreed to revise the RAI response to include the frequency of inspection in AMP B.2.7 to identify hardening and loss of strength in elastomer expansion joints, seals, and vibration isolators. In addition, the response will be revised to indicate that visual inspection for cracks and loss of material also includes the operator to feel for these aging effects during walkdowns. The preventive maintenance tasks and procedural guidance referred to in the applicant's response will be included as part of the staff's AMR inspection.

RAI 3.3.1-2 Numerous components included in LRA Tables 2.3.3.7-1 and 2.3.3.8-1 referred to Table 3.3-2, Row Number 3.3.2.23, for the aging management review results. These components are made of carbon steel and are exposed to the internal environment of instrument air. The LRA states that there are no aging effects that required management for this material/environment combination. Similarly, in Table 3.3.1, Row Number 3.3.1.18, the applicant stated that the components in the instrument air system at Fort Calhoun Station (FCS) are exposed to dry air

and the environment (wet air/gas) identified in NUREG-1801 is not applicable to FCS. It should be noted that in the instrument air system, components that are located upstream of the air dryers are generally exposed to a wet air/gas environment and therefore, may be subject to loss of material due to general and pitting corrosion. In addition, it is reasonable to assume that components downstream of the dryers are exposed to dry air/gas environment. However, this may not be supported by some operating experience. For an example, NRC IN 87-28, “Air Systems Problems at U.S. Light Water Reactors,” provides the following: “A loss of decay heat removal and significant primary system heat up at Palisades in 1978 and 1981 were caused by water in the air system.” This experience implies that the air/gas system downstream of the dryer may not be dry. On the basis of this industry experience, the applicant is requested to discuss its plant specific operating experience related to components that are exposed to an instrument air environment, and to provide a technical basis for not identifying loss of material as an aging effect for these components.

Response:

The Instrument Air System boundary does not include components upstream of the dryers. Those components are part of the Compressed Air System. The industry operating experience is varied because of the differences in system design and air dryer types in use. For stations with refrigerant dryers, the dewpoint of the air system is typically in the range of +30°F to +40°F. While this does prevent water accumulation in the system, it still provides sufficient moisture to allow corrosion. Also, for systems with a single air dryer, wet air can be pumped into the system in the event of a failure to the air dryer. Additionally, if the system dewpoint is not monitored, that condition can go undetected for a significant length of time, which may cause corrosion to occur.

The Fort Calhoun operating experience has not shown that a wet environment exists downstream of the air dryers. The reasons for that are threefold. First, Fort Calhoun has always used desiccant type air dryers which, reduce the dewpoint of the instrument air to <-40°F. This low level of moisture has been shown to preclude the corrosion mechanisms responsible for loss of material that occur in wet systems. Second, Fort Calhoun had redundant air dryers installed. Lastly, the dewpoint of the instrument air is monitored with a sensor which alarms in the control room in the event the dewpoint exceeds -25°F.

Meeting Discussion:

The staff was concerned that the response may imply that dewpoint temperatures greater than -40°F but less than -25°F may result in a wet environment in the instrument air system that could result in loss of material. The applicant clarified that any environment below the -25°F alarm setpoint will not result in corrosion in the system. The RAI response will be revised to clarify this.

RAI 3.3.1-8 In LRA Table 2.3.3.13-1, the applicant identified loss of material as a plausible aging effect for ducts and fittings. The staff noted that for ducts in other ventilation systems, the applicant has also identified aging effects related to the elastomer degradation. In order for the staff to understand whether aging effects are applicable to elastomers in the ducts for the ventilating air system, the staff requests the applicant to clarify whether there are elastomer components in the ventilating air system and to provide a technical basis for not considering aging degradation of the elastomer component, if any.

Response:

There are no elastomers in the Ventilating Air System; therefore, there are no aging effects requiring management.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.3.2-4 In LRA Table 2.3.3.10-1, the applicant identified two intended functions, heat transfer and pressure boundary, for the heat exchanger, and referred to LRA Tables 3.3-1, 3.3-2, and 3.3-3, rows 3.3.1.05, 3.3.2.10, 3.3.2.39, and 3.3.3.09 for the aging management review results for the heat exchanger. In LRA Table 3.3-2, row 3.3.2.39, the applicant identified loss of material as the applicable aging effect and credited the Chemistry Program and Cooling Water Corrosion Program for managing the aging effect. However, the staff notes that fouling is another aging effect that will result in a loss of the intended function of heat transfer. The applicant is requested to provide a technical basis for not identifying fouling as an applicable aging effect for the heat exchanger that has an intended function of heat transfer, or provide a program to manage fouling in the heat exchanger.

Response:

Fouling has not been identified as an AERM because the cooling medium for these coolers is CCW. Consistent with the GALL Report, fouling is only applicable as an AERM for heat exchangers when an Open Cycle Cooling Water System is used. FCS operating experience has shown that fouling of cooling water coils does not occur.

Meeting Discussion:

The staff expressed concern that, though biofouling may not be a concern, fouling due to corrosion is a concern in maintaining the heat transfer function. The applicant noted that the FCS operating experience has never detected microbiologically-influenced corrosion, but despite no evidence of fouling, it will monitor for fouling as part of the cooling water corrosion program (LRA Section B.2.2). The staff requested that this be clarified in the RAI response.

Also, with regard to the exception noted in LRA Section B.2.2, the applicant noted that the heat transfer is also maintained as part of the program, and that the exception was an attempt to clarify that fluid flow is not specifically monitored in the program. However, the staff and applicant agreed that fluid flow is a parameter needed to assess the maintenance of the heat transfer function, as provided in EPRI TR-107396. The applicant also explained that the exception also attempted to clarify that the 18-month and 5-year frequencies for performance testing are not included in EPRI TR-107396. The staff noted GALL XI.M21 does identify these frequencies as part of EPRI TR-107396. The staff and applicant agreed that the exception noted in LRA Section B.2.2 is confusing, and the applicant will revise the RAI response to clarify the intent of the exception or delete it, and clarify the performance and functional test frequencies.

RAI 3.3.2-5 In LRA Table 2.3.3.12-1, the applicant identified two intended functions, heat transfer and pressure boundary for the heat exchanger, and referred to Tables 3.3-1 and 3.3-2, rows 3.3.1.05, 3.3.2.29, 3.3.2.39, and 3.3.2.40, for the aging management review results for the heat exchanger. In LRA Table 3.3-2, rows 3.3.2.29 and 3.3.2.39, the applicant identified loss of material as the applicable aging effect and credited Chemistry Program and Cooling Water Corrosion Program for managing the aging effect. However, the staff notes that fouling is another aging effect that will result in a loss of the intended function of heat transfer. The applicant is requested to provide a technical basis for not identifying fouling as an applicable aging effect for this heat exchanger, or provide a program to manage fouling in the heat exchanger.

Response:

See response to 3.3.2-4.

Meeting Discussion:

The staff and applicant agreed that the revision to the applicant’s response the RAI 3.3.2-4 will adequately address this RAI.

RAI 3.3.3-1 For several components in the auxiliary systems, the applicant referred to Table 3.3-3, Row Number 3.3.3.09 for the aging management review results for these components. In that table, the applicant identified “ambient air” as the environment and credited the Boric Acid Corrosion Prevention Program for managing the aging effect. The applicant also referred to Row Number 3.3.1.13 of Table 3.3-1 as the applicable NUREG-1801 aging management review results. The staff noted that the referred NUREG-1801 item addresses the aging effect of a component group in air exposed to leaking and dripping borated treated water. The applicant is requested to clarify that “boric water leaks” rather than “ambient air” is the environment characteristic of concern.

Response:

The normal environment for these components is ambient air. It is possible, although improbable, that there can be leakage of water from borated water systems onto exposed carbon steel surfaces. For this reason, that possibility is covered by providing the link through AMR Item 3.3.3.09 to AMR Item 3.3.1.13, which corresponds to GALL Report Item VII.I.1-a.

Meeting Discussion:

The staff had no further issues with this response, but requested that the response be revised to clarify that LRA Table item 3.3.3.09 is being revised to match 3.3.1.13 (i.e., air exposed to leaking and dripping borated treated water).

3.4 Steam and Power Conversion Systems

RAI 3.4-1 The staff's review of LRA Section 3.4 found that the aging effects associated with two types of materials jointed together, such as carbon steel jointed with stainless steel, are not discussed. Do any components in the steam and power conversion systems consist of dissimilar metals? Can they be subject to loss of material due to galvanic corrosion? If so, identify these components and describe how the aging effects due to galvanic corrosion are managed during the period of extended operation, or provide justification for why loss of material due to galvanic corrosion is not a plausible aging effect.

Response:

Galvanic corrosion is not identified as an AERM for the systems/components included in the Steam and Power Conversion System section (Section VIII) of the GALL Report.

However, OPPD has identified components in the Feedwater System, the Auxiliary Feedwater System, and the Main Steam System that are potentially subject to galvanic corrosion. These components are managed for aging in the same manner, using the same AMPs, as all components subject to a loss of material. Details relative to these components will be available on-site for NRC inspection.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4-2 The staff cannot discern internal from external environments in the LRA. Therefore, the staff requests the applicant to confirm whether raw water is not an internal or external environment that steam and power conversion system components are exposed to. If any components in the steam and power conversion systems are exposed to raw water, identify the system, components,

aging effects, and aging management programs credited with managing the aging effects.

Response:

Raw water is not an environment for the Steam and Power Conversion Systems.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-1 In LRA Table 3.4-1, row number 3.4.1.12, it states that the external surfaces of buried condensate storage tank and AFW piping identified in the GALL report is not applicable to Fort Calhoun. The staff needs to understand the basis for the applicant's conclusion that this GALL item is not applicable to FCS. Does this mean that there are no buried tanks or piping in the steam and power conversion systems at Fort Calhoun, or are there no plausible aging effects for these components? Please clarify the basis for the conclusion.

Response:

There are no buried Steam and Power Conversion System components at FCS.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-2 Industry operating experience has identified cracking from mechanical vibration as a potential aging effect for the piping system components in the steam and power conversion systems. Given this experience, please explain why mechanical vibration is not identified as an applicable aging effect for components in the steam and power conversion systems.

Response:

Cracking is already identified and managed as an AERM for applicable components in the Steam and Power Conversion Systems. Mechanical vibration is a mechanism that can result in cracking. Additionally, mechanical vibration is a mechanism that is not an aging issue. It is a design issue. When it occurs, it typically involves the misapplication of mechanical components, the improper sizing of components or piping, the improper location of piping fittings that change flow direction, or some combination of these. As such, cases of mechanical vibration problems, especially where damage has occurred, are eliminated via design changes.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-3 LRA Table 3.4-1, row 3.4.1.08, discusses aging management of closure bolting, and credits the bolting integrity program (LRA Section B.1.1) for managing loss of material and crack initiation, with one exception. LRA Section B.1.1 states that the bolting integrity program will be consistent with GALL program XI.M3, “Reactor Head Closure Studs” and XI.M18, “Bolting Integrity,” with the exception that SCC has not been identified as a creditable aging effect for high-strength carbon steel bolting in plant indoor air. The reviewer requests the applicant to discuss the basis for its conclusion that SCC is not a creditable aging effect for bolting.

Response:

See response to RAI 3.2.1-2.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-4 It is stated in LRA Table 3.4-1, Row number 3.4.1.03, that the environment identified in NUREG-1801 is not applicable to FCS, since the AFW piping at FCS is not exposed to untreated water from a backup water supply. It appears that AFW piping from the emergency feedwater storage tank (EFWST) is exposed to ground water, soil and/or outdoor environments and would fall in the category identified in the NUREG-1801. Since there is no reference to the buried piping program for the AFW piping in LRA Section 2.3.4.2-1 for the AFW piping, provide clarification as to how the aging effects in this portion of the AFW piping will be managed.

Response:

The EFWST is not outside. It is located inside the Auxiliary Building; therefore, there is no buried AFW piping. Refer to boundary drawing 11405-M-254, Sh2. This drawing shows that the tank is located in the Auxiliary Building.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-5 It is stated in LRA Table 3.4-1, Row number 3.4.1.05, that the group includes carbon and low alloy steel in ambient air. The statement implies that other materials and environments are covered in this group. Please identify those materials and environments. Also, for the ambient air environment, provide the range of humidity and moisture content.

Response:

Per telecon with the NRC, no response is required for this RAI. A discussion will be provided in the telecon summary to address this issue.

Meeting Discussion:

The staff clarified that the summary of the telephone conferences between the applicant and the staff on October 28 and October 31, 2002, states that the applicant will revise the response to clarify that only carbon and low alloy steel in ambient air are the only materials and environments covered by LRA item 3.4.1.05. The response will also note that humidity (moisture content) is not used as a basis for excluding an aging effect; i.e., any plausible aging effects are managed that may result from exposure of these components to moisture.

RAI 3.4.1-6 LRA Tables 2.3.1.1-1 and 2.3.4.2-1 identify components, intended functions, and aging management review results for the feedwater and the AFW systems, respectively. Item 3.4.1.08 in the AMR results column for bolting in these systems leads to the aging management of loss of material due to general corrosion, crack initiation, and growth due to cyclic loading and/or SCC in closure bolting in LRA Table 3.4-1. The aging effect is stated to be managed by the bolting integrity program. However, the scope of this program as discussed in LRA Section B.1.1, does not include LRA Tables 3.4-1, 3.4-2 or 3.4-3. Provide clarification for this discrepancy.

Response:

Refer to the response to RAI 3.1-2.

Specific to the Bolting Integrity Program, there are no components in Tables 3.4.2 or 3.4.3 that reference this program.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-7 LRA Tables 2.3.4.1-1 (Feedwater), 2.3.4.2-1 (Auxiliary Feedwater), and 2.3.4.3-1 (Main steam and Turbine steam extractions) identify item 3.4.1.13 for AMR results of bolting. In LRA Table 3.4-1, row number 3.4.1.13, it is stated that the boric acid corrosion prevention program would manage the aging effect of loss of material due to boric acid corrosion in bolting. However, the steam and power conversion system has not been identified as being within the scope of the boric acid corrosion program as discussed in LRA Section B.2.1. Provide clarification for this discrepancy.

Response:

Refer to the response to RAI 3.1-2.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-8 In LRA Tables 2.3.4.3-1 (Main Steam and Turbine Steam Extraction) and 2.3.4.1-1 (Feedwater), AMR results for pipe/fittings refer to item 3.4.1.06. This link in LRA Table 3.4-1, row 3.4.1.06 identifies flow-accelerated corrosion (FAC) as the AMP for carbon steel piping. However, the scope of the FAC program in LRA Section B.1.5 does not refer to LRA Table 3.4-1, implying that carbon steel piping in main steam and turbine steam extraction and feedwater is not covered by the FAC program. Please clarify this discrepancy. Similarly, link 3.4.3.04 in LRA Table 2.3.4.3-1 identifies the FAC program for managing the aging effects in carbon steel piping/fittings in LRA Table 3.4-3. This indicates that some portions of the piping/fittings in main steam and turbine steam extraction are evaluated in NUREG-1801 and some are not, but are still managed by the FAC program due to similarity of materials and environments. Identify the specific portions of the piping which are evaluated in GALL, and which are not.

Response:

The indication assumed in the next to the last sentence of the RAI is incorrect. The link to 3.4.3.04 is made because that AMR Item adds the filters/strainers that are not specifically addressed by 3.4.1.06 and are part of the system. All of the piping in scope in this system is included in the FAC Program. Refer to the response to RAI 3.1-2.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-9 LRA Table 2.3.4.2-1, which lists components subject to AMR for the auxiliary feedwater system, refers to items 3.4.1.02 and 3.4.1.05 for AMR results for tanks. These links in LRA Table 3.4-1 lead to the chemistry program (B.1.2), one-time inspection program (B.3.5), and general corrosion for external surfaces program (B.3.3). However, the one-time inspection program (B.3.5) does not have LRA Table 3.4-1 within its scope and therefore, excludes tanks in the auxiliary feedwater system. Provide clarification for this discrepancy.

Response:

Refer to the response to RAI 3.1-2.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-10 In LRA Table 2.3.4.2-1, the aging management review results for heat exchangers are identified as 3.4.2.3, 3.4.2.4, 3.4.2.5 and 3.4.2.6. These links in

LRA Table 3.4-2 have no reference to the closed and open cycle cooling system programs as recommended in NUREG 1801, Volume 2, XI.M20, “Open-Cycle Cooling Water System,” and XI.M21, “Closed-Cycle Cooling Water System.” Provide justification to show that the AMP at FCS will provide equivalent aging management for the heat exchangers in the AFW system at FCS.

Response:

These heat exchangers are the lube oil coolers for the steam driven Auxiliary Feedwater Pump. The cooling medium is neither Open nor Closed Cycle Cooling Water. It is auxiliary feedwater off of the discharge of the pump. There is no GALL Report line item equivalent to this component. Given the copper alloy material and the environments of deoxygenated, treated water and lube oil, the programs selected for the aging management of these coolers have been deemed to be appropriate.

Meeting Discussion:

The staff stated that the response should be revised to state that AMP B.2.7, “Periodic Surveillance and Preventive Maintenance Program,” provides aging management of oil systems equivalent to that provided by XI.M21 for cooling water.

RAI 3.4.1-11 With regard to the one-time inspection and the water chemistry programs, GALL recommends inspection of stagnant areas based on severity of condition, time of service, and lowest design margin. Identify these worst-case locations for components in the feedwater, AFW, and main steam and turbine steam extraction systems which utilize these programs.

Response:

Worst-case locations will be evaluated and identified as part of the implementation of the programs prior to the period of extended operation.

Meeting Discussion:

The staff stated that the response should be revised to clarify the parameters (severity of condition, time of service, and lowest design margin) that will be considered when identifying the worst-case locations.

RAI 3.4.1-12 Flow element/orifice housing is not proposed to be managed for FAC in the LRA. In the staff’s experience, these components are sometimes made of carbon steel and therefore may be susceptible to FAC. Please confirm that the steam and power conversion systems do not contain flow elements or orifice housings made of carbon steel. If the steam and power conversion systems contain flow elements and orifice housings made of carbon steel, please provide a justification for why these components are not subject to this aging effect, or

provide a discussion of how this aging effect will be managed for these components.

Response:

As seen from Steam and Power Conversion Section 2 tables, in Table 2.3.4.2-1, the Auxiliary Feedwater System has flow element/orifice housings. From the AMR Item links, however, it is readily seen that these components are fabricated of stainless steel such that FAC does not apply.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.4.1-13 In LRA Table 3.4-1, row number 3.4.1.01 relates to cumulative fatigue damage of piping and fittings, which is managed by a time-limited aging analysis (TLAA), as specified in NUREG 1801, Volume 2, VIII.G-.1-b. for auxiliary feedwater piping. Is this for the entire AFW system, or just a portion of the system? Note that for the MS and feedwater systems, GALL line item VIII.D1.1-b, specifies that only a portion of the piping can utilize a TLAA.

Response:

Refer to Section 4.3.4 of the LRA for discussion relative to the fatigue considerations of Class II and III piping. Basically, due to the design code operational limits for this piping, which includes the AFW system piping in scope, it is being treated as a TLAA and is included within the scope of the Fatigue Monitoring Program.

Meeting Discussion:

The staff stated that the response should be revised to clarify which portions of the AFW system experience thermal fatigue.

RAI 3.4.1-14 The piping and fittings in the feedwater system are subject to wall thinning due to flow accelerated corrosion as indicated in LRA Tables 2.3.4-1 and 3.4-1, Row 3.4.1.06. This aging effect is managed by the FAC program in LRA Appendix B.1.5. However, the scope of this program does not include LRA Table 3.4-1, indicating that piping and fittings in the feedwater system are excluded from the FAC program. Provide clarification for this discrepancy. Also NUREG 1801, Volume 2, VIII D2.3-a and VIII D2.3.2 recommends the FAC program for the feedwater pump (steam turbine and motor driven) suction and discharge lines. Clarify the exclusion of these components from LRA Table 2.3.4-1.

Response:

Refer to the response to RAI 3.1-2. The second part of this RAI does not require a response. Per a telecon with the NRC, the discussion relative to this issue will be addressed in the telecon summary.

Meeting Discussion:

The staff confirmed the summary of the teleconferences held on October 28 and October 31, 2002, respectively, which stated that the applicant need not respond to the part of the RAI that discusses NUREG-1801, Volume 2, items VIII D2.3-a and VIII D2.3.2 because these items refer only to BWRs and therefore are not applicable to FCS.

RAI 3.4.3-1 The FAC Program (LRA Section B.1.5) is intended to be used for filters/strainers (refer to row number 3.4.3.04, Table 3.4-3 of the LRA) because it is stated to have the same material, exposed to the same environment, and is subject to the same aging effects as the components evaluated in NUREG-1801, Volume 2, VIII B1.1-C, which are piping/fitting elbows and valve bodies. The FAC program is an analytical, inspection, and verification program in which the component geometry and hydrodynamic conditions play an important role in the analysis. Since the geometry and hydrodynamic conditions of filters and strainers are substantially different from piping/fittings and valve bodies, explain how the predictive methodology of the FAC program will be applied to filters and strainers.

Response:

Since these strainers are in-line items in the main steam piping that is in scope and since they are routinely inspected, evidence of FAC will be apparent if it is occurring.

Meeting Discussion:

The staff stated that it would like the response revised to add a discussion that the filter/strainers provide gross filtration only.

3.5 <u>Structures</u>

RAI 3.5-1 Each row entry in LRA Table 3.5-1 identifies an aging management program for each aging effect/mechanism in the table. However, for many of the row entries in LRA Table 3.5-1, the ‘Discussion’ column concludes that the aging effect/mechanism is not applicable for the component(s) at FCS. Although the aging effect/mechanism may not have been observed to date at FCS, the staff considers the inspection for that aging effect during the period of extended operation through an aging management program to be appropriate in many cases. Provide clarification as to whether the aging effects, identified for the following row entries in LRA Table 3.5-1, will be managed during the period of

extended operation by the aging management program that is listed with the row entry:

Row Entry	Aging Management Program
3.5.1.07	Containment ISI
3.5.1.10	Plant specific
3.5.1.12	Containment ISI and Containment Leak Rate Test
3.5.1.16	Structures Monitoring
3.5.1.17	Plant specific
3.5.1.22	Plant specific

Response:

Refer to the response to RAI 3.1-2. For concrete at FCS, even though OPPD has concluded that the AERMs identified for concrete in the GALL Report are not applicable due to the plant's operating experience, OPPD has committed to be consistent with the GALL Report and monitor for the possibility of the AERMs with the programs identified in the GALL Report.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5-2 The staff's expectation is that every component that is identified as requiring an AMR in LRA Tables 2.4.1-1 through 2.4.2.7-1, would have a link to AMR Table 3.5-1, 3.5-2, or 3.5-3 in the LRA. However, during its review, the staff found links to other system groups. Each link to a non-structures group is identified below. For each item, please provide a justification for the link, or provide the correct link to LRA Table 3.5-1, 3.5-2, or 3.5-3:

Component	Table	Link
Calcium Silicate Board in Ambient Air	2.4.1-1	3.3.2.80 (Auxiliary system link)
Auxiliary Bldg Fire Penetration Barriers	2.4.2.1-1	3.3.1.19 (Auxiliary system link) 3.3.1.25 (Auxiliary system link) 3.3.2.51 (Auxiliary system link) 3.3.2.52 (Auxiliary system link) 3.3.2.53 (Auxiliary system link) 3.3.2.54 (Auxiliary system link) 3.3.2.79 (Auxiliary system link)
Auxiliary Bldg Pyrocrete	2.4.2.1-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link) 3.3.2.61 (Auxiliary system link)
Safety Injection and	2.4.2.1-1	3.3.2.36 (Auxiliary system link)

Component	Table	Link
Refueling Water Tank		
Carbon Steel Pipe and Pipe Casing	2.4.2.3-1	3.3.1.05 (Auxiliary system link)
Fire Protection Pyrocrete	2.4.2.3-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link) 3.3.2.61 (Auxiliary system link)
Stainless Steel Strainer Backwash Piping Floor Penetration	2.4.2.3-1	3.3.1.16 (Auxiliary system link)
All Components	2.4.2.5-1	Various Auxiliary system links

Response:

Component	**Table**	**Link**	**Justification**
Calcium Silicate Board in Ambient Air	2.4.1-1	3.3.2.80 (Auxiliary system link)	OPPD lists fire barriers as part of the plant structures in Section 2 of the LRA. The GALL Report (NUREG-1801) includes aging management for fire barriers in Volume 2, Chapter VII, Auxiliary Systems; therefore, the aging management of fire barriers is included in Section 3.3 of the LRA.
Auxiliary Bldg Fire Penetration Barriers	2.4.2.1-1	3.3.1.19 (Auxiliary system link) 3.3.1.25 (Auxiliary system link) 3.3.2.51 (Auxiliary system link) 3.3.2.52 (Auxiliary system link) 3.3.2.53 (Auxiliary system link) 3.3.2.54 (Auxiliary system link) 3.3.2.79 (Auxiliary system link)	OPPD lists fire barriers as part of the plant structures in Section 2 of the LRA. The GALL Report (NUREG-1801) includes aging management for fire barriers in Volume 2, Chapter VII, Auxiliary Systems; therefore, the aging management of fire barriers is included in Section 3.3 of the LRA.
Auxiliary Bldg Pyrocrete	2.4.2.1-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link)	OPPD lists fire barriers as part of the plant structures in Section 2 of the LRA. The GALL Report (NUREG-1801) includes aging management for fire

Component	Table	Link	Justification
		3.3.2.61 (Auxiliary system link)	barriers in Volume 2, Chapter VII, Auxiliary Systems; therefore, the aging management of fire barriers is included in Section 3.3 of the LRA.
Safety Injection and Refueling Water Tank	2.4.2.1-1	3.3.2.36 (Auxiliary system link)	Because of the structural nature of the Safety Injection and Refueling Water Tank, it was included in Section 2.4 of the LRA. The plant specific link was included in Section 3.3 because it is analogous to the spent fuel pool liner included in GALL Report Volume 2, Chapter VII, Auxiliary Systems.
Carbon Steel Pipe and Pipe Casing	2.4.2.3-1	3.3.1.05 (Auxiliary system link)	This is a link for aging of the external surfaces of piping associated with the fire protection system. Since fire protection piping is included in GALL Report Volume 2, Chapter VII, Auxiliary Systems, the link was made to the aging management program for external surfaces of carbon steel components in Section 3.3, Auxiliary Systems, of the LRA.
Fire Protection Pyrocrete	2.4.2.3-1	3.3.2.59 (Auxiliary system link) 3.3.2.60 (Auxiliary system link) 3.3.2.61 (Auxiliary system link)	OPPD lists fire barriers as part of the plant structures in Section 2 of the LRA. The GALL Report (NUREG-1801) includes aging management for fire barriers in Volume 2, Chapter VII, Auxiliary Systems; therefore, the aging management of fire barriers is included in Section 3.3 of the LRA.
Stainless Steel Strainer Backwash Piping Floor Penetration	2.4.2.3-1	3.3.1.16 (Auxiliary system link)	This link is in error. The link should be to 3.5.2.25
All Components	2.4.2.5-1	Various Auxiliary system links	OPPD lists fuel handling equipment and heavy load cranes as part of the plant structures in Section 2 of the LRA. The GALL Report (NUREG-1801) includes aging management for fuel handling equipment and heavy load cranes in Volume 2, Chapter VII, Auxiliary Systems; therefore, the aging management of fire barriers is included in Section 3.3 of the LRA.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-1 In discussing below-grade concrete at FCS in LRA Table 3.5-1, row 3.5.1.07, you have determined that the below-grade environment is relatively benign. This exempts you from having an aging management program for below grade accessible concrete components. However, as the containment tendon gallery is below grade and is accessible for inspection, its condition could provide confirmation as to the benign characteristics of the soil/ground-water environment. Therefore, please provide information regarding the condition of the containment tendon gallery which supports your assessment regarding the benign characteristics of the below-grade media.

Response:

The exterior of the below-grade concrete wall of the tendon gallery is, by definition, inaccessible for inspection. If the reviewer is implying that inspections of the inside of the below-grade tendon gallery wall will provide evidence that the environment on the outside of the wall is not adversely affecting the concrete, then the results of these inspections performed to date indicate that no external degradation is occurring. Although the tendon gallery is not part of the Containment boundary, it is included as part of the Containment inspections. In October 1999, there was no evidence of active concrete degradation (i.e., no residue indicating spalling concrete). Additionally, there were no signs of active seepage and all surfaces were dry. Fine cracks that had been noted in earlier inspections and monitored in subsequent inspections showed no signs of movement from those previous inspections.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-2 LRA Table 2.4.1-1 entry entitled “Containment Grout in Ambient Air” identifies several sections of the LRA Section 3 AMR results that are credited with managing the aging of grout. The staff is unclear with regard to the location of grout within containment. In order to determine whether the credited programs are adequate to manage aging of grout, please clarify the location of grout within the containment and provide information to demonstrate that the containment grout will be adequately managed during the period of extended operation.

Response:

“Containment Grout in Ambient Air” includes grout under baseplates that are not typically exposed to fluids, flowing or otherwise. The table referenced in the RAI provides links to LRA AMR Items that are consistent with the recommendations in the GALL Report and credit the recommended AMPs. This, therefore, appears to be an invalid RAI question since the GALL Report indicates that further evaluation is not required if the indicated component is included in the recommended AMP.

There is an error in Table 2.4.1-1 for the "Containment Grout in Ambient Air" Component Type. The link to LRA AMR Item 3.5.1.23 is incorrect and should not appear. It will be removed.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-3 In discussing the biological shield temperatures in LRA Table 3.5-1, row 3.5.1.10, the applicant states: "Technical Specification Limiting Condition of Operation 2.13 requires that the annulus exit temperature from the nuclear detector cooling system shall not exceed a temperature found to correlate to 150°F concrete temperature." The staff is unclear regarding how the correlation between the annulus exit temperature and the concrete temperature is developed. The staff needs to understand the correlation to have reasonable assurance that the aging effects associated with the concrete elements will be adequately managed during the extended period of operation. Please provide more information regarding the exit temperature, and how the exit temperature from the cooling system controls the temperature of biological shield concrete. What are the operating measured temperatures in the annulus between the reactor vessel and the biological shield wall concrete?

Response:

The Nuclear Detector Cooling System is used to cool the air in the annulus between the reactor vessel and the biological shield. While the nuclear detectors can withstand temperatures considerably higher than 150°F, the elevated temperature could result in reduction in concrete strength through loss of moisture. Each nuclear detector well cooling unit is rated at 100% of the system design capability of 173,000 Btu/hr. A test was performed during Hot Functionals and/or Low Power Tests to determine (1) the correlation between annulus air temperature and concrete temperature, and (2) the rate at which the concrete will heat up if no cooling is available. The results of these tests were used to provide control room indication of concrete temperatures (that is annulus air temperature) and allowable reactor operation time in the event both nuclear detector well cooling units were inoperable. The objective for this specification is to hold the concrete bulk temperature to no greater than 150°F. Temperature sensors are installed in the concrete and in the annulus air discharge. The sensors in the concrete are subjected to neutron flux during operation and are no longer functional. The indicated values for annulus exit temperatures which correlate with concrete temperatures were determined, including a maximum value used to comply with the Tech Spec limit.

Meeting Discussion:

The staff stated that it would like the applicant to revise the response to include more specific information on the correlation between the concrete temperature and the annulus air temperature.

RAI 3.5.1-4 In the last sentence of the “Discussion” column in LRA Table 3.5-1, row 3.5.1.10, the applicant concludes, “Therefore, no portions of concrete containment exceed specified temperature limits and no aging management is required.” The staff notes that the 150°F threshold limit, provided in CC-3400 of ASME Section III, Division 2, and in Appendix A of ACI-349, “Code Requirements for Nuclear Safety Related Concrete Structures,” ensure that the concrete properties will not be significantly affected up to that temperature. However, use of this guidance will not guard against aging degradation of concrete (i.e., cracking, spalling, and resulting reinforcing bar corrosion). The staff believes that these concrete aging effects must be managed to ensure that the intended functions of the associated structures are maintained during the period of extended operation. GALL program XI.S6, “Structural Monitoring Program,” recommends the use of ACI 349.3R-96 for managing the aging of concrete structural components inside the containment. The ACI report recommends the inspection of these structures every five years. Please provide a brief description of the current program(s) used to monitor the condition of the concrete components inside the containment, together with the significant findings of the past inspections. The components of interest are the biological shield walls, the support areas of the reactor vessel, steam generators, and reactor coolant pumps. Include a justification for why the current program(s) is not needed to manage aging of concrete components during the period of extended operation, or add the program(s) to those credited for managing aging during the period of extended operation.

Response:

This question appears to take the information in the Discussion column of LRA AMR Item 3.5.1.10 out of context. Because the information in the Discussion column of that line item is relative to the adverse effects to concrete from elevated temperature only, the quoted statement is relative to elevated temperature degradation only. In Table 2.4.1-1 of the LRA, notice that for every Component Type that includes concrete, there are multiple links to LRA AMR Items. Each of these links addresses a particular AERM(s) relative to concrete that corresponds to a matching GALL Report line item. The Discussion column in each of the LRA AMR Items identifies why OPPD has determined that the applicable AERM(s) in its corresponding GALL Report line item is not applicable to FCS; however, it also identifies that OPPD is crediting the GALL Report recommended AMP for the aging management of the structure anyway. As stated in the response to RAI 3.5.1-2 above, this RAI question appears to be invalid since OPPD is consistent with the GALL Report with the application of the recommended programs. Further information on the operating experience of Containment inspections is provided in the following paragraph, however.

In the case of the FCS Containment, per the LRA AMR Items referenced in Table 2.4.1-1 for the concrete Component Types, inspections are performed of their component parts under both the Structures Monitoring Program and the Containment ISI Program, described in LRA Appendix B Sections B.2.10 and B.1.3, respectively. The containment inspection surveillance test is performed at a frequency of every other refueling outage based on requirements contained in Section 3.5 of the FCS Technical Specifications. Containment inspections have been performed in 1996, 1999, 2001* and 2002 with no evidence of significant structural degradation identified. Condition reports were initiated during the 2002 inspection to document new grease trails from tendon leakage, corroded

supports found on three Safety Injection Leakage Coolers, a missing anchor on a strainer basket, and a broken anchor bolt on a steam generator seismic support.

(*NOTE: The containment shell, dome, and metallic liner were inspected in 2001 to meet new ASME Section XI IWL requirements.)

Meeting Discussion:

The staff stated that the response addresses the containment only. Therefore, the staff requests the applicant to revise the RAI response to provide operating experience and aging management of concrete components subjected to relatively high temperatures (e.g., biological shield walls, the support areas of the reactor vessels, steam also addresses the other components identified in the RAI).

RAI 3.5.1-5 In LRA Table 3.5-1, row 3.5.1.23, the applicant states: “The combinations of components, materials and environments identified in NUREG-1801 are not applicable to FCS.” The GALL report identifies concrete tanks as Group 7 structures, and steel tanks as Group 8 structures. It is unclear to the staff whether the applicant is stating that neither group contains liners. The staff believes that, if the subject structures contain liners, these liners may be needed to ensure the structural integrity of the tanks. On this basis, please clarify whether any Group 7 or Group 8 structures that are within the scope of license renewal and subject to an AMR, contain liners. If so, please provide the basis for why these liners are not needed to maintain the intended function of the subject structures. Specifically, please provide a list of safety-related tanks that are in the FCS yard, in buildings, and those below grade. Please provide materials and environments they are subjected to, and the aging management program(s) applicable to these tanks.

Response:

There is only one Group 7 component, i.e., Class I concrete tank, at FCS. This is the Safety Injection and Refueling Water Tank (SIRWT), which is included in Table 2.4.2.1-1 for the Auxiliary Building and is identified as having a pressure boundary function. That table provides a link to LRA AMR Item 3.3.2.36, which identifies that the tank has a coated carbon steel liner that is managed for aging by the Structures Monitoring Program. LRA AMR Item 3.5.1.23 does not apply to the SIRWT because the liner is not stainless steel as identified in the corresponding GALL Report Items III.A7.2-b and III.A8.2-b.

There are no Class I steel tanks (Group 8) included as structural components within the FCS LRA. All steel tanks subject to AMR are included as mechanical Component Types within their respective system scoping and screening results tables in Section 2.3 of the LRA.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-6 LRA Table 3.5-1, row 3.5.1.16, states that the structures monitoring program is credited for managing various types of aging effects for the subject components. However, in the discussion column, the applicant states that aging management is not required because the concrete at FCS was designed in accordance with ACI 318-63. The statement in the discussion column contradicts the information regarding the structures monitoring program. Please resolve the discrepancy.

Response:

In the Discussion column of LRA AMR Item 3.5.1.16, there are nine items. Item number one indicates that the aging management of the concrete at FCS will be performed with a Structures Monitoring Program that is consistent with the GALL Report. Item numbers two through nine provide specific FCS information regarding the aging mechanisms described in Chapter IIA of the GALL Report. Although the plant specific information (items two through nine) indicates aging management is not required, FCS has indicated in item number one that a program will be credited for managing the aging of concrete for the period of extended operation.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-7 In the discussion column of LRA Table 3.5-1, row 3.5.1.16, the applicant refers to concrete Classes A, B, and C at FCS. The staff is not familiar with these concrete classes. In order to confirm whether aging management is not required for these concrete classes, please provide the definition for each class of concrete, the differences among them, and their applicability.

Response:

There are three classes of concrete at FCS, Classes A, B, and C. Class A concrete is used in the containment shell and containment foundation. Class B concrete is used in the interior concrete structures inside the containment shell, auxiliary building concrete and foundation, tendon access gallery, intake structure, turbine pedestal, circulating water tunnels, service building, turbine building, and other miscellaneous structures. Class C concrete (heavy concrete) is used only in areas where special radiation shielding provisions are required.

Class A concrete has a compressive strength of 5000 psi, water-to-cement ratio of 4.25 gallons/sack or 0.38, minimum cement content is 6.25 sacks/cubic yard, and the entrained air content is 4.75% $\pm$ 0.75%. Class A concrete has a compressive strength of 4000 psi, water-to-cement ratio of 5.0 gallons/sack or 0.44, minimum cement content is 5.50 sacks/cubic yard, and the entrained air content is 5.0% $\pm$ 1.0%. Class C concrete has a compressive strength of 3000

psi, water-to-cement ratio of 6.0 gallons/sack or 0.53, minimum cement content is 5.50 sacks/cubic yard, and the entrained air content is 0.0% (i.e., no air entrainment).

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-8 In the discussion column of LRA Table 3.5-1, rows 3.5.1.16 and 3.5.1.17, the applicant states that periodic monitoring of below-grade water chemistry will be conducted during the period of extended operation. What program(s) will be used to perform this periodic monitoring and describe how this program will monitor below-grade water chemistry?

Response:

Ground water and river water samples were taken in June 2000 and evaluation results were compared to samples taken during plant construction. No significant deviation in sample results was identified. A periodic task will be initiated as part of the Structures Monitoring Program to take ground water samples and compare the evaluation results to previous samples.

Meeting Discussion:

The staff requested that the applicant revise the RAI response to provide more information on the periodic task. Specifically, identify the frequency for taking and evaluating ground water samples.

RAI 3.5.1-9 LRA Table 3.5-1, row 3.5.1.02, states that the bellows at FCS are not exposed to a corrosive environment, therefore stress corrosion cracking is not an aging effect requiring management. Stress corrosion cracking is a concern for bellow assemblies with dissimilar metal welds. This aging effect can occur without an accompanying corrosive environment. Also, examination Categories E-B & E-F, and augmented VT-1 visual examination are used to detect stress corrosion cracking in dissimilar welds. On this basis please provide the basis for not considering the use of Examination Categories E-B & E-F, and augmented VT-1 visual examination of FCS bellows and dissimilar welds for the extended period of operation.

Response:

Tracking due to cyclic loading of these bellows will be managed, per LRA AMR Item 3.5.1.02 (based on GALL Report Items II.A3.1-c and -d), by the Containment ISI and leak rate testing programs which are consistent with programs XI.S1 and XI.S4 outlined in the GALL Report (i.e., the visual examination categories identified in the RAI are included in the credited programs).

Relative to SCC, however, GALL Report Item II.A3.1-d identifies that “In the case of bellows assemblies, SCC may cause aging effects particularly if the material is not shielded from a corrosive environment.” At FCS, there is no corrosive environment from which to shield these bellows assemblies. LRA AMR Item 3.5.1.02 Discussion column Item 4 is based on this clarification in the GALL Report.

Meeting Discussion:

The staff asked the applicant to explain how they determined that a corrosive environment did not exist for the bellows. The applicant stated that the bellows are located in the main steam penetration room, which is an accessible, hot air environment in the auxiliary building, and are inspected periodically. There is no exposure to chlorides or boric acid. The applicant stated that it would revise the response to include this additional information. During the AMR inspection, the staff will review on-site records regarding degradation of the bellows.

3.5.1-10 With respect to items 2.b, 2.c and 2.d of row 3.5.1.12 of LRA Table 3.5-1, the discussion provides generic reasons for why the corrosion of inaccessible areas would not be significant under normal circumstances. However, the staff is concerned that there could be some plant-specific or unexpected situations under which the corrosion could be significant. In order for the staff to have reasonable assurance that corrosion in inaccessible areas is insignificant at FCS, and since the applicant appears to have been doing past monitoring/maintenance work, please provide information on FCS operating experience with regard to corrosion associated with the inaccessible areas for FCS containment liner plates (e.g., liner corrosion at the moisture barrier, corrosion of basemat portion of liner underneath partially cracked containment floor concrete due to borated water spills, etc.), and demonstrate that the AMPs currently in place are adequate for managing the FCS containment liner aging effects for the period of extended operation.

Response:

Review of historical and recent maintenance and corrective action documents did not identify any anomalies which could lead to significant corrosion of the inaccessible areas of the FCS containment liner plates. The most recent inspection of the containment liner and moisture barrier was performed in April 2001 to satisfy ASME Section XI IWE requirements. The inspection identified some areas of corrosion on the liner near the moisture barrier and some separation and trenching of the moisture barrier. Repairs were made to the moisture barrier during the 2002 refueling outage. This included removal of the top portion of the moisture barrier to inspect inaccessible sections of the liner. Only minor surface corrosion was found on the liner extending only 1/8” to 1/4” below the top of the existing joint sealer. Repairs were performed to recoat the liner and restore the moisture barrier. Containment inspections performed under the FCS Containment Inservice Inspection Program and Structures Monitoring Program will ensure the integrity of the liner is maintained.

Meeting Discussion:

The staff stated that it will review the results of the most recent liner inspection during the AMR inspection.

3.5.1-11 With respect to LRA Table 3.5-2, row 3.5.2.25, FCS appears to have containment stainless steel threaded fasteners (the applicant identifies containment stainless steel threaded fasteners in LRA Table 2.4.1-1) which are not addressed in GALL. The applicant has decided that no AMP is needed for stainless steel fasteners in ambient air, whereas the staff is concerned that in a wetted or highly moisturized air environment, an AMP may be needed for the stainless steel fasteners. On this basis, please confirm that, for FCS, there are no containment stainless steel threaded fasteners used in a wetted or highly moist air environment. Otherwise, justify why fasteners in a wetted or moist environment need no AMP to manage loss of material.

Response:

These stainless steel threaded fasteners are for the fuel transfer tube blind flange (containment side). The blind flange is removed prior to filling the refueling canal; therefore, the fasteners are not subject to an environment which would support aging effects.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-12 Considering the vulnerability of concrete structural components, the staff has required previous license renewal applicants to implement an aging management program to manage the aging of these components. The staff position is that cracking, loss of material, and change in material properties are plausible and applicable aging effects for concrete components inside containment as well as for other structures outside containment. For inaccessible concrete components, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive; however, for all other concrete components, inspection through an aging management program is required.

For many of the concrete components listed in LRA Section 2.4, “Scoping and Screening Results: Structures,” the staff was unable to verify that the aging effect(s) identified for these components in LRA Table 3.5-1 will be managed by an appropriate aging management program. Provide clarification regarding the AMR conclusions for:

- containment concrete above grade,
- containment concrete below grade,
- interior containment concrete in ambient air,
- containment grout in ambient air,
- auxiliary building concrete below grade,

- auxiliary building exterior concrete in ambient air,
- auxiliary building interior concrete in ambient air,
- diesel fuel oil tank foundation,
- diesel generator missile shield enclosure concrete below grade,
- diesel generator missile shield enclose concrete in ambient air,
- turbine and service building concrete above grade,
- turbine and service building concrete below grade,
- turbine and service building concrete in ambient air,
- turbine and service building grout in ambient air,
- intake structure - concrete below grade,
- intake structure - concrete exposed to raw water,
- intake structure - concrete exterior in ambient air,
- intake structure - concrete interior,
- duct banks - exterior concrete in ambient air,
- duct banks - concrete below grade,
- duct banks - interior concrete.

For each concrete component identified above, identify the applicable aging effects and the program that will be used to manage each aging effect.

Response:

See response to RAI 3.5-1.

Meeting Discussion:

The staff had no further issues with this response.

RAI 3.5.1-13 Considering the vulnerability of carbon steel structural components, the staff position is that loss of material is a plausible and applicable aging effect for carbon steel components inside containment as well as for other structures outside containment. For carbon steel in an indoor/air-conditioned environment, the staff does not require aging management. In addition, for steel imbedded in concrete in inaccessible areas, the staff does not require aging management if the applicant is able to show that the soil/water environment is nonaggressive.

For many of the carbon steel structural components listed in LRA Section 2.4, “Scoping and Screening Results: Structures,” the staff was unable to verify that the aging effect(s) identified for these components in LRA Table 3.5-1 will be managed by an appropriate aging management program. Provide clarification regarding the AMR conclusions for carbon steel components in LRA Section 2.4 that reference row entry 3.5.1.16 in LRA Table 3.5-1.

Response:

See response to RAI 3.1-2.

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-14 For interior containment concrete in ambient air and containment grout, LRA Table 3.5-1 row entries 3.5.1.15 and 3.5.1.16 are referenced. The 'Discussion' columns for these two row entries appear to contradict each other regarding the applicability of reaction with aggregates as an applicable aging mechanism, which leads to the aging effect cracking. Please clarify whether reaction with aggregates and hence cracking is considered to be applicable for interior containment concrete in ambient air and containment grout.

Response:

See responses to 3.5-1.

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-15 The 'Discussion' column for row entry 3.5.1.07 in LRA Table 3.5-1 appears to indicate that the identified aging effects (change in material properties, cracking, loss of material) for concrete elements (foundation, walls, dome) are not applicable at FCS for below-grade concrete components. This same row entry (3.5.1.07) is also referenced for a number of above-grade concrete components listed in LRA Section 2.4, "Scoping and Screening Results: Structures." Clarify whether the aging effects (change in material properties, cracking, loss of material) for this row entry will or will not be managed for above-grade concrete components.

Response:

See the response to 3.5-1.

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-16 The 'Discussion' column for row entry 3.5.1.16 in LRA Table 3.5-1 indicates that freeze-thaw, which leads to the aging effect cracking, is not an applicable aging mechanism for concrete components at FCS. However, row entry 3.5.1.15 in LRA Table 3.5-1 appears to indicate that cracking resulting from freeze-thaw or reaction with aggregate is an applicable aging effect. Please clarify this discrepancy.

Response:

See responses to 3.5-1.

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-17 For concrete exposed to raw water in the intake structure, LRA Table 2.4.2.3-1 identifies AMR row entries 3.5.1.16 and 3.5.2.32 in LRA Tables 3.5-1 and 3.5-2, respectively. The latter row entry (3.5.2.32) is for component support stainless steel threaded fasteners exposed to ambient air and identifies cracking as the aging effect. Provide clarification regarding the reference to row entry 3.5.2.32 for concrete exposed to raw water in the intake structure.

Response:

AMR item 3.5.2.32 was erroneously included for concrete in raw water and has since been removed from the table.

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-18 In LRA Table 2.4.2.6-1 for component supports, AMR result 3.5.1.28 in LRA Table 3.5-1 is referenced for the lubrite plate in ambient air. Provide clarification regarding the applicability of this row entry for the lubrite plate in ambient air. Specifically, identify the applicable aging effects for lubrite in ambient air and the programs credited with managing the aging effects.

Response:

AMR Item 3.5.1.28 is consistent with GALL Report line item III.B1.1.3-a. That line item specifies its applicability to both steel and non-steel components and parenthetically includes lubrite plates. It addresses the same AERMs and specifies the same AMP. Item 2 in the Discussion column of AMR Item 3.5.1.28 will be revised to read as follows: "Consistent with NUREG-1801, this group includes steel and non-steel components (including lubrite plates) exposed to ambient air at FCS."

Meeting Discussion:

The staff had no further issues with this response.

3.5.1-19 The discussion column of row numbers 3.5.1.16 and 3.5.1.17 of LRA Table 3.5-1 state that the below-grade exterior reinforced concrete at FCS is not exposed to an aggressive environment. To confirm that the below-grade environment is not

aggressive, provide water chemistry data, such as pH, chlorides, and sulfates. In order for the staff to assess the variability of the below-grade environment, please provide the above data since initial plant construction.

Response:

See response to RAI 3.5.1-8.

The Missouri River water was tested periodically from 1973 to 1981. The results showed a pH average of 8.16, chlorides of 12.7 ppm, and sulfates of 200.6 (USAR Section 2.7.1.4 in Table 2.7-3). River water test results from samples taken annually between 1990 and 1999 showed a pH average of 8.24.

The groundwater was tested in August 1966 and the average results showed a pH of 7.3, chloride content of 34 ppm, and sulfate content of 162 ppm (USAR Section 2.7.2.3 in Table 2.7-4).

To verify the river water and groundwater chemistry had not significantly changed over 20-30 years, a chemical analysis was performed in June 2000. Those test results indicated groundwater pH was 7.48, chlorides were 8.0 ppm, and sulfates were 79.0 ppm; river water pH was 8.39, chlorides were 14.0 ppm, and sulfates were 229 ppm.

NUREG-1557 indicates aggressive environments for concrete have a pH less than 5.5, sulfates greater than 1500 ppm, and chlorides greater than 500 ppm

Meeting Discussion:

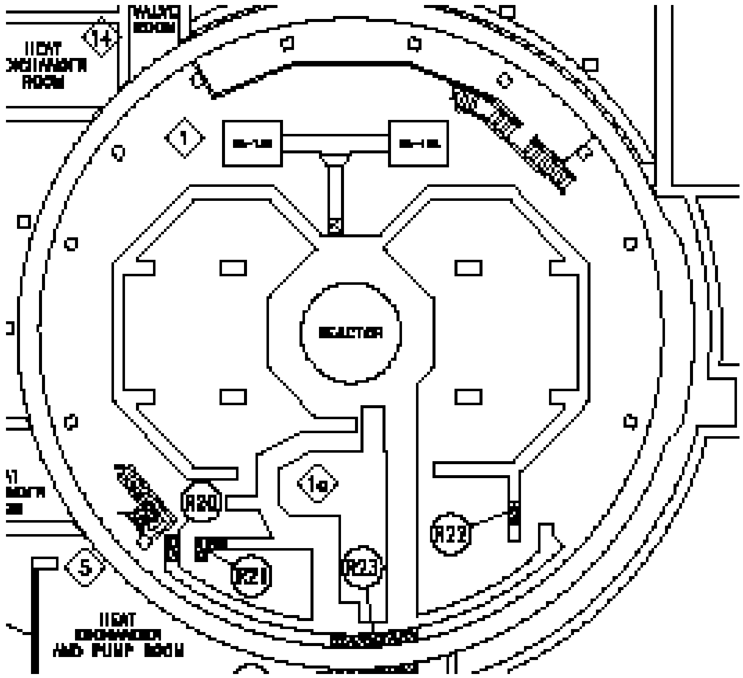
The staff had no further issues with this response.

3.5.3-D1 Based on the information in LRA Table 3.5-3, row number 3.5.3.04, and in FCS AMP B.2.10, the applicant plans to inspect and review the masonry walls in accordance with enhanced GALL program XI.S5, "Masonry Wall Program." As the ungrouted masonry walls in containments are subjected to higher sustained temperatures (> 110°F), humidity, and radiation, please provide the following information for the staff to make a reasonable conclusion regarding the adequacy of these walls during the extended period of operation:

1. location of these walls,
2. environment (temperature, humidity, radiation) to which they are subjected,
3. time-interval for examining these walls, and
4. operating experience related to these walls.

Response:

1. The masonry walls in containment are identified as R20, R21, R22, and R23 in the following figure of the 989' elevation level of containment.



2. Temperature – 120°F
   Humidity – 20 to 100%
   Radiation – 10R/hr averaged over a 40-year life.

3. The masonry walls in containment are inspected during performance of the containment inspection surveillance test which is performed every other refueling outage.

4. Containment inspections performed in 1996, 1999, and 2002 did not identify any degradation of the masonry walls.

Meeting Discussion:

The staff had no further issues with this response.

4.1 Identification of Time-Limited Aging Analyses (TLAAs)

RAI 4.1-1 Table 4.1-1 of the LRA identifies time-limited aging analysis (TLAAs) applicable to FCS. Tables 4.1-2 and 4.1-3 in NUREG-1800 identify potential TLAAs determined from the review of other license renewal applications. The LRA indicates that NUREG-1800 was used as a source to identify potential TLAAs. For those TLAAs listed in Tables 4.1-2 and 4.1-3 of NUREG-1800, which are applicable to PWR facilities and not included in Table 4.1-1 of the LRA, discuss whether there are any calculations or analyses that address these topics at FCS. If calculations or analyses exist that address these topics, discuss how these calculations or analyses were evaluated against the TLAA definition provided in 10 CFR 50.3.

Response:

There are seven TLAAs addressed by the NUREG that are not TLAAs for Fort Calhoun. Only two of those seven TLAAs had some type of documentation related to the topics identified in NUREG-1800. Those two TLAAs which had documentation were reviewed against the criteria of 10 CFR 54.3(a), and the individual results are discussed below:

Metal Corrosion Allowance

This TLAA does not apply to FCS. While corrosion allowances were made consistent with design codes, there are no discrete analyses related to metal corrosion allowances meeting the criteria of §54.3(a).

Polar Crane Fatigue Analyses

The containment polar crane was purchased using a specification based on Electric Overhead Crane Institute standard EOCI-61. EOCI-61 does not address fatigue failure, however a review of the Polar crane against the fatigue criteria of ASME NOG-1 and CMAA (Crane Manufacturers Association of America)-70, Article 3.3.3.1.3, was performed. The polar Crane was judged to have near design cycle loading of only two times every outage which is well below the 20,000 full load cycles that would require fatigue analysis in accordance with ASME NOG-1 and CMAA-70 even with an additional 20-year life.

Meeting Discussion:

The staff noted that the response did not identify the polar crane fatigue analysis as a TLAA. The staff will identify the analysis as a TLAA in the safety evaluation report (SER).

4.3 Metal Fatigue

RAI 4.3.1-1 Section 4.3.1 of the LRA contains a discussion of the transients used in the design of the reactor coolant system components at FCS. The LRA indicates that none of the operational cycles are expected to exceed the number used for the design of these components, for those cycles counted. Provide the following information for each of the transients described in Section 4.3.1 of the LRA:

1. The current number of operating cycles and a description of the method used to determine the number of the design transients from the plant operating history.

2. The number of operating cycles estimated for 60-years of plant operation and a description of the method used to estimate the number of cycles at 60 years.

3. A comparison of the design transients listed in the LRA with the transients monitored by the Fatigue Monitoring Program (FMP) described in Section B.2.4 of the LRA. Identify any transients listed in the LRA that are not monitored by the FMP and explain why it is not necessary to monitor these transients.

Response:

1. The plant operating cycles are recorded in accordance with Standing Order (SO) O-23, "Systems and Equipment Usage Data." Per this procedure, the Operations Engineer and System Engineer review the operating history on a monthly basis and document the number of cycles. The current number of operating cycles is listed below:

Fatigue Cycle Summary

Item	Cycle Description from USAR	Status of Cycle Count Relative to SO O-23	Current Count
1	500 heatup and cooldown cycles at a heating and cooling rate of 100°F/hr.	This cycle is counted and the count is complete.	66
2	10 cycles of hydrostatic testing the reactor coolant system at 3125 psia and at a temperature at least 60°F above the Nil Ductility Transition Temperature (NDTT) of the limiting component.	This cycle is counted and the count is complete.	1
3	200 cycles of leak testing at 2100 psia and at a temperature at least 60°F greater than the NDTT of the reactor vessel.	This cycle is counted and the count is complete.	46
4	400 reactor trips when at 100 percent power.	This cycle is counted and the count is complete.	52
5	40 cycles of loss of turbine load with delayed reactor trip from 100 percent power.	This cycle is counted and the count is complete.	19
6	40 cycles of total loss of reactor coolant flow when at 100 percent power.	This cycle is counted and the count is complete.	5
7	10 cycles of secondary side hydrostatic testing at 1235 psig while the primary side is at 0 psig.	This cycle is counted and the count is complete.	2 per Generator
8	200 cycles of secondary side leak testing at 985 psig while the primary side is at 0 psig.	This cycle is counted and the count is complete.	1
9	5 cycles of loss of secondary system pressure.	This cycle is included in SO-023, but there are no cycles on record.	0
10	5,000 cycles of adding 1000 gpm of 70°F feedwater with the plant in hot standby condition.	This cycle is included in SO-023, but there are no cycles on record.	0

Item	Cycle Description from USAR	Status of Cycle Count Relative to SO O-23	Current Count
11	8 cycles of adding a maximum of 300 gpm of 32°F feedwater, with the steam generator secondary side dry and at 600°F.	This cycle is included in SO-023, but there are no cycles on record.	0
12	4000 cycles (2,000 each direction) of transient pressure differentials of 85 psi across the primary head divider plate due to starting and stopping the reactor coolant pumps.	Exceeding this fatigue limit would require an average of 33 pump starts and stops per year for 60-years. Since this is far in excess of actual pump use, this fatigue cycle will not be exceeded.	
13	15,000 power change cycles over the range of 10 percent to 100 percent of full load with a ramp load change of 10 percent of full load per minute increasing or decreasing.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	
14	2,000 cycles of 10 percent of full load step power changes increasing from 10 percent to 90 percent of full power and decreasing from 100 percent to 20 percent of full power.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	
15	1,000,000 cycles of operating variations of + 100 psi and + 6°F from the normal operating pressure and temperature.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	
16	80 cycles of adding 300 gpm of 32 deg F feedwater with the plant in hot standby condition.	This cycle is not counted under SO -23. These cycles are associated with normal plant operating transients, so they will be accounted for in the Fatigue Monitoring Program	

Meeting Discussion:

The staff requested that the response be revised to clarify whether the head divider plate (table item 12) is the only component for which this scenario applies.

For table items 13 through 16, the applicant clarified that the components will be added to the fatigue monitoring program (FMP). The FMP will determine which TLAA option is appropriate. This will be clarified in the RAI response, the aging management program (AMP) description, and the USAR Supplement.

2. The number of operating cycles estimated for 60-years of plant operation and a description of the method used to estimate the number of cycles at 60-years.

Response:

No formal estimate was made to predict the number of operating cycles which would occur over the 60-year life of the plant. OPPD is simply committing to continue tracking the number of operating cycles and maintain the cycle limits established by the Current Operating Basis through the period of extended operation.

Meeting Discussion:

The applicant clarified that the reason that it has chosen to track the number of operating cycles instead of extrapolating out to 60-years is because one table item (item 5) may exceed 40 cycles over 60-years. For this reason, they have only committed to tracking the cycles. However, the applicant stated that, though they continue to commit only to tracking the cycles, it would revise the RAI response to provide the extrapolated cycle values for 60-years.

3. A comparison of the design transients listed in the LRA with the transients monitored by the Fatigue Monitoring Program (FMP) described in Section B.2.4 of the LRA. Identify any transients listed in the LRA that are not monitored by the FMP and explain why it is not necessary to monitor these transients.

Response:

There are no design basis transients discussed in Section 4.3 of the LRA excluded from the scope of the Fatigue Monitoring Program (FMP). All of these transients will either be counted directly or bounded by the counting of other related transients. A Program Basis Document (PBD) is to be generated to capture both the current and the increased scope of the FMP (1) as a result of the incorporation of automated cycle counting at FCS this year, (2) as a function of the results of the LR iterative performance assessment (IPA) relative to the management of fatigue, and (3) as a result of the environmentally assisted fatigue analysis that has been performed, and recently reviewed and approved, for the Reactor Coolant System. The integration of these enhancements into the FMP has yet to be accomplished. With the development of the PBD, the integration of these activities will be accomplished such that all of the aspects of fatigue relative to FCS operation into the period of extended operation are addressed as described in the LRA. The completion of the PBD and full implementation of the enhanced FMP will take place before the period of extended operation.

Meeting Discussion:

The staff had no further issues with this response.

RAI 4.3.2-1 Section 4.3.2 of the LRA discusses OPPD's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion

references the fatigue sensitive component locations for an older vintage Combustion Engineering plant identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.” The LRA indicates that the later environmental fatigue correlations contained in NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” and NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels,” were considered in the evaluation. Provide the results of the usage factor evaluation for each of the six component locations listed in NUREG/CR-6260.

Response:

Component	Environmental CUF
RPV Inlet Nozzle	0.718
RPV Outlet Nozzle	0.185
RPV Lower head to Shell Juncture	0.020
Surge Line Elbow	1.847*
Charging Line Nozzle	0.688*
Safety Injection Nozzle	0.385
Shutdown Cooling Piping Transition	0.208

The Environmental CUFs are based on the design number of cycles and include the environmental effects per NUREG/CR-6583 and NUREG/CR-5704, with the exception of the asterisked values, which are based on the anticipated number of transient cycles consistent with Table 5-32 of NUREG/CR-6260.

Meeting Discussion:

The staff noted that the CUF values in Table 5-32 of NUREG/CR-6260 are for 40 years. The 60-year values are needed. The applicant stated that they would confirm that the values listed in the response are for 60 years and will provide the basis for the values.

RAI 4.3.2-2 Section A.2.10 of the LRA provides the FMP discussion for the USAR supplement. The discussion indicates that the automated cycle counting software FatiguePro will be used to monitor thermal fatigue of the components in the program. The discussion also indicates that an FCS site-specific evaluation is being performed to address environmental fatigue and that appropriate program enhancements will be made prior to the period of extended operation. However, Section 4.3.2 of the LRA indicates that the environmental fatigue evaluations are complete. This appears to be a discrepancy. Describe the planned FMP enhancements that will be implemented based on the results of the environmental fatigue evaluations.

Response:

OPPD acknowledges that wording in the two referenced LRA Sections on environmentally assisted fatigue evaluations was not consistent. The analysis referred to was completed by the contracted consultant at the end of 2001 just prior to submittal of the LRA. At the time of the submittal, the analysis, which is also alluded to in Section 4.3.3 of the LRA, had not been reviewed and approved for incorporation into the FMP. For this reason, the intent was not to take credit

for it in the LRA other than to say that it was in progress. The review and approval of the analysis has recently been completed. The results of this conservative analysis show that the surge line is the only NUREG/CR-6260 location applicable to FCS where the CUF may exceed 1.0 before the end of the period of extended operation (see response to 4.3.2-1); therefore, environmental fatigue effects at FCS and their inclusion in the FMP need only be considered for the surge line. This is addressed in RAI 4.3.2-3 and its response.

Meeting Discussion:

The staff had no further issues with this response.

RAI 4.3.2-3 Section 4.3.2 of the LRA contains a discussion of the proposed aging management program to address fatigue of the FCS pressurizer surge lines. The discussion indicates the aging management program will consist of an inspection program. The LRA also indicates that the results of the surge line inspections will be used to assess the appropriate approach for addressing environmentally-assisted fatigue of the surge lines. However, Section 4.3.3 of the LRA indicates that a reevaluation of the fatigue usage of critical areas of the surge line will be performed prior to the period of extended operation and that the bounding locations will be included in the FMP. It is not clear to the staff how environmental effects will be factored into the proposed surge line evaluation. Describe how the effect of the reactor water environment will be considered in the reevaluation of the critical areas of the surge line and how the results of this evaluation will be monitored by the FMP.

Response:

The approach for the aging management of the surge line is addressed in Sections 4.3.2 and 4.3.3 of the LRA. This approach will be part of the enhanced FMP.

Meeting Discussion:

The staff noted that the information identified in LRA Section 4.3.2 regarding the elements of the approach that will be used to address environmentally-assisted fatigue should be included in the USAR Supplement.

RAI 4.3.4-1 Section 4.3.4 of the LRA contains a discussion of the analysis of Class II and III components at FCS. The LRA indicates that the USAS B31.1 limit of 7000 equivalent full range cycles may be exceeded during the period of extended operation for the nuclear steam supply system (NSSS) sampling system and that the affected portions of the NSSS sampling system would be tracked by the FMP. Provide the calculated thermal stress range for these affected portions of the NSSS sampling system.

Response:

The small bore piping at FCS was designed and supported based on nomographs developed in accordance with the United States of America Standards (USAS) B31.1 code. Stress ranges for piping locations are therefore not available. As part of the FMP, the sampling piping will be analyzed and stress calculation performed to determine the thermal stress range for this line.

Meeting Discussion:

The staff had no further issues with this response.

4.5 Concrete Containment Tendon Pre-Stress

RAI 4.5-1 For acceptance criterion for tendon prestressing force, the LRA states: “If at any time surveillance testing indicates a decrease in the tendon force below the given limit line, corrective action will be taken in accordance with the Technical Specifications.” This is one of the criterion in IWL-3221. Additionally, 10 CFR 50.55a(b)(2)(viii)(B) requires: “When evaluation of consecutive surveillances of prestressing forces for the same tendon or tendons in a group indicates a trend of prestressing loss such that the tendon forces will be less than the minimum design prestress requirements before the next inspection interval, an evaluation must be performed and reported in the Engineering Evaluation Report as prescribed in IWL-3300.” Based on these requirements, the staff requests the applicant to clarify whether the acceptance criterion in the LRA complies with the requirements of IWL-3221 and 10 CFR 50.55a(b)(2)(viii)(B).

Response:

The acceptance criterion in the LRA does comply with the specified requirements. A regression analysis of forces measured on specific tendons was conducted and included in the tendon testing report. The analysis showed satisfactory results were expected for the next surveillance.

Meeting Discussion:

The staff stated that it would like the response to specifically identify compliance with IWL-3221 and 10 CFR 50.55a(b)(2)(viii)(B).

RAI 4.5-2 10 CFR 50.55a(b)(2)(viii)(B) requires the development of a trend line of measured prestressing forces so that the licensee can decide whether the prestressing tendon forces during the next inspection interval will remain above the “Lower Limit - Dome,” and “Lower-Limit-Wall,” as plotted in Figure 5.10-3 of the FCS USAR. The applicant addresses this TLAA using 10 CFR 54.21 (c)(1)(iii) and Section X.S1 of the GALL report, as part of its operating experience. In order to confirm that the prestressing tendon forces will remain above the lower limits for the dome and wall during the period of extended operation, the staff requests that the applicant provide information related to the trend lines for wall and dome tendons compared to the established lower limits. Guidance for statistical considerations in developing the trend lines is given in Attachment 3 of IN 99-10, Revision 1, “Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments.”

Response:

This trend line analysis is scheduled to be completed prior to the period of extended operation.

Meeting Discussion:

The staff requested that the RAI response be revised to identify the applicant’s commitment to provide the trend line analysis to the staff for review based on the

prestressing force measurements of the past inspections.

4.6 Containment Liner Plate and Penetration Sleeve Fatigue

RAI 4.6-1 Section 4.6 of the LRA discusses the fatigue analysis of the containment liner and penetration sleeves. The LRA indicates that the observed buckling of the liner plate is larger than was assumed in the original analysis. The LRA indicates that this condition has been evaluated and found acceptable for the current term. The LRA further indicates that OPPD will complete an analysis for the 60-year period prior to the period of extended operation. Describe the analysis that was performed to show the containment liner plate/penetration sleeve meets acceptance criteria for the current term. Provide the calculated usage factor obtained from this analysis.

Response:

The recent analysis of the as-found buckling in the liner plate was performed using state-of-the-art, non-linear, 3D Finite Element Analysis methods with loads applied in a fashion similar to the original analysis. The new model includes a section of the concrete shell, the associated liner panel and the embedded anchorage steel restraining the four sides of the modeled panel. An undeformed panel was analyzed first to benchmark the new model against results for a comparable model from the original analysis. A deformed panel distortion of 1/16" inward bowing was modeled in the original analysis to account for construction tolerances, whereas, the recent analysis modeled 1" to bound the observed inward buckling which was observed to be a maximum of about ¾" at elevation 1052' – 0" of Containment. No penetration sleeves are present at this height and none are, therefore, included in the model. Both analyses predict that panel stresses will exceed the material yield strength for the assumed loads.

The purpose of the recent analysis was to determine the effect on fatigue usage caused by the existing buckling and the greater strains that will be incurred as compared to the original analysis. The cumulative fatigue usage factor derived in the original analysis was CUF = 0.05 for 500 cycles of loading. The new analysis derived a CUF = 0.141 for 500 cycles. The allowable usage factor is 1.0. It is not anticipated that even 500 cycles of the assumed loads will be incurred within the 60 year extended period of operation.

Meeting Discussion:

The staff had no further issues with this response.

B.1.3 Containment Inservice Inspection

RAI B.1.3-1 In order to determine whether the applicant's program effectively manages aging in the liner plate, the staff requests the applicant to provide a summary of the significant degradations (i.e. metal thinning in excess of 10% of the nominal thickness of the metal) discovered during the last inspection of the liner in accordance with the program, and a summary of corrective actions taken.

Response:

Inspection of the liner performed in May 2001, identified a maximum thickness loss of approximately 15% at the base of the liner, between the floor expansion

seal and curb at elevation 994’ 6". The minimum thickness measured with UT was 0.216" compared to a nominal thickness of 0.25". The inspection identified some areas of seal separation from the liner and shrinkage below the curb which allowed moisture to collect. Repairs were made to recoat the degraded areas of the liner and restore degraded areas of the moisture barrier during the 2002 refueling outage. This included removal of the top portion of the moisture barrier to inspect inaccessible sections of the liner. Only minor surface corrosion was found on the liner extending only 0.125" to 0.25" below the top of the existing joint sealer.

Meeting Discussion:

The staff had no further issues with this response.

RAI B.1.3-2 NRC inspections during the 1990’s noted a large amount of grease leakage from the tendons at FCS, specifically, in the ring-girder areas of the containment. On the basis of this plant experience, the staff requests to applicant to provide an assessment of such leakages on tendon performance (i.e. absence of corrosion protection and potential degradation of tendon wires) during the extended period of operation, and effectiveness of the actions taken to alleviate the future grease leakages.

Response:

Grease leakage noted on the outer containment walls during the 1990’s resulted from seal leakage from helical tendon upper grease cans. The leakage was characterized as a “large amount” ranges from a few cups to one gallon from a typical volume of more than 50 gallons. This upper seal can leakage has no effect on the long term corrosion of the tendon wires or end attachment, as demonstrated by inspection of the tendon ends when the leaks were repaired. The grease fill procedure was modified to leave additional “head space” for thermal expansion to decrease the number of minor grease leaks on the containment upper helical can seals.

Meeting Discussion:

The staff requested that the applicant revise its RAI response to provide more information on its operating experience with grease leakage. Specifically, describe how the applicant confirmed that there were no effects on the tendon wires as a result of the seal can leakage.

B.1.4 <u>Containment Leak Rate Program</u>

RAI B.1.4-1 For the leak rate testing of FCS containment, the applicant is committing to use GALL Program XI.S4, “10 CFR part 50, Appendix J” in its entirety during the period of extended operation. For Type C (containment isolation valves) testing, the program provides two options for incorporating the Type C tests in the program; (1) as per the requirement of Appendix J, or (2) during the testing of systems incorporating these valves. On the basis of this information, the staff requests the applicant to clarify which option will be used when implementing the Type C testing under FCS containment leak rate testing program.

Response:

OPPD tests the containment isolation valves per the requirements of Appendix J.

Meeting Discussion:

The staff had no further issues with this response.

RAI B.1.4-2 The applicant is requested to provide a summary of significant deviations from the acceptance criteria (e.g., twice the technical specification acceptance criteria) for Type A, Type B, and Type C testing. This operating experience information is needed for the staff to assess the current leaktight characteristics of the FCS containment, and assess its behavior during the period of extended operation.

Response:

No Type A or Type B & C total leakage has significantly exceeded the Technical Specification limit (e.g., twice the technical specification acceptance criteria).

Meeting Discussion:

The staff had no further issues with this response.

B.1.7 Reactor Vessel Integrity Program

RAI B.1.7-1 In a License Amendment dated August 3, 2000, and letters dated November 17, 2000 and February 14, 2001, the licensee provided RT_{PTS} analyses for the materials in the FCS reactor vessel. The August 3, 2000, letter contains Report CEN-636, "Evaluation of Reactor Vessel Surveillance Data Pertinent to the Fort Calhoun Reactor Vessel Beltline Materials." Table 10 in CEN-636, Revision 2, provides the chemistry factor and the predicted RT_{PTS} value through 2033 for each plate and weld in the FCS reactor vessel beltline. Many of the materials RT_{PTS} values are dependent upon surveillance data which could effect their RT_{PTS} value. In addition, one weld is projected to be only 2°F below the PTS screening limit and one weld is projected to be 15°F below the PTS screening limit at the end of the period of extended operation. To determine whether the Reactor Vessel Integrity Program will adequately monitor neutron irradiation embrittlement, provide the following information:

a. Confirm that the RT_{PTS} value identified in Table 10 of CEN-636 is applicable to the end of the period of extended operation for the FCS.

Response:

The RT_{PTS} value identified in Table 10 of CEN-636 is applicable to the end of the period of extended operation for FCS.

b. For each material in Table 10 of CEN-636 identify the projected neutron fluence at the end of the period of extended operation and the neutron flux assumed for future core loadings.

Response:

For the 2-410 and 3-410 axial welds the fluence used was 2.43E+19 n/cm^2. This value conservatively corresponds to the end of the fuel Cycle 41(March 2034) that FCS would be operating in during 2033. In this projection a fast neutron flux equal to that of Cycle 15 was used for all future cycles, i.e., the fluence accumulation rate is 4.0E+17 n/cm^2/EFPY.

For all plate material and the 9-410 circumferential weld, the maximum circumferential fluence occurs at 45^o. A bounding value at 48 effective full-power year (EFPY), which would not be reached until after the period of extended operation, is 3.50E+19 n/cm^2. For the materials below the bounding values of RT_{PTS} would be:

Plate/Weld	CF(^{o}F)	RT_{PTS}	Screening Limit	Margin
D4802-1	82.2	143	270	127
D4802-2	72.0	130	270	140
D4802-3	73.1	131	270	139
D4812-1	83	144	270	126
D4812-2	65	120	270	150
D4812-3	65	120	270	150
9-410	188.41	259	300	41

c. For each chemistry factor in Table 10 of CEN 636 that was calculated using surveillance material, identify the source of the surveillance material.

Response:

All cases where surveillance data were used were for the numerous combinations of the 3-410 tandem arc weld (fabricated with weld wire heats 12008, 13253, and 27204) and for the FCS surveillance plate, D4802-2. The weld materials data used were:

12008/13253:
-Mihama 1 (3 capsules)

27204:
-Diablo Canyon 1 (2 capsules)
-Palisades Supplemental Capsule using FCS nozzle drop-out (1 capsule)

13253:
-DC Cook 1 (4 capsules)
-Salem 2 (3 capsules)

d. Explain how the Reactor Vessel Integrity Program will monitor future core loadings to ensure that no beltline materials will exceed the PTS screening limits in 10 CFR 50.61.

Response:

Compliance with 10 CFR 50.61 is monitored as part of the Program Basis Document for Reactor Vessel Integrity. This program is administered by the FCS Design Engineering-Nuclear Engineering Department. The Nuclear Engineering Department also performs core reload analyses in-house, including

core design. During core loading development core patterns are quantitatively evaluated to ensure that neutron flux to the limiting 60°/300° 3-410 welds is maintained approximately the same as that of Cycle 15, which formed the basis of the fluence analysis. This is done by summing the peripheral fuel assembly relative power densities multiplied by weighting factors derived from the fluence analysis adjoint flux solution. Thus values from a new fuel cycle can be compared to that of Cycle 15 to determine if there has been a net increase or decrease, with a goal of having a time average value the same as Cycle 15. Periodic updates of the fluence analysis are planned. RT_{PTS} is also tracked on an ongoing basis.

e. Identify how the Reactor Vessel Integrity Program will monitor future surveillance capsule data from FCS and other facilities to ensure that no beltline materials will exceed the PTS screening limit in 10 CFR 50.61 or the Charpy upper-shelf energy screening criteria in Appendix G, 10 CFR Part 50.

Response:

Section 4.2 of the Program Basis Document for Reactor Vessel Integrity includes a schedule for obtaining applicable surveillance data from other plants to ensure that the chemistry factors of CEN-636 remain applicable. The FCS surveillance program was recently revised and approved by the NRC staff (Letter from NRC (S. Dembeck) to OPPD (R. T. Ridenoure) dated May 2, 2002, "Fort Calhoun Station, Unit No. 1 - Reactor Vessel Surveillance Capsule Removal Schedule Change (TAC No. MB3422)”). The next FCS surveillance capsule to be removed is W-275S at 33.6 EFPY. This supplemental capsule contains the limiting weld material 12008/13253 (Maine Yankee nozzle drop-out) as well as 27204 (FCS nozzle drop-out). In addition, if any major changes in plant operation do affect PTS or USE projections, reanalysis will be performed to ensure compliance with 10 CFR 50.61 or 10 CFR 50, Appendix G, as applicable.

Meeting Discussion:

The staff requested that the response to Part b of the RAI document the current EFPY, capacity factor, and neutron fluence, and explain how the neutron fluence will be managed such that the fluence in 2033 will not exceed the fluence value assumed for the axial welds.

B.2.3 <u>Diesel Fuel Monitoring and Storage</u>

RAI B.2.3-1 Leak detection is being employed to monitor the condition of the tank in lieu of ultrasonic testing. The staff believes that ultrasonic testing allows for the detection of aging effects in sufficient time to take corrective action to maintain the component’s intended function. Detection of a leak indicates that significant fuel oil tank degradation has already occurred. On this basis, the staff believes that leak detection is an insufficient means to detect tank degradation. Therefore: (1) provide an aging management program that will adequately detect tank degradation in sufficient time to allow for corrective action before loss of the tank’s intended function, or justify how leakage detection will accomplish this goal, (2) discuss the corrective actions that would be taken if leakage is detected, (3) clarify whether inspections will be performed in the other storage

tanks which credit this program for aging management, (4) describe the aging management of other low points of the system where impurities can accumulate.

Response:

(1&2) The Diesel Fuel Monitoring and Storage Program is the aging management program which will detect Fire Protection Fuel Oil tank degradation in sufficient time to allow for corrective action before loss of the tank's intended function. Ultrasonic testing cannot be performed on this tank due to inaccessibility, so leak detection was chosen as an alternate method to maintain the tank's intended function.

The Fire Protection Diesel Fuel Oil Tank is above ground, surrounded by gravel, and enclosed in a concrete structure. The concrete structure is surrounded by a concrete berm. The enclosure has a drain valve, and drains to the berm area. The Diesel Fuel Monitoring and Storage Program credits two leak detection activities. The first activity involves operator rounds recording whether any oil sheen is seen in this berm area. The second activity is to identify via level readings any leakage from the tank between monthly surveillances, while accounting for periodic oil replenishment. Leak detection is adequate to maintain system design requirements, because OPPD has seven days to restore the inoperable equipment to operable status. Seven days is ample time to make necessary repairs or bring in a portable diesel fuel supply.

(3) Inspections (i.e., UT and/or visual) will be performed in the other storage tanks which credit this program for aging management.

(4) Low points of the system include: strainers, filter housings, and piping. Strainers and filter housings are visually inspected, and piping is blacklighted and visually inspected for leakage.

Meeting Discussion:

The staff stated that it would like the response to include the drawing and a discussion of the operating experience of the tank. Also, add that evidence of leakage is checked daily and detected immediately.

RAI B.2.3-D2 The applicant proposes to inspect the diesel fuel oil day tanks and to perform a fuel analysis of the fire protection day tank. In order to evaluate whether these activities will adequately manage aging in the subject components, please discuss the nature of the fuel analysis and day tank inspection, including the constituents to be analyzed, the frequency of the analyses and inspections, the acceptance criteria, and the corrective actions if degradation is found.

Response:

The day tank activities addressed in this question are enhancements and are not the only aging management activities for these tanks. This question is answered by OPPD being consistent with the GALL Report Volume 2, Section XI.M30, Fuel Oil Chemistry Program; however, the following is provided to address the staff's specific request for detail.

The Diesel Generator (DG) day/engine tanks will be cleaned, flushed, and visually inspected every third refueling outage; the fire protection day tank will have a one-time boroscope inspection performed. The DG Day Tanks have water and sediment (W&S) performed monthly, the DG engine tanks have W&S semiannually and microbiological activity performed semiannually; the fire protection day tank will be sampled quarterly for W&S and semiannually for microbiological activity. The acceptance criterion for W&S is <0.05 V% and for microbiological activity is "none detectable." Due to the monthly surveillance runs, the fuel in these day/engine tanks does not remain stagnant and would not warrant quarterly analyses. There is no history of degradation at FCS in the fuel oil system; however, if degradation is found which exceeds Class C cleanliness, then a Condition Report is written and corrective action is taken based upon the Corrective Action Program and any case-specific evaluations.

NOTE: Class C cleanliness has the following criteria:

- Thin uniform rust or magnetite films are acceptable.
- Scattered areas of rust are permissible provided that the area of rust does not exceed 15 square inches in one square foot on corrosion resistant alloys.

Meeting Discussion:

The staff stated that the response should be revised to describe the results of the visual inspections and state that no significant degradation was found at the tank bottom.

RAI B.2.3-3 It is stated under "Parameters Monitored/Inspected," that particulate analysis of fuel oil is performed but is not credited for aging management. The staff requests the applicant to confirm whether the diesel fuel oil quality is monitored for water and sediment contamination in accordance with ASTM Standards D1796 and D2709, as stated in XI.M30 of the GALL Report.

Response:

OPPD only uses ASTM D2709 for water and sediment analysis. The use of the word "and" is confusing in this question, as ASTM D2709 is a newer method specific to Middle Distillate Fuels (which includes Diesel Fuel #2), whereas ASTM D1796 was an older method for all fuel oils. There would be no need to use both. In accordance with ASTM D2709, "Test Method D1796 is intended for higher viscosity fuel oils."

Meeting Discussion:

The staff had no further issues with this response.

B.2.4 Fatigue Monitoring Program

RAI B.2.4-1 Section B.2.4 of the LRA describes the FCS FMP. The first paragraph in Section B.2.4 indicates that the scope of the FMP includes those plant specific components identified in Table 3.1.2 of the application for which the FMP is identified as an aging management program. However, Table 3.1.2 only lists the FMP as an aging management program for the reactor vessel internals-flow skirt. Clarify the scope of the components covered by the FMP.

Response:

The last sentence of that paragraph should read, “The scope of the Fatigue Monitoring Program includes those components identified in Section 4.3 of this application and those specific components identified in Table 3.1.2 of this application for which the Fatigue Monitoring Program is defined as an aging management program.”

The latter part of this sentence refers only to the Flow Skirt as identified in LRA AMR Item 3.1.2.10. All of the other applicable components are included under LRA AMR Items 3.1.1.01, 3.1.2.01, 3.1.3.03, and 3.4.1.01. These AMR Items direct the reader to the applicable sub-sections of Section 4.3 of the LRA.

Meeting Discussion:

The staff had no further issues with this response.

RAI B.2.4-2 Section B.2.4 of the LRA discusses the operating experience at FCS that led to enhancements to the FMP. The LRA indicates that an assessment of the operation of the Chemical and Volume Control System (CVCS) was performed to ensure that the appropriate transients were monitored by the FMP. Describe the enhancements to the FMP that resulted from this assessment.

Response:

In 1997, a plant Condition Report was generated to document concerns about the operation of the CVCS relative to the consistent monitoring and tracking of thermal cycles for specific components within the system. The CR resulted in the performance of an Engineering Assessment to document a review of system Design Basis Documents, the USAR, Technical Specifications, and other documents to determine cycle counting requirements. This review resulted in revisions to some of these documents. An operating history review was performed to determine the actual number of cycles that the components of concern actually experienced. Part of this review was to ensure that the thermal cycles counted were, in fact, a result of design basis conditions that merited inclusion in the cycle counting. The discussion in Section 4.3.1 of the application, relative to the CVCS, reflects the findings of the assessment. The components that were in question are monitored and tracked as required and are to be part of the FMP.

Meeting Discussion:

The staff requested that the applicant clarify that it had found that it did not have good knowledge of the number of thermal cycles for the system, and therefore decided to reconstitute the cycle information. After that, tracking of thermal cycles would be done in accordance with the FMP.

B.2.5 Fire Protection

RAI B.2.5-1 LRA Section B.2.5 states that the Fire Protection Program is consistent with XI.M26, “Fire Protection”, and XI.M27, “Fire Water System”, as identified in the GALL report, with certain enhancements to several program elements. In order for the staff to evaluate the adequacy of the applicant’s fire protection program and reach a conclusion that it is consistent with the guidance in the GALL report,

the staff requests that the applicant confirm the following:

(1) The additional guidance which will be added to the diesel fire pump maintenance procedure during enhancements will ensure that the diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detecting any degradation of the fuel supply line.

Response:

The enhancement identified in the license renewal application for Fire Protection Program B.2.5 was to add specific guidance to the diesel fire pump maintenance procedure to inspect the diesel fire pump fuel line and zinc plug for corrosion or mechanical damage. This enhancement will be implemented prior to the period of extended operation. The diesel fire pump maintenance procedure currently contains guidance to run the pump and check for leaks, abnormal sounds, or other abnormal operating conditions. This enhancement will not address monitoring of the diesel fire pump during the performance of other functional tests or inspections.

For performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests, the diesel fire pump is started locally by Operations personnel who observe the pump for any signs of degradation or improper performance.

(2) The guidance which will be added to halon and fire damper inspection procedures will include periodic visual inspection and function tests at least once every six months to examine signs of degradation of the halon/carbon dioxide fire suppression system. The suppression agent charge pressure will be monitored in the test. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damaged dampers are observed during these tests. Inspection will be performed at least once every month to verify that the extinguishing agent supply valves are open, and the system is in automatic mode.

Response:

The enhancement identified in the license renewal application for Fire Protection Program B.2.5 was to add specific guidance to the halon and fire damper inspection procedures to inspect halon system components and fire dampers for corrosion, mechanical, and physical damage. This enhancement will be implemented prior to the period of extended operation.

Halon and fire damper inspection procedures include periodic visual inspections and functional tests every 18-months to examine signs of degradation of the halon fire suppression system. Although the suppression agent charge pressure is checked on a semiannual basis and inspections are performed on a monthly basis that verify that the extinguishing agent supply valves are open and that the system is in automatic mode, these activities are not required for license renewal. Per interim staff guidance, these activities are not aging management related since the valve line-up inspection, charging pressure inspection, and automatic mode of operation verification are operational activities pertaining to

system or component configurations or properties that may change.

(3) The specific guidance which will be added related to the fire door inspections will ensure that hollow metal fire doors are visually inspected at least once bimonthly for holes in the skin of the door. Fire door clearances are also checked at least once bimonthly as part of an inspection program. Function tests of fire doors are performed daily, weekly, or monthly (which may be plant specific) to verify the operability of automatic hold-open, release, closing mechanisms, and latches.

Response:

The enhancement identified in the license renewal application for Fire Protection Program B.2.5 was to add specific guidance to the fire door inspection procedures to inspect for wear and missing parts. This enhancement will be implemented prior to the period of extended operation.

Inspections of fire doors for holes, clearances, and proper operation of opening, latching, and closure mechanisms within the specified frequencies are currently included in the FCS Fire Protection Program with the exception of the frequency of inspection for fire door clearances. A revision to the inspection frequency for fire door clearances is currently in process to meet the bimonthly requirement.

Meeting Discussion:

The staff had no further issues with this response.

RAI B.2.5-2 The staff has proposed a revision to the Fire Protection System aging management program inspection criteria in the GALL report for wall thinning of piping due to corrosion. The revised staff' position states that each time the system is opened, oxygen is introduced into the system, and this accelerates the potential for general corrosion. Therefore, the staff has recommended that a non-intrusive means of measuring wall thickness, such as ultrasonic inspection, be used to detect this aging effect. The staff recommends that, in addition to a baseline ultrasonic inspection of the fire protection piping that is performed before exceeding the current licensing term, the applicant should perform ultrasonic inspections at 10-year intervals thereafter.

Verify whether the inspection criterion for the applicant's fire protection program conforms with the staff position, as outlined above.

Response:

Enhancements will be made to the Fire Protection Program prior to the period of extended operation to implement the requirements of the interim staff guidance.

Meeting Discussion:

The staff had no further issues with this response.

RAI B.2.5-3 The program description for XI.M27 states that underground piping (among other components) is to be managed by the program. However, the program does not address aging management of underground piping. In order to evaluate whether the applicant's fire protection program will adequately manage aging of

underground piping in the fire water system, please describe the environmental and material conditions that exist on the interior surface of below-grade fire protection piping, and demonstrate how the above-ground piping conditions can be extrapolated to determine the belowground piping conditions, and how the fire protection program will manage aging of underground piping. If a meaningful extrapolation cannot be made, demonstrate how underground piping will be adequately managed during the period of extended operation to assure maintenance of the component intended function.

Response:

Portions of the Fire Protection System piping that are underground are made of asbestos-cement or cast iron with a cement lining. For these materials, an aging management evaluation determined that aging management is not required because the interior of these pipes is not exposed to an aggressive environment (pH<5.5, sulfates>1500ppm, and chlorides>500ppm). Under normal conditions, the system is filled with potable water whose pH, sulfate, and chloride content is within these limits. If untreated raw water is injected into the system, the system is flushed and refilled with potable water. The cement lining of cement-lined cast iron piping provides it with an added feature to prevent the loss of material of the base metal due to corrosion. The cement lining also prevents an internal buildup of turbucles that would contribute to degradation of the pipe flow characteristics. In addition to the inspection activities, the testing features of the Fire Protection Program provide assurance that the entire system can perform its intended function. A visual as-found inspection performed on a section of the FP piping during modification/maintenance work in May 2000 identified that the internal surfaces of the underground piping were clean with a little oxidation on the piping wall.

Meeting Discussion:

The staff stated that it would like the response revised to identify the type and thickness of the cement lining.

RAI B.2.5-4 The staff is concerned that the applicant's fire protection program may not adequately manage aging of coatings in steel structures, since neither XI.M26 nor XI.M27 address coatings. On this basis, the staff requests the applicant to identify any steel structures within the scope of license renewal and subject to an AMR which depend on coatings to protect the steel structures from age-related degradation. For any such coatings, describe the aging management activities that manage the aging effects for the coatings and identify what aging management program performs these activities.

Response:

No steel structures within the scope of license renewal and subject to an AMR depend on coatings to protect the steel structure from age-related degradation.

Meeting Discussion:

The staff stated that it would like the response revised to identify the coatings on steel structures at FCS and to clarify that the applicant manages aging of the steel underneath the coatings.

RAI B.2.5-5 LRA Section B.2.5 states that the applicant's AMP is consistent with GALL AMPs XI.M26, "Fire Protection," and XI.M27, "Fire Water System." The staff has finalized interim staff guidance (ISG) to revise the fire protection system AMPs in the GALL report. The relevant portions of the ISG are summarized below.

1. <u>Staff Position for Wall Thinning of Fire Protection Piping Due to Internal Corrosion</u>

Fire Protection piping is typically designed for a 50-year life in industrial applications. The limiting aging mechanism is general corrosion. Because the general corrosion of FP piping is typically very uniform, loss of intended function as a result of catastrophic failure caused by wall thinning throughout the system is possible and needs to be managed. However, internal inspections (performed during each refueling cycle by disassembling portions of the FP piping), as stated in NUREG-1801, Chapter XI.M27, "Fire Water Systems," are not the best means to detect this aging effect. Each time the system is opened, oxygen is introduced into the system and accelerates the potential for general corrosion. Therefore, the staff recommends that a non-intrusive means of evaluating wall thickness, such as volumetric inspection or plant maintenance inspection, be used to detect this aging effect.

The staff initially considered that a one-time ultrasonic inspection performed near the end of the operating term would be sufficient to detect wall thinning. However, further evaluation determined that it may be difficult to justify a one-time ultrasonic inspection, in light of the possibility of changes in operating conditions that may require the applicant to open the FP systems more frequently (e.g., for the 50-year service life sprinkler head testing) and allow oxygen in. Therefore, the staff is recommending that, in addition to a baseline wall thickness evaluation of the fire protection piping before exceeding the current license term, the applicant should perform pipe wall thickness evaluations at plant-specific intervals during the period of extended operation. The plant-specific inspection intervals are to be determined by engineering evaluation of the FP piping to detect degradation prior to the loss of intended function.

As an alternative to pipe wall thickness evaluations, an applicant may use its plant maintenance process to include a visual inspection of the internal surface of the FP piping upon each entry to the system for routine or corrective maintenance, as long as the applicant can demonstrate that it will perform inspections (based on past maintenance history) on a representative number of locations on a periodic basis. As part of these inspections, applicants need to be sensitive to wall thickness to ensure against catastrophic failure, and to the inner diameter of the piping, as it applies to the flow requirements of the FP system.

Response:

This RAI appears to be a duplicate of B.2.5-D2. Refer to B.2.5-D2 response.

As part of the review of this issue and the above stated approach, a concern was raised as to the inspection specifications of the internal surface of below grade FP piping. The staff acknowledges that some applicants may be able to demonstrate that the environmental and material conditions that exist on the interior surface of below grade FP piping are similar to the conditions that exist within the interior surface of the above grade FP piping. If an applicant makes

such a demonstration, the staff agrees that the results of the interior inspections of the above-grade FP piping can be extrapolated to evaluate the interior condition of the below grade FP piping. If not, additional inspection activities are needed to provide reasonable assurance that the intended function of below grade FP piping will be maintained consistent with an applicant’s current licensing basis for the period of extended operation.

Response:

This RAI appears to be a duplicate of B.2.5-D3. Refer to B.2.5-D3 response.

2. <u>Staff Position for Testing of Sprinkler Heads</u>

National Fire Protection Association (NFPA) 25, 1999 Edition, Section 2.3.3.1, “Sprinklers,” states, “where sprinklers have been in place for 50-years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing.” NFPA 25 also contains guidance to perform this sampling every 10-years after the initial field service testing.

The 50-year service life of sprinkler heads does not necessarily equal the 50th year of operation in terms of licensing. The service life is defined from the time the sprinkler system is installed and functional. In most cases, sprinkler systems are in place several years before the operating license is issued. However, sprinkler systems in some plants may have been installed after the plant was placed in operation. The staff interpretation, in accordance with NFPA 25, is that sprinkler head testing should be performed at year 50 of sprinkler system service life, not at year 50 of plant operation, with subsequent sprinkler head testing every 10-years thereafter.

On the basis of this ISG, the staff requests the applicant to discuss how it plans to follow the guidance in the ISG, and how this will be reflected in AMP B.2.5.

Response:

Prior to the period of extended operation, OPPD will make enhancements to the Fire Protection Program to develop a task/procedure to test/replace sprinkler heads, which have been installed and functional for 50-years, and to test sprinkler heads every 10-years thereafter.

Meeting Discussion:

The staff had no further issues with this response.

The staff interpretation, in accordance with NFPA 25, is that sprinkler head testing should be performed at year 50 of sprinkler system service life, not at year 50 of plant operation, with subsequent sprinkler head testing every 10-years thereafter.

On the basis of this ISG, the staff requests the applicant to discuss how it plans to follow the guidance in the ISG, and how this will be reflected in AMP B.2.5.

Response:

Prior to the period of extended operation, OPPD will make enhancements to the Fire Protection Program to develop a task/procedure to test/replace sprinkler heads, which have been installed and functional for 50-years, and to test sprinkler heads every 10-years thereafter.

Meeting Discussion:

The staff had no further issues with this response.

/***RA***/

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Enclosure: As stated

cc w/encl: See next page

September 23, 2003

Response:

Prior to the period of extended operation, OPPD will make enhancements to the Fire Protection Program to develop a task/procedure to test/replace sprinkler heads, which have been installed and functional for 50-years, and to test sprinkler heads every 10-years thereafter.

Meeting Discussion:

The staff had no further issues with this response.

/***RA***/

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Enclosure

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