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Subject: Arkansas Nuclear One - Unit 1
Docket No. 50-313
License No. DPR-51
License Renewal Application RAIs (TAC No. MA8054)

Gentlemen:

By letters dated April 25, 2000 (1CNA040006), May 5, 2000 (1CNA050002), and June 1, 2000 (1CNA060002), the NRC requested additional information concerning the Arkansas Nuclear One, Unit 1 (ANO-1) License Renewal Application (LRA). Attached are the responses to the requests for additional information (RAIs) pertaining to the reactor coolant system Sections 2.3.1.3, 2.3.1.4, 2.3.1.7, 3.2.2, 3.2.3, 3.2.6, 3.2.7, 3.2.8, 4.3, 4.7, and 4.8 of the ANO-1 LRA. Should you have any further questions, please contact me.

Very truly yours,

Jimmy D. Vandergrift
Director, Nuclear Safety Assurance

JDV/nbm
Attachment

A082

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Request for Additional Information Regarding ANO-1 LRA Reactor Coolant System Sections 2.3.1.3, 2.3.1.4, 2.3.1.7, 3.2.2, 3.2.3, 3.2.6, 3.2.7, 3.2.8, 4.3, 4.7, and 4.8, dated April 25, 2000 (1CNA040006), May 5, 2000 (1CNA050002), and June 1, 2000 (1CNA060002)

2.3.1-2 **The application stated that overpressure protection for the reactor coolant system (RCS) is provided by two code safety valves and one power operated relief valve installed on the pressurizer. Provide the following clarifications:**

- **Are the bodies of these valves within the scope of license renewal and subject to an aging management review (AMR)? Identify where in the LRA is the AMR, or provide a justification for the exclusion of these valve bodies from aging management requirements.**

- **Does ANO-1 take credit for the pressure reducing function of the water spray nozzle of the pressurizer to lower RCS pressure during a design basis event? If so, identify where in the LRA is the pressurizer spray nozzle included within the scope of license renewal, and subject to an AMR or provide a technical justification for excluding the spray nozzle from being subject to an aging management review. (The staff understands that the subject spray nozzle does not perform a pressure boundary function.)**

The bodies of the safety relief valves and the power-operated relief valve are within the scope of license renewal and are subject to aging management review at ANO-1. Section 2.3.1.3 of the ANO-1 LRA lists pressure retaining parts of ASME (American Society of Mechanical Engineers) Class 1 valves as subject to an aging management review. As discussed in Section 2.3.1.3, ANO-1 is bounded by the Babcock and Wilcox Owners Group (BWOG) generic report, BAW-2243A. ANO-1 does not credit pressurizer spray to mitigate either design basis events or any other regulated events.

2.3.1-3 **The application indicates that the pressurizer and once-through steam generator (OTSG) manhole gaskets are not included within the scope of license renewal. Provide a technical justification for excluding these gaskets from the scope of licensee renewal consistent with the rule and staff guidance. In addition, indicate whether the pressurizer manhole gaskets are covered under Generic Letter (GL) 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components.**

The pressurizer and OTSG manway gaskets are excluded from aging management review in accordance with NRC Safety Evaluation Report (SER) for BAW-2244A. In Section 3.1.1, the Staff concluded that the gasket was part of the bolted connection and exists to minimize leakage and is not solely responsible for providing the pressure boundary or supporting a structural load. The Boric Acid Corrosion Prevention Program includes components that are exposed to boric acid leakage. If a gasket is the source of leakage, it would be addressed in the program.

2.3.1-5 **Section 2.3.1.7 of the LRA identified OTSG items that are subject to an AMR. Safety or relief valve bodies were not identified in the list. Please clarify whether there are any valves that are associated with the OTSGs which perform any of the OTSG intended functions identified in the LRA, such as, the pressure boundary function. If so, identify where in the LRA is the AMR, or provide a justification for the exclusion of these valve bodies from aging management requirements.**

Safety or relief valve bodies are not attached to the OTSGs. OTSG overpressure protection on the primary side is provided by pressurizer code safety valves, which are discussed in BAW-2243A and Section 2.3.1.3 of the ANO-1 LRA and were subject to an aging management review. OTSG overpressure protection on the secondary side is provided by valves in the main steam system, which are discussed in Section 2.3.4.1 of the ANO-1 LRA and were subject to an aging management review.

2.3.1-6 **Section 2.3.1.7 of the LRA states that "Secondary piping attached to the OTSG nozzles, including the main and auxiliary feedwater headers and riser piping, is addressed in Section 2.3.4.2." However, Section 2.3.4.2 does not address main and auxiliary feedwater headers and riser piping. Identify where in the LRA is the main and auxiliary feedwater headers identified as being within the scope of license renewal and subject to an AMR, or provide a justification for the exclusion of these headers from an AMR.**

Section 2.3.1.7 does address the main and auxiliary feedwater headers and riser piping and documents that these components are subject to aging management review. The quoted statement was clarifying that Section 2.3.4.2 of the ANO-1 LRA addresses the secondary piping that is attached to the main and auxiliary feedwater headers and riser piping.

3.3.2.2.2-1 **Table 4-1 of BAW-2243A, "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping" identifies aging management programs (AMPs) to manage the aging effects of RCS piping component groupings. The components are grouped in accordance with their types, materials of construction and aging effects. Table 3.2-1 of the license renewal application (LRA) lists AMPs at ANO-1 to manage the aging effects in its RCS piping and letdown cooler components. Comparing both tables, the staff finds that several AMPs recommended in Table 4-1 of the topical report are not included in Table 3.2-1.**

(a) **Identify the ASME Section XI, Examination Categories for dissimilar welds, small-bore piping, and cast austenitic stainless steel (CASS).**

As discussed in Section 4.3.1 of Appendix B of the ANO-1 LRA, Entergy Operations has implemented a risk-informed methodology to select RCS piping welds for inspection in lieu of the requirements specified in the 1992 Edition of ASME Section XI, Table IWB-2500-1, Examination Category B-J. The risk-informed approach is based on Code Case N-560 and does include provisions for the examination of dissimilar metal welds that are not inspected in accordance with Examination Category B-F, "Pressure Retaining Dissimilar Metal Welds in Vessel Nozzles." Since the dissimilar metal welds in ASME Class 1 piping are made from Alloy 82/182, cracking by primary water stress-corrosion cracking (PWSCC) was identified as an aging effect. The dissimilar metal piping welds that are inspected at ANO-1 are summarized in the NRC SER of the ANO-1 risk-informed inservice inspection submittal (Letter from the NRC to Mr. C. Randy Hutchinson entitled "Risk-Informed Alternative to Certain Requirements of ASME Code Section XI, Table IWB-2500-1 at Arkansas Nuclear One, Unit 1 (TACMA2023),"August 25, 1999, Docket No. 50-313).

The dissimilar metal welds that connect pressurizer vessel nozzles to attached safe-ends are addressed in Table 3.2-1 of the ANO-1 LRA. Due to an administrative error, dissimilar metal welds that connect the reactor vessel nozzles to attached safe-ends were omitted from Table 3.2-1. Specific omissions from Table 3.2-1 under the reactor vessel items include the core flood nozzle to stainless steel safe-end and the control rod drive mechanism (CRDM) Alloy 600 nozzle to stainless steel adapter welds. The primary OTSG nozzles do not have attached safe-ends and do not have dissimilar metal welds.

The ANO-1 small-bore piping and small-bore nozzle inspection is discussed in Section 4.3.8 of Appendix B of the ANO-1 LRA. The ANO-1 risk-informed method to select piping welds for inspection adequately addresses the issue of cracking of small-bore piping for license renewal.

ASME Class 1 items fabricated from cast austenitic stainless steel include selected RCS boundary valves, reactor coolant pump (RCP) casings, and miscellaneous reactor vessel internals items. Reduction of fracture toughness was identified as an applicable aging effect for CASS items. Aging management of RCS boundary valves is discussed in Section 3.2.2 of the ANO-1 LRA. Aging management of the RCP casings is in accordance with Code case N-481 as discussed in Section 3.2.7 of the ANO-1 LRA. Aging management of reactor vessel internals items fabricated from CASS is addressed by the RVIAMP as discussed in Section 3.5 to Appendix B of the ANO-1 LRA.

(b) Identify the augmented inservice inspection (ISI) plan for high pressure injection (HPI)/make up (MU) branch connections and thermal sleeves in response to GL 85-20, "Resolution of Generic Issue 69: High Pressure Injection/Make-up Nozzle Cracking In Babcock and Wilcox Plants."

Augmented inspections of the HPI/makeup connections are discussed in Section 4.3.4.4 of the ANO-1 LRA. These augmented inspections will be carried forward to the period of extended operation.

(c) Provide revised Tables 3.2-1 in order to correct the discrepancies.

Corrections to Table 3.2-1 are captured through specific responses to the NRC RAIs.

3.3.2.2.2-2 **Table 2.3-2 of the LRA contains the ANO-1 response to the Renewal Applicant Action Items identified in the staff's safety evaluation concerning BWOG Report BAW-2243. BAW-2243 addresses the reactor coolant system piping. In its safety evaluation, the staff indicated that a license renewal applicant would have to provide additional details regarding a one-time augmented volumetric inspection of the Alloy 82/182 clad flowmeter section of the hot leg. Table 3.2-1 of the LRA indicates that the hot leg flowmeter assembly will be managed by the Alloy 600 program. The Alloy 600 program is described in Appendix B, Section 4.1 of the LRA. The program discussion does not specifically address the flowmeter section of the hot leg. Provide the plan and program to perform a volumetric inspection of the carbon steel from the exterior of the flowmeter assembly element to determine gross structural integrity, as stated in Section 4.4.1 of the BAW-2243A.**

The Alloy 82/182 cladding and Alloy 600 flow ring that are attached to the hot leg flowmeter element are considered in ranking items for susceptibility to PWSCC. These items were not among the top 3 locations with respect to susceptibility to PWSCC as discussed in Section 4.1 of Appendix B of the ANO-1 LRA. Therefore, inspection of the most susceptible locations (e.g., pressurizer nozzles) will bound other locations that are not as susceptible to PWSCC (e.g., flowmeter element).

3.3.2.2.2.1-1 **In the final safety evaluation report (FSER) for BAW-2243A, the staff approved the ASME Section XI, examination categories B-M-1 and B-M-2 (as supplemented by the evaluation procedure described in Section 4.2 of BAW-2243A) for valves in the letdown line and the pressurizer spray line block valve fabricated from CASS. There are discrepancies between the FSER, Table 3.2-1 and Section 3.2.2 of the LRA. Describe the ANO-1 examinations for managing the aging effects for the valves in sufficient detail to allow the staff to evaluate the examinations consistent with the FSER for BAW-2243.**

As discussed in Section 3.2.2 of the ANO-1 LRA, three ANO-1 ASME Class 1 valves fabricated from CASS are susceptible to reduction of fracture toughness by thermal embrittlement: two 2½-inch valves in the letdown line and the 2½-inch pressurizer spray line block valve. These valves do not receive a surface examination in accordance with Examination Category B-M-1 since the valve bodies do not contain welded joints. In addition, there are no ASME Class 1 CASS valves at ANO-1 that are inspected in accordance with Examination Categories B-M-1 or

B-M-2 and the CASS evaluation procedure reported in BAW-2243A does not apply.

However, the saturated lower bound fracture toughness of the valve bodies is approximately equal to the fracture toughness of austenitic weldments in pipes made using the submerged arc welding process (BAW-2243A, Section 4.2). Therefore, volumetric inspections of stainless steel piping welded joints in the letdown piping or the pressurizer spray line piping, as defined by ANO-1 risk-informed ISI Program for Examination Category B-J, will bound the subject valves since valve bodies have thicker walls and lower stresses than adjacent piping.

3.3.2.2.2.1-2 **In Table 3.2-1 of the LRA, the AMPs for the letdown coolers include Section XI, Examination Category B-P, and leakage detection in reactor building. Since leakage could result in boric acid reaching the outer surface of the reactor pressure vessel causing loss of material, identify whether the boric acid corrosion prevention program is necessary for managing cracking, loss of material, and loss of mechanical closure integrity for the letdown coolers. In addition, identify whether the bolting and torquing activities program is necessary for managing the above mentioned aging effects. If the boric acid corrosion prevention and the bolting and torquing programs are not determined to be necessary for managing applicable aging effects, provide a justification for this conclusion.**

The Boric Acid Corrosion Prevention Program should be credited for managing loss of external material. Due to an administrative error, the letdown coolers were omitted from the first line of Table 3.2-1, page 3-25, where external loss of material by boric acid wastage is listed for the applicable RCS components. Loss of mechanical closure integrity is not an applicable aging effect since the heat exchangers do not include bolted closures. The connections are welded.

3.3.2.2.2.2-1 **Table 2.3-2 of the LRA contains the ANO-1 response to the renewal applicant action items identified in the staff's safety evaluation concerning BWOG report BAW-2243A. BAW-2243A addresses the reactor coolant system piping. In its safety evaluation, the staff indicated that a license renewal applicant would have to provide additional details regarding its augmented inspection program for small-bore piping. In addition, Table 2.3-4 contains the ANO-1 response to the renewal applicant action items addressed in the staff's safety evaluation concerning BAW-2244A. BAW-2244A addresses the pressurizer. An augmented inspection program for the pressurizer**

small-bore piping nozzles and safe-ends was also identified as a renewal applicant action item. The augmented inspection program addressing the action items from both topical reports is described in Appendix B, Section 4.3.8 of the LRA. For the reactor coolant system piping and the pressurizer small-bore piping nozzles and safe-ends, provide the following:

(a) The technical basis for not including lines less than 1" nominal pipe size (NPS) in the sample inspections.

ANO-1 RCS piping of 1-inch NPS is not within the scope of the risk-informed selection of piping welds for inspection since the subject piping is exempt from surface and volumetric inspection in accordance with ASME Section XI. The most risk-significant small-bore piping locations (i.e., locations with the highest susceptibility to cracking and highest consequences of failure) have been identified using a risk-informed ISI process at ANO-1, and those locations receive volumetric inspection each interval. Inspection of the most risk-significant small-bore piping locations should bound the 1-inch NPS items that are not volumetrically inspected.

Cracking at welded joints in piping less than or equal to 1-inch NPS has been addressed at ANO-1. Specifically, following the discovery of a cracked weld in an RCS drain line (1½-inch and 1-inch NPS) in 1989, ANO-1 implemented a program to investigate the potential for cracking of other similar lines. The root cause of the cracking was determined to be a weld defect that propagated by vibrational fatigue. Thermal fatigue has rarely caused piping failures. A document search covering the past 10 years at ANO-1, revealed no small-bore pipe failures that were attributed to thermal fatigue.

In the past 10 years, ANO-1 has experienced vibration induced socket weld failures on small-bore (2-inch NPS and under) vents and drains. Entergy Operations has proactively addressed these vibration problems under the site corrective action program. Comprehensive root cause analyses and corrective action plans were performed. Corrective actions included site-wide vibration awareness training, procedure improvements and development of a vibration engineering report. Several socket welds at locations of high vibration loads were reinforced. Hardware corrective actions have proven effective.

Plant changes that may introduce new vibration sources or new vents or drains are thoroughly evaluated before implementation. Furthermore, the safety-related small-bore vents and drains were thoroughly evaluated under the site corrective action program for seismic loading consideration. This effort minimized the number of non-standard (excessively long) vents and drains which might be suspectible to vibration induced fatigue failures.

Based on the above, the exclusion of 1-inch and under small-bore piping from the ANO-1 Risk-Iinformed ISI Program is justified. Aging management of cracking of small-bore Alloy 600 nozzles is addressed in Section 4.1 of Appendix B of the ANO-1 LRA.

(b) Discuss the effectiveness of volumetric examination in finding, for example, a fatigue crack; and depending on the effectiveness of the volumetric examination, identify any other examination techniques that may be used for the augmented inspections.

The ultrasonic testing (UT) method is the most common non-destructive examination (NDE) process used for volumetric examination of welds and components for in-service flaw detection, including cracking due to fatigue.

Current ANO UT procedures have been demonstrated by practical performance demonstration at the Electric Power Research Institute (EPRI) NDE Center under the Performance Demonstration Initiative (PDI). These procedures have proven capable of detecting a variety of flaws in different joint designs, diameters and thicknesses. The procedure qualifications include the detection of fatigue cracking. UT procedures are qualified for piping applications down to 2-inch NPS. Only qualified, certified UT personnel apply the procedures at ANO.

Any component or weld-joint that is not a candidate for ultrasonic examination (e.g., difficult joint design or small-bore less than 2-inch NPS) may be examined by other NDE processes. Most applications would receive a surface examination (liquid dye penetrant or magnetic particle) or a visual examination. If volumetric examination is required, usually a radiographic examination will be applied.

(c) Indicate whether small-bore Alloy 600 piping will receive a one-time volumetric examination, and provide a schedule for performing the examination.

The sample population of Alloy 600 items selected for augmented inspection is discussed in Section 4.1 of Appendix B of the ANO-1 LRA. The most susceptible location groupings include the following: (1) pressurizer sample nozzles, level tap nozzles, and thermowell nozzles, (2) pressurizer vent nozzle, and (3) the 4-inch NPS Alloy 600 safe-end that connects the pressurizer spray line to the pressurizer spray nozzle. Consistent with the ANO-1 current licensing basis, the 4-inch NPS safe-end welds are the only items that receive volumetric inspection each interval. Items in groups 1 and 2 receive augmented visual inspections from the exterior of the vessel each refueling outage.

(d) Discuss the results of previous inspections performed on the small-bore or Alloy 600 piping, nozzles and safe-ends.

Selected stainless steel welds in the 2.5-inch NPS pressurizer spray line, 2.5-inch NPS makeup and purification lines, and 2.5-inch NPS letdown line receive volumetric inspection at ANO-1 each interval in accordance with the ANO-1 risk-informed ISI plan for ASME Class 1 piping. No reportable indications have been identified from these inspections.

In 1990, on the ANO-1 pressurizer, a spare instrumentation nozzle (pressurizer level tap), MK-30, was modified due to RCS leakage. The nozzle is periodically examined utilizing a demonstrated UT technique in accordance with the ANO-1 Augmented ISI Program. The inspections found no indication of corrosion or erosion of the ferritic material. In addition, all of the Alloy 600 nozzles attached to the pressurizer have received visual inspection each refueling outage since 1990 and no indications of leakage have been observed.

In March 2000, cracks were discovered in a number of ANO-1 Alloy 600 RCS hot leg level instrumentation nozzles during a visual inspection. A root cause evaluation determined the failure mode to be cracking caused by PWSCC. The design of the nozzles resulted in high residual stresses at the root of the Alloy 82 weld that connects the Alloy 600 nozzle to the ferritic piping. The high stresses led to cracking of the welds. The Alloy 600 susceptibility model did not indicate a high susceptibility to failure since the residual stresses in the nozzles were much higher than the stresses assumed in the evaluation. A new design was developed to eliminate the residual stresses associated with welding. Repairs were made using Alloy 690, which is more resistant to PWSCC than Alloy 600.

3.3.2.3.2-1 In the FSER for BAW-2244A, "Demonstration of the Management of Aging Effects for the Pressurizer," the staff identified pressurizer components that may be susceptible to cracking. The LRA may not have considered all pressurizer components that are subject to an AMR, and may not have AMPs to manage the applicable aging effects. Determine if the following components are subject to an AMR. If so, identify the, the applicable aging effects, the AMPs for managing each aging effect; and provide a demonstration that the

effects of aging will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. If not provide a justification for excluding these component from an AMR.

- **tripod legs attached to the pressurizer vessel**
- **stainless steel nozzle forgings**
- **surge nozzle to stainless steel safe-end joint**
- **ensure that the update to Table 3.2-1 includes any changes or additions in response to this item.**

The tripod legs are attached to the pressurizer cladding and are within the scope of the pressurizer cladding examination described in Section 3.4.1 of Appendix B of the ANO-1 LRA, and Table 3.2-1, page 3-29. The pressurizer does not contain nozzles fabricated from stainless steel. The surge nozzle to stainless steel safe-end joint is within the scope of Section 3.2.3 of the ANO-1 LRA since the subject joint was within the scope of BAW-2244A. Demonstration of aging management is provided in each of the applicable aging management programs identified in Table 3.2-1 and discussed in Appendix B. No change to Table 3.2-1 is required.

3.3.2.3.2.2-1 **In the LRA for ANO-1 the applicant states that they will continue to implement the monitoring program for Alloy 600 and Alloy 82/182 locations in the ANO-1 pressurizer. In addition, the applicant indicated that the susceptibility model for ranking the Alloy 600 and Alloy 82/182 components in the pressurizer is based on the same Electric Power Research Institute (EPRI) susceptibility model that was used to rank Alloy 600 CRDM penetration nozzles in B&W designed reactor vessels. The model was described in topical report BAW-2301. This model is based on comparing the time it would take an axial crack to initiate and grow to 75% through-wall relative to the time it would take the worst case axial crack detected at D.C. Cook Unit 2 to grow to 75% through-wall. The worst case axial crack detected at D.C. Cook Unit 2 in 1994 was 43% through-wall. A more detailed description of how the cracking at D.C. Cook Unit 2 is used in the susceptibility model calculations is given in the Nuclear Energy Institute (NEI) letter to the staff dated December 11, 1998 (i.e., Letter from D. Modeen, Director of Engineering, Nuclear Generation Division, NEI, to G.C. Lainas, Acting Director of Engineering, Office of Nuclear Reactor Regulation, U.S.N.R.C.), "Responses to NRC Requests for Additional Information on Generic Letter 97-01."**

The staff has accepted the EPRI model as an acceptable approach for monitoring the Alloy 600 and Alloy 82/182 components in the PWR CRDM penetration nozzles and other vessel head penetration nozzles.

The applicant indicated that they would apply this model to the Alloy 600 and Alloy 82/182 components in the pressurizer and that the Alloy 600 reference item used for the crack initiation and growth modeling is the pressurizer instrumentation nozzle. This nozzle was determined to have a through-wall crack in 1990. With respect to how the EPRI model will predict the susceptibility of Alloy 600 and Alloy 82/182 pressurizer components to cracking:

The CRDM aging management program utilizes a computerized probabilistic model (i.e., the EPRI model) developed to assess the probability of cracking of reactor pressure vessel head penetrations. Using the EPRI model, the industry performed a cumulative probability calculation of crack growth referenced to the probability of a 75% through-wall crack existing at DC Cook at the time of its inspection in 1994. (Described in Enclosure 1 of the NEI December 11, 1998 letter from D.J. Modeen to G.C. Lainas, "Response to NRC Requests for Additional Information on Generic Letter 97-01.") In this manner, a relative ranking of all the domestic PWR units was determined (from either the EPRI model or a similar Westinghouse model) to prioritize CRDM nozzle inspections across the entire PWR nuclear industry.

The CRDM nozzle PWSCC susceptibility model, embedded in the EPRI model, calculates a reference time-to-crack initiation based on a relative time-to-10% probability of cracking for a reference CRDM nozzle (described in Enclosure 2, EPRI Model responses to Questions 1 and 2, of the same December 11, 1998 letter). The method used to rank the relative susceptibility of Alloy 600 and Alloy 82/182 items to PWSCC described in Section 4.1 of Appendix B of the ANO-1 LRA utilizes the same reference time-to-10% probability of crack initiation model, but the relevant reference item is the ANO-1 instrument nozzle, which replaces the reference CRDM nozzle in the relative time-to-10% probability of cracking calculation (refer to the discussion in Enclosure 6 of the same December 11, 1998 letter). The other software features of the EPRI program (e.g., Monte Carlo calculations) are not utilized in the Alloy 600 and Alloy 82/182 item susceptibility ranking. The method used by Entergy Operations to rank relative susceptibility of Alloy 600 and Alloy 82/182 items to PWSCC is consistent with the method approved by the NRC in NUREG-1723, Section 3.4.3.3, pages 3-110 through 3-113.

(a) **Provide further clarification about how the cracking detected in the Alloy 600 instrumentation nozzle in 1990 (the reference item for the modeling of the pressurizer components) is used to arrive at a susceptibility ranking for the remaining Alloy 600 and Alloy 82/182 components in the ANO-1 pressurizer. State whether application of the EPRI model to the Alloy 600 and Alloy 82/182**

pressurizer components requires any adjustment in the EPRI model based on the cracking of the ANO-1 pressurizer instrumentation line in 1990. Also include the basis for why it is acceptable to apply the EPRI model to the Alloy 600 and Alloy 82/182 pressurizer components.

Cracking of the Alloy 600 instrument nozzle in 1990 is used to determine the relative susceptibility of the remaining Alloy 600 and Alloy 82/182 items to PWSCC at ANO-1 by using the five-step method described in Section 4.1, "Sample Selection," of Appendix B of the ANO-1 LRA. This procedure is consistent with the method approved by the NRC in NUREG-1723, Section 3.4.3.3, pages 3-110 through 3-113.

In step 3, the ANO-1 pressurizer nozzle that leaked in 1990 was selected as the reference item for calculation of relative time-to-10% probability of crack initiation. Other Alloy 600 items (e.g., D.C. Cook CRDM penetration and Oconee Unit 2 CRDM penetration) were not considered for selection as a reference item since the operating history of the pressurizer nozzle that leaked at ANO-1 is directly relevant to ANO-1 and other BWOG Alloy 600 component items. A relative time–to-10% probability of crack initiation for the reference item was calculated by considering the service history of the ANO-1 pressurizer instrument nozzle that leaked in 1990 and the service history of the remaining Alloy 600 pressurizer instrument nozzles in service at B&W operating plants. Therefore, the relative time-to-10% probability of crack initiation calculated for the reference item considers the service history of the entire population of Alloy 600 pressurizer instrument nozzles at B&W operating plants.

Step 4 of the method requires evaluation of the differences in material and operating parameters between the reference item (i.e., ANO-1 pressurizer instrument nozzle that leaked in 1990) and the remaining Alloy 600 items and Alloy 82/182 welds at ANO-1. Using the data from Step 4, a relative time–to-10% probability of crack initiation is calculated for each Alloy 600 and Alloy 82/182 item. A relative susceptibility ranking is obtained by listing the Alloy 600 and Alloy 82/182 items in order of the calculated relative time-to-10% probability of crack initiation, i.e., from shortest relative time to longest relative time. The calculated relative time–to-10% probability of crack initiation is not used to predict a specific time at which crack initiation will begin; rather, the relative crack initiation times are used to rank a specific items susceptibility to PWSCC. Monitoring the most susceptible locations will bound the Alloy 600 items and Alloy 82/182 weld locations that are not inspected.

Application of the PWSCC susceptibility calculation from the EPRI model to the ANO-1 Alloy 600 and Alloy 82/182 items did not require any specific adjustment to the EPRI model. As described above, the only difference is use of the ANO-1 pressurizer instrument nozzle that leaked in 1990 as the reference item.

The CRDM nozzle PWSCC susceptibility model of the EPRI program is acceptable for the Alloy 600 and Alloy 82/182 items at ANO-1 since the model is similar to the CRDM Nozzle PWSCC Inspection and Repair Strategic Evaluation (CIRSE) model used to rank the susceptibility of CRDM nozzles to PWSCC at ANO-1. Use of a compatible method ensures consistency between the Alloy 600 Aging Management Program and the CRDM and Other Vessel Head penetration Inspection Program. In addition, the NRC has approved the use of the EPRI model to rank susceptibility of Alloy 600 and Alloy 82/182 items to PWSCC through the SER for the Oconee Units, as described in Section 3.4.3.3 of NUREG-1723.

(b) Using the proposed pressurizer Alloy 600 model, indicate whether any of the Alloy 600 or Alloy 82/182 components in the pressurizer are predicted to have crack growth to 75% through-wall within or before the period of extended operation. If so, provide the schedule for conducting volumetric inspections of these components.

The model described in Section 4.1 of Appendix B of the ANO-1 LRA predicts the relative susceptibility to PWSCC initiation of the Alloy 600 and Alloy 82/182 items and does not calculate the time required for crack growth to 75% through-wall.

As discussed in Section 4.1 of Appendix B of the ANO-1 LRA, the three most susceptible groups of Alloy 600 items at ANO-1 include the (1) pressurizer sample nozzles, level tap nozzles, and thermowell nozzles; (2) pressurizer vent nozzle; and (3) the 4-inch NPS Alloy-600 safe end that connects the stainless steel spray line to the stainless steel clad carbon steel spray nozzle. At present, ANO-1 conducts volumetric inspections of Alloy 600 items at selected locations in two of the three groups. The ferritic steel in the nozzle bore adjacent to the repaired Alloy 600 level sensing nozzle is periodically examined using ultrasonic testing. The pressurizer spray nozzle Alloy 600 safe end to clad carbon steel dissimilar metal welded joint is volumetrically inspected each interval. In addition, ANO-1 will continue to monitor the remaining Alloy 600 pressurizer nozzles by performing VT-2 examinations of the nozzles from the exterior of the vessel each refueling outage during the period of extended operation.

No volumetric inspections are planned for the remaining nozzles. Operating experience has shown that the cracking that may occur in these small bore nozzles leads to low levels of leakage that can be detected well before the structural integrity of the nozzle is challenged. Since the failure mode caused by the cracking has been shown not to pose a safety concern, continuation of the visual inspections will be adequate to manage the aging effect of cracking of the Alloy 600 and Alloy 82/182 pressurizer items.

3.3.2.6.1-1 **Section 2.3.1.7 of the LRA states that "Secondary piping attached to the once-through steam generator nozzles, including the main and auxiliary feedwater headers and riser piping, is addressed in Section 2.3.4.2." However, Section 2.3.4.2 does not address main and auxiliary feedwater headers and riser piping. The lack of auxiliary feedwater header and raiser discussion in Section 2.3.4.2 will be addressed in the RAIs associated with that section. However, a description of the AMRs performed for the main and auxiliary feedwater headers and riser piping is needed for the staff's review of the OTSG.**

As discussed in RAI response 2.3.1-6, the main and auxiliary feedwater header and riser piping are addressed in Section 2.3.1.7 of the ANO-1 LRA. The reference to Section 2.3.4.2 is for the secondary piping connected to the main and auxiliary feedwater headers rather than the actual headers and risers. Aging management review of the main and auxiliary header and riser piping is addressed in Section 3.2.6 and Table 3.2-1 of the ANO-1 LRA.

3.3.2.6.2.1-1 **Section 3.7 of Appendix B of the LRA describes the wall thinning inspection program. This description of the wall thinning inspection program does not address OTSGs. Identify where in the LRA is wall thinning of the OTSG addressed, or provide a justification for excluding wall thinning as an aging effect for the OTSG.**

Table 3.2-1 identifies the aging management programs applicable to the OTSG components. Loss of material is identified as an aging effect and this aging effect includes wall thinning. The aging management programs that manage this effect include the ASME Section XI ISI Program, which is discussed in Section 4.3 of Appendix B, the Chemistry Monitoring Program, which is discussed in Section 4.6 of Appendix B, and the Steam

Generator Integrity Program, which is discussed in Section 4.20 of Appendix B. The Wall Thinning Inspection Program described in Section 3.7 of Appendix B is not applicable to the OTSG.

3.3.2.6.2.1-2 **Flow of secondary fluid can cause high-frequency vibration and/or fluid elastic instability conditions of tubes and interaction with the tube support structures. Specifically, where the structural integrity of tube support plates and stabilizers are weakened due to loss of material, it may lead to tube failures. Past operating experience has indicated that this kind of fatigue failure was noted at Oconee leading to forced outages in 1994. Also, although outside-diameter stress-corrosion cracking (ODSCC) had not been identified as an active degradation mechanism in OTSGs, this should be considered as a potential effect of aging. Finally, a recent B&W owners group report, prepared by Framatome Technologies (Report No. 77-5003013-00, 2/99) on the OTSG internals, has indicated that flow-accelerated corrosion (FAC) can occur if there is a significant blockage of flow due to fouling. Identify where ODSCC and FAC related to the OTSG is discussed in the LRA, or provide a justification as to why fatigue, ODSCC, and FAC are not considered as applicable aging effects for the OTSG components.**

The license renewal rule does not require that specific aging mechanisms be discussed. Cracking of OTSG tubes may be caused by any of the specific mechanisms of fatigue, PWSCC, intergranular stress-corrosion cracking, or ODSCC. Cracking of the OTSG tubes, plugs, and sleeves is identified as an applicable aging effect in Section 3.2.6 of the ANO-1 LRA. Tube locations in the lane and wedge region that may be susceptible to high cycle fatigue have received preventive sleeving at ANO-1. The sleeving was performed to preclude future tube failures in this region of the OTSG. ODSCC has been observed in most PWR steam generators in the United States and abroad that contain Alloy 600 tubes. This mechanism has primarily been observed in recirculating steam generators at or near the tube support plates, at the top of the tubesheet, and in the freespan regions, but has not been as prevalent in OTSG tubes.

Loss of material is identified as an applicable aging effect in Section 3.2.6 of the ANO-1 LRA for the OTSG tubes, plugs and sleeves. Flow accelerated corrosion is an aging mechanism that may result in loss of material at the carbon steel tube support plates; however, the tube support plates are not subject to aging management review. The FTI report deals specifically with OTSG internals, which are fabricated from carbon steel, and there is no discussion in the FTI report that identifies loss of Alloy 600 tube material adjacent to the tube support plate due to FAC as an aging issue. In the unlikely event that FAC of the tube support plates results in loss of material of the Alloy 600 tubes due to wear in regions adjacent to the tube support plates, tube integrity would be assured through tube inspections performed in accordance with the ANO-1 Steam Generator Integrity Program.

Eddy current tube inspection methods are sufficient to detect PWSCC, ODSCC, and loss of material caused by intergranular attack. The eddy current inspection methods are qualified in accordance with the guidelines in Electric Power Research Institute, "PWR Steam Generator Examination Guidelines," EPRI TR-107569-v2r5, Revision 5, Appendix H.. No supplemental inspection techniques are required to detect ODSCC for the period of extended operation. Entergy Operations will continue to evaluate and implement new inspection techniques through compliance with the EPRI guidelines referenced in NEI 97-06, "Steam Generator Program Guidelines" which include using qualified inspection techniques for specific types of tube degradation.

The ANO-1 identified OTSG aging management programs are similar to those discussed in NUREG-1723, Section 3.4, and approved by the NRC Staff for the Oconee Nuclear Station.

3.3.2.6.2.1-3 NRC IN 94-05, "Potential Failure of Steam Generator Tubes with Kinetically Welded Sleeves" discussed cracking that occurred in steam generator tubes sleeved with kinetically (explosively) welded sleeves supplied by B&W. Identify where cracking of kinetically welded sleeves is discussed in the LRA, or provide a justification as to why cracking of these sleeves are not considered as an applicable aging effect for the OTSG.

Cracking of OTSG tubes, plugs, and sleeves is identified as an applicable aging effect in Section 3.2.6 of the ANO-1 LRA. Information Notice 94-05, "Potential Failure of Steam Generator Tubes with Kinetically Welded Sleeves," is not applicable to ANO-1 since ANO-1 does not use kinetically welded sleeves.

3.3.2.6.2.2-1 Table 3.2-1 (pages 3-34 to 3-36) of the LRA lists AMPs for components of an OTSG.

(a) Explain the type of inspection associated with the examination category B-Q of the ASME Section XI ISI-IWB applicable to tubes, plugs and sleeves.

Although 10CFR50.55a(g) imposes the inservice inspection requirements of the ASME Boiler and Pressure Vessel Code, Section XI, Examination Category B-Q, 10CFR50.55a(b)(2)(iii) confirms that the requirements of the Technical Specifications govern for steam generator tubing.

Inspection requirements for steam generator tubes, including sleeved tubes, are discussed in the ANO-1 Technical Specification Section 4.18. Tube inspection requirements usually include a minimum tube sample size and requirements for selection of tubes to be inspected. Additionally, ANO follows recommended expansion criteria in the EPRI PWR Steam Generator ISI Guidelines. It is common practice to identify and inspect tubes with previously detectable indications that are in areas of the OTSG where experience has indicated potential problems, as well as randomly sampling the rest of the tube population. The ANO-1 tube inspections are similar to the inspections discussed in NUREG-1723, Section 3.4, and approved by the NRC Staff for the Oconee Nuclear Station.

(b) Explain why the Alloy 600 AMP is not included for managing aging of secondary side nozzles made of Alloy 600, (e.g., temperature sensing nozzles/connections).

The OTSG nozzles exposed to secondary water that are fabricated from Alloy 600 are not susceptible to cracking by primary water stress corrosion cracking (PWSCC) since they are not exposed to a primary water environment.

3.3.2.6.2.2-2 The ANO-1 steam generator integrity program is structured to meet the NEI Steam Generator (SG) Program Guidelines (NEI 97-06) and the plant's technical specification 4.18. According to Table 3.2-1 of the LRA, this program mitigates the aging effects in tubes, plugs, and sleeves only. No other SG internal components whose aging effects are managed by this AMP have been identified, although the applicant has clearly indicated in the scope that this AMP applies to the SG internals in addition to SG tubes, plugs, and sleeves. Clarifications are needed in the following areas:

(a) Scope: The program includes SG internals in the AMP. Identify the SG internal components that are included in the program.

The ANO-1 Steam Generator Integrity Program, as described in Section 4.20 of Appendix B of the Application, includes the OTSG internals in accordance with NEI 97-06. OTSG internals items include tube support plates, tie rods, and internal baffles.

(b) Aging Effects: The program includes aging effects for loss of material, cracking, and fouling. Confirm whether or not these aging effects include FAC, ODSCC, and fatigue.

The aging effects of loss of material and cracking include those caused by the aging mechanisms of FAC, ODSCC, and fatigue. Please see RAI response 3.3.2.6.2.1-2.

(c) Method: Eddy current testing of tubes is mentioned. No discussion is provided on type of probes used for detecting different kinds of tube degradation. Also, eddy current testing (ECT) has been used to detect degradation of other internal components such as tube support plates (TSPs) made of carbon steel. Clarify the inspection scope and expansion criteria for the ECT used at the site. Also, indicate if these techniques are industry-qualified and are performed by qualified personnel.

The ECT methods used at ANO-1 are in accordance with ASME Section XI and Electric Power Research Institute, "PWR Steam Generator Examination Guidelines," EPRI NP-6201, Revision 5, Appendix H. The ECT inspections include a 100% full-length bobbin coil examination to identify areas of potential degradation, where it is qualified for use. For other regions of the steam generator where bobbin coil is not qualified for detection of certain degradation, such as the roll expansion in the tube sheet region and the roll expansions in the sleeve, an eddy current technique with a better probability of detection is employed (e.g., rotating pancake coil probe). Flaws that exceed the acceptance criteria contained in the technical specifications are identified as defects and the affected tube plugged or NRC-approved alternate repair criteria are employed to allow the tube to remain in service. The current inspection methods, subsequent evaluation procedures, and qualification requirements meet current licensing basis requirements and are similar to the program reviewed and approved by the NRC Staff for the Oconee Nuclear Station per NUREG-1723.

Steam generator tube inspections at ANO-1 are performed by qualified personnel in accordance with the Steam Generator Tube Surveillance Program, which is described in Section 4.20 of Appendix B of the application. Entergy Operations will continue to evaluate and implement new inspection techniques through compliance with the EPRI guidelines referenced in NEI 97-06, which include using qualified inspection techniques for specific types of tube degradation in specific regions of the OTSG. The ANO-1 Steam Generator Tube Surveillance Program complies with the steam generator program guidelines established in NEI 97-06 and is similar to the program reviewed and approved by the NRC Staff for the Oconee Nuclear Station per NUREG-1723.

3.3.2.6.2.2-3 Describe the applicable aging management activities in response to the recommended seven action items of GL 85-02 for addressing aging effects regarding SG tube integrity (e.g., FOSAR of loose parts, ISI of tubes, and water chemistry of both primary and secondary systems).

(a) Clarify how the ANO-1 SG integrity program includes recommended action items of GL 85-02.

The ANO-1 Steam Generator Tube Surveillance Program is an existing program that manages the aging of steam generator tubing in accordance with technical elements contained in NEI 97-06. The technical elements reported in NEI 97-06 are consistent with and in many cases bound the technical elements required by GL 85-02. The ANO-1 response to the recommended action items of GL 85-02 was provided to the NRC in Entergy Operations' letter 0CAN068501, dated June 14, 1985. The ANO-1 Steam Generator Integrity Program is described in Section 4.20 of Appendix B of the ANO-1 LRA and is consistent with the program reviewed and approved by the Staff for Oconee as described in NUREG-1723.

(b) Review your steam generator tube failure history and identify each applicable aging effect over the life of the plant. For each applicable aging effect, identify the AMP that will be used to manage that aging.

In addition, as described in NRC IN 97-49, "B&W Once-through Steam Generator Tube Inspection Findings," degradation has been observed in OTSGs (e.g., degradations at dented locations, the expansion transition region, freespan locations, sleeved regions, and sludge pile region). Specialized probes such as rotating probes may be required to reliably detect these indications. NRC IN-97-88, "Experiences During Recent Steam Generator Inspections," discusses the potential difficulties experienced by the applicant in qualifying and applying eddy current depth-sizing techniques. Describe the changes in the SG tube integrity program at ANO-1 to address tube degradation identified in NRC IN 97-49 and 97-88.

The ANO-1 OTSG operating history has been reviewed and applicable aging effects for the plugs, sleeves, and tubes include cracking and loss of material as discussed in ANO-1 LRA Section 3.2.6. The ANO-1 Steam Generator Tube Integrity Program is an NRC-approved program that ensures the integrity of the steam generator tubing through a defined Inservice Surveillance Program. The Inservice Surveillance Program is capable of detecting cracking and loss of material, as documented in ANO-1 reports submitted to the NRC in accordance with Section 4.18.6 of the ANO-1 Technical Specifications. This program is similar to the program used at the Oconee Nuclear Station that has been reviewed and approved by the NRC as described in NUREG-1723.

3.3.2.7.2.2-1 **In Section 3.2.7 of the LRA, the applicant stated that the aging effects applicable to seal water heat exchangers are cracking and loss of material of the inner tube, which carries the primary reactor water. The AMPs, identified by the applicant in Table 3.2-1 of the LRA, include primary water chemistry monitoring, ASME Section XI ISI, and leakage detection in reactor building. The inner tube of the heat exchangers maintains the reactor coolant pressure boundary, and the outside surface of the tube is exposed to treated water from the intermediate cooling water system. Table 3.2-1 does not reference the auxiliary system water chemistry monitoring program as one of the AMPs for the seal water heat exchangers. Describe how cracking of the outside surface of the heat exchangers inner tube is managed.**

Due to an administrative error, the Auxiliary System Water Chemistry Monitoring Program was omitted from Section 3.2.7 and Table 3.2-1 of the ANO-1 LRA. This program is credited for managing cracking of the heat exchanger tubing.

3.3.2.8.2.2-1 **The applicant identifies four AMPs for CRDM pressure boundary components. These include ASME Section X1 ISI, the leakage detection in reactor building, primary water chemistry monitoring, and bolting and torquing activities. Since leakage could result in boric acid reaching the outer surface of the reactor pressure vessel and could cause loss of material, identify whether the boric acid corrosion prevention program is necessary for managing the loss of material for the CRDM pressure boundary components. If not, provide a justification for excluding loss of material due to boric acid corrosion as an aging effect for the CRDMs.**

The CRDM pressure boundary items exposed to the external environment are stainless steel or low-alloy steel with external nickel plating (i.e., center section of Type B Drive only at ANO-1). Stainless steel and nickel are resistant to boric acid wastage and loss of material by boric acid wastage is not an applicable aging effect for these items. Loss of external material by boric acid wastage is an applicable aging effect for all ferritic reactor vessel items.

3.3.2.8.2.2-2 The CRDM motor tube housings provide the reactor coolant pressure boundary for the CRDMs during service. The housings, which are made from stainless steel or Alloy 82/182 clad low-alloy steel, are filled with borated water during service. Possible PWSCC and fatigue failure of the housings is managed by the applicant through the primary water chemistry monitoring program. However, the coolant in the housing is relatively stagnant and its local chemistry may not be effectively controlled by the primary water chemistry system. Identify whether there are any locations in the CRDM pressure boundary system where the water chemistry may not meet acceptance criteria because of accumulation of contaminants and radiolytic oxygen. One such instance, is described in Palisades inspection report 50-255/99012 (DRP). Cracks were observed in the vicinity of the "J" welds which attach the seal housing tube to the autoclave flange. If such area of contaminant accumulation exist, discuss whether aging management of the affected components is necessary, and whether any programs are in place to detect or to mitigate the aging effects. If not, provide a justification for excluding cracking due to contaminant accumulation as an applicable aging effect for the CRDM motor tube housings.

The internal environment assumed in the aging evaluation of the CRDM items is borated water with chlorides, fluorides, and oxygen (when at elevated temperature) maintained within prescribed limits to eliminate stress corrosion cracking caused by high levels of these contaminants. ANO-1 has a Primary Water Chemistry Monitoring Program that contains adequate controls to support the conclusion that elevated levels of chlorides, fluorides and sulfates do not exist in the control rod drive mechanisms. The ANO-1 sampling specifically verifies the chlorides, fluorides, and sulfates are less than 150 ppb. Chlorides, fluorides, and sulfates are typically maintained less than 50 ppb.

At ANO-1, the CRDMs are filled with high boron/low lithium (low pH) water that contains oxygen, up to approximately 8 ppm at temperatures less than 150°F. The CRDMs are vented while the plant is less than 200°F. Under these conditions, the CRDM materials are resistant to crevice corrosion, pitting corrosion, and stress corrosion cracking since impurities (halogens and sulfates) are maintained at minimal levels (e.g., in accordance with the EPRI primary water chemistry guidelines).

Oxygen is not expected to remain in the CRDMs for an extended period since the surfaces of CRDM materials in contact with the water will quickly scavenge the residual dissolved oxygen. At elevated temperatures, the RCS is maintained with a low oxygen level, therefore, oxygen will only be introduced to the CRDMs during the initial fill. Inspections of the CRDM internals support the conclusion that oxygen is not present in these assemblies during power operation. Loss of material by corrosion and pitting, and SCC of CRDM pressure boundary items have not been observed at ANO-1 in visual inspections of drives during routine and corrective maintenance activities. In addition, inspections at other B&W operating plants have found no indications in the motor tube extensions. While contaminant accumulation is not expected, cracking, if it does occur will be managed by Section XI ISI activities.

4.3.3-1 **Section 4, Table 4.1-1, of the LRA lists the components that have time-limited aging analyses (TLAAs). The table indicates that the TLAAs associated with fatigue and flaw growth are addressed in Section 4.3 of the LRA. However, Section 4.3 of the LRA does not contain a specific reference to the steam generators. Indicate how each TLAA listed in Table 4.1-1 for the steam generators is addressed.**

Section 4.3.2 of the ANO-1 LRA discusses the B&W scope of supply (i.e., vessels and piping). The B&W scope of supply includes the once through steam generators. The metal fatigue evaluations were performed during the design of the components. Those evaluations are expected to remain valid for the duration of the period of extended operation. These evaluations are available for review. As discussed in Section 4.3.4 of the ANO-1 LRA, the ANO-1 Transient Cycle Logging Program, discussed in Section 4.3.5 of the ANO-1 LRA, will ensure that each TLAA for the steam generators is addressed in accordance with 10CFR54.21(c)(1)(i).

4.3.3-2 **Section 4.3.3.4 of the LRA contains a discussion of environmentally assisted fatigue. The discussion indicates that an effective approach to manage this issue is to identify the locations that are most susceptible to failure from thermal fatigue and include these locations in the augmented inservice inspection program. The application references the six locations listed in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The application further indicates that three locations have been evaluated in BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel." Provide the following information for the remaining three locations: the pressurizer surge line, the makeup/HPI nozzles, and the decay heat removal Class 1 piping:**

(a) An assessment of the potential for fatigue cracking of these locations considering the assessment of the environmental fatigue data presented in NUREG/CR-5704, "Effects of LWR Coolant

Environment on Fatigue Design Curves of Austenitic Stainless Steels."

The response to this item is based on a review of the results from NUREG/CR-6260 and the adjusted fatigue design data for stainless steels in NUREG/CR-5704. As a part of the effort to close Generic Safety Issue (GSI)-166 (later GSI-190) for operating nuclear power plants during the current 40-year license term, Idaho National Engineering and Environmental Laboratory (INEEL) evaluated fatigue-sensitive component locations at plants designed by the four U.S. nuclear steam supply system vendors. NUREG/CR-6260 provides the results of those evaluations. The PWR calculations and, in particular, the Babcock and Wilcox PWR calculations, are directly relevant to ANO-1.

More recent test data have been generated by Argonne National Laboratory. The updated analytical expressions for the mean fatigue initiation life of austenitic stainless steel in both air and the laboratory-simulated light water reactor (LWR) environment were published in NUREG/CR-5704. An assessment of the potential for fatigue cracking of the pressurizer surge line, the makeup/high pressure injection (HPI) nozzles, and the decay heat removal ASME Class 1 piping has been conducted using the method and environmental fatigue data provided in NUREG/CR-5704.

- For the surge line, cumulative usage factors (CUFs) may exceed 1.0 at selected locations during the period of extended operation. A more refined and labor intensive analysis, if performed, would be expected to reduce the CUFs to less than 1.0 at many of these locations.

- For the HPI/makeup nozzles and safe-ends, CUFs may exceed 1.0 at selected locations during the period of extended operation. This result is based on consideration of the existing usage factors and the applicable environmental effect penalty factors for carbon steel and stainless steel.

- For the decay heat removal piping, usage factors were recalculated using the 1986 ASME Code rules as suggested in NUREG/CR-6260. For these locations, the CUFs at the end of a 60-year life were less than 1.0.

Due to the factor of safety included in the ASME Code, a CUF of greater than 1.0 does not indicate that fatigue cracking is expected. However, there is some potential for fatigue cracking to occur during the period of extended operation at locations having CUFs exceeding 1.0.

(b) A discussion of the augmented inservice inspection program planned for these locations. This discussion should address the specific areas of the components that will be inspected, the method used to qualify the inspections for areas not adjacent to weld joints, and the frequency of the inspections given the assessment performed for item (1).

Prior to entering the period of extended operation, for each surge line and HPI nozzle and safe-end location that may exceed a CUF of 1.0 when considering environmental effects, an approach will be developed to show that the effects of fatigue can be managed. The approach for addressing fatigue will include one or more of the following:

1. Further refinement of the fatigue analysis to lower the CUFs to below 1.0, or
2. Repair of the affected locations, or
3. Replacement of the affected locations, or
4. Manage the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

Should Entergy Operations select Option 4 (i.e., inspection) to manage environmentally-assisted fatigue during the period of extended operation, inspection details such as scope, qualification, method, and frequency will be provided to the NRC prior to entering the period of extended operation.

(c) Describe how the augmented inspections satisfy the applicable requirements of 10CFR Part 54.21 with regard to demonstrating that the effects of thermal fatigue for these three locations will be adequately managed so that the intended function(s) will be maintained for the period of extended operation.

As described in response to item (b) above, Entergy Operations will select one of four options to address environmentally-assisted fatigue for pressurizer surge line and HPI nozzles and safe-end locations that exceed a CUF of 1.0 during the period of extended operation. If augmented inspections are selected, the inspections are expected to be able to detect cracking due to thermal fatigue prior to loss of function. If cracking is detected, replacement or repair will then be implemented such that the intended function will be maintained for the period of extended operation

4.3.3-3 **Section 4.3.4.4 of the LRA describes actions taken in response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The application indicates that stratified flows were identified in lines that were monitored at ANO-2. The application indicates that, because of the ANO-2 experience, further monitoring and evaluation of four ANO-1 lines was performed. The application further indicates that temperature monitoring and evaluations have demonstrated that the ANO-1 lines are qualified for their service conditions. Describe in more detail the measurements, calculations, and criteria that led to the conclusion that the four ANO-1 lines are qualified for their service conditions.**

In accordance with current licensing basis, Entergy Operations has resolved the thermal stratification issue identified in NRC Bulletin 88-08 using screening and acceptance criteria provided in the bulletin. The applicable ANO-1 lines have been screened, monitored, inspected, evaluated, or physically modified in order to meet the acceptance criteria in NRC Bulletin 88-08. Commitments regarding inspections at ANO-1 in response to NRC Bulletin 88-08 have been superseded by the ANO-1 risk-informed inspection of ASME Class 1 piping. Please see the RAI response 4.3.3-4 for a reference to the NRC SER for the ANO-1 risk-informed inspection for piping. Aging effects due to thermal stratification as described in Bulletin 88-08 will be managed by maintaining associated thermal fatigue calculations and augmented inspection program (as part of RI-ISI) through the period of extended operation.

4.3.3-4 **As discussed in Section 4.3.4.4 of the LRA, the applicant committed to perform enhanced ultrasonic examination of 17 high-pressure injection (HPI) welds and two segments of HPI piping as part of the ANO-1 ten year interval ISI plan in response to 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The LRA further indicates that the scope of the HPI ISI inspections was subsequently modified as a result of the implementation of ASME Code Case N-560, "Alternate Examination Requirements in Class 1, Category B-J Piping welds Section XI, Division 1." Describe the modifications to the scope of the enhanced ultrasonic ISI examination of 17 HPI welds and two sections of HPI piping that were made as a result of the implementation of Code Case N-560 at ANO-1.**

The LRA discussion regarding NRC Bulletin 88-08 concludes: "This issue has therefore been resolved for the period of extended operation." The intent of this statement in the LRA is not clear to the staff. Specify precisely what issue was resolved for the period of extended operation. Also, describe how the ANO-1 inspections of the HPI piping and welds meet the applicable requirements of 10CFR54.21 with regard to demonstrating that the effects of thermal fatigue of the HPI piping will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of operation.

The HPI piping system risk-informed inspection program implemented per Code Case N-560 supersedes the ANO-1 commitment to NRC Bulletin 88-08. The original ANO-1 commitment to Bulletin 88-08 required NDE (i.e., volumetric examination) at 16 locations (due to an administrative error, 17 were reported in the ANO-1 LRA) and visual inspection of two piping segments. Based on the results of the risk-informed review of makeup/HPI piping segments, eight of the original 16 locations and five new locations were selected for volumetric inspection. Therefore, the total population of volumetric inspections has been reduced from 16 to 13 welds based on consideration of risk (i.e., probability and consequences of failure). In addition, the visual inspections of the two segments of HPI piping were discontinued with the implementation of the risk-informed ISI program.

A full description of the impact of the RI-ISI application on augmented inspection programs at ANO-1, including NRC Bulletin 88-08, is provided in the response to question 18 of the letter to the NRC "Additional Information in Support of Risk-Informed Inservice Inspection Pilot Application," dated May 17, 1999 (1CAN059902). In that letter, it was conveyed to the NRC that the previous 88-08 augmented inspection program at ANO-1 was subsumed by the RI-ISI process. The NRC issued a safety evaluation approving the RI-ISI application at ANO-1 in "Risk-Informed Alternative to Certain Requirements of ASME Code Section XI, Table IWB-2500-1 at Arkansas Nuclear One, Unit 1", dated August 25, 1999 (1CAN089904).

The statement "This issue has therefore been resolved for the period of extended operation," reflects the Entergy Operations' position and the Staff's SER that the risk-informed ISI program is adequate to manage cracking caused by thermal fatigue as described in Bulletin 88-08. Consistent with the current licensing basis, the risk-informed ISI program meets the requirements of 10CFR54.21(c)(1)(iii). The risk-informed ISI program will be maintained through the period of extended operation.

4.3.3-5 **As discussed in Section 4.3.4.4 of the LRA, the applicant originally committed to performing enhanced ultrasonic examination of two elbows of the surge line as part of an ANO-1 ten year interval ISI plan in response to 88-11, "Pressurizer Surge Line Thermal Stratification." Subsequently, the scope of the ISI was changed based on an ANO-1 risk analysis performed consistent with the requirements of ASME Code Case N-560, "Alternate Examination Requirements in Class 1, Category B-J Piping welds Section XI, Division 1." Describe the modifications to the scope of the enhanced ultrasonic ISI examination of the two surge line elbows that were made as a result of the implementation of Code Case N-560 at ANO-1.**

The LRA discussion regarding NRC Bulletin 88-11 concludes: "This issue has therefore been resolved for the period of extended operation." The intent of this statement in the LRA is not clear to the staff. Specify precisely what issue was resolved for the period of extended operation. Also, describe how the ANO-1 inspections of the surge line meet the applicable requirements of 10CFR54.21 with regard to demonstrating that the effects of thermal fatigue of the surge line piping will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of operation.

The scope of the enhanced ultrasonic ISI examination of the two surge line elbows was not changed as a result of the implementation of Code Case N-560 at ANO-1. The base metal examinations of the two surge line elbows originally identified for inspection in response to Bulletin 88-11 are included in the RI-ISI program (see letter to NRC, "Additional Information in Support of Risk-Informed Inservice Inspection Pilot Application," dated May 17, 1999 (1CAN059902)). Thus, there was no modification of the 88-11 commitment with respect to the subject elbows in implementing the risk-informed inservice inspection program.

The statement "This issue has therefore been resolved for the period of extended operation" reflects the Entergy Operations' position that cracking of the pressurizer surge line due to thermal stratification will be managed by the inspections in accordance with the NRC-approved ANO-1 RI-ISI program through the period of extended operation.

4.3.3-6 **Section 4.3.3.4 of the LRA contains a discussion of HPI/MU Nozzle cracking at B&W plants. The LRA indicates that, in order to manage cracking effects in the HPI/MU nozzle, ultrasonic testing of the knuckle region of the HPI nozzles will be performed every fifth**

refueling cycle, and that radiography of the thermal sleeves will continue through the period of extended operation. The scope and frequency of radiographic testing was not specified in the application. Provide the scope and frequency of the thermal sleeve radiography proposed for the period of extended operation.

Under the ANO-1 augmented ISI program, radiographic testing of the accessible welds is performed on each of the four HPI lines, i.e. safe-end to pipe and the safe-end to nozzle welds. The radiographic testing is also used to monitor the gap between the safe-ends and thermal sleeves. Radiographic testing is performed every fifth refueling outage.

4.7-1 **The LRA, Section 4.7, describes the TLAA for the degradation of Boraflex, which is currently used in Region I of the ANO-1 spent fuel storage racks as a neutron absorber. In response to GL 96-04, you committed to continued monitoring and analysis of the Boraflex degradation at ANO-1. The LRA, Section 4.7, states that the existing coupon monitoring program will be continued, as required, into the extended license period. In addition, monitoring of the spent fuel pool silica levels and perform silica evaluations will also be continued into the period of extended operation. These evaluations are based on the EPRI RACKLIFE system or its equivalent. Projected Boraflex performance will be assessed to confirm that a 5% subcriticality margin will be maintained as required.**

Your response to GL 96-04 states that long term and accelerated test location coupon specimens are periodically removed and inspected and that "the inspections provide an indication of the general condition of the Boraflex, including gross or unusual degradation." Long term coupons are tested approximately every five years, while accelerated coupons are tested after each refueling. In addition, monitoring of the spent fuel pool silica levels, silica evaluations based on the EPRI RACKLIFE system or its equivalent, and assessment of the projected Boraflex performance to confirm a 5 percent subcriticality margin will continue through the next evaluation period. These assessments will be performed each cycle prior to fuel receipt.

In order to complete the evaluation of this TLAA, the staff requests the following information:

(a) Clarify that the frequency of the inspection and testing as discussed above will be the same for the extended license period.

(b) Are there sufficient long-term and accelerated coupons to continue the existing monitoring program through the end of the extended license period? If not, by what other means will indications of actual Boraflex degradation be obtained?

(c) Describe the physical conditions that are observed during the inspection of the sampling coupons. Do they include inspections for discoloration, hardness and reduction of thickness? If not, what conditions are observed that are directly related to the degradation of the Boraflex?

(d) Boraflex panel degradation can be characterized by gap formation and a decrease in areal boron density. Clarify how these parameters are monitored by the ANO-1 program. If not, provide the technical bases for not monitoring these parameters.

(e) Provide the results of current trending analyses that have been obtained by use of the RACKLIFE code. Do these results demonstrate that the 5% subcriticality margin of the spent fuel racks will be maintained for the extended period of operation? If not, describe the corrective actions that will be implemented to ensure that the 5 percent subcriticality margin will be maintained through the extended period of operation.

Items (a) through (e) are being addressed concurrently as follows. Since the submittal of the ANO-1 LRA, Boraflex monitoring has revealed that the Boraflex is degrading more rapidly than expected. This condition has been documented in accordance with the onsite Appendix B corrective action program and is currently being evaluated in order to determine the appropriate action. It has been determined that the Boraflex, as incorporated in the initial spent fuel pool rack design, will not last through the current 40-year licensing term, and therefore, should no longer be considered a TLAA with respect to license renewal. As a part of the ANO corrective action process, several options are currently being evaluated. They include a revised criticality analysis, modification to the existing spent fuel pool racks with a different neutron absorber, or a combination thereof. Due to the current rate of Boraflex degradation, Entergy Operations plans to complete the evaluation and identify a corrective action plan for the remainder of a 60-year operating term by the fourth quarter of 2002. Since the current ANO-1 Technical Specification for the spent fuel pool racks is based on Boraflex being present, our corrective action will include a submittal of a license amendment in accordance with 10CFR50.90.

Entergy Operations is currently scheduled to complete the ANO-1 license renewal process by January 2002. Therefore, the final resolution to this concern for the entire term of the operating license at the time of submittal will be subject to NRC review and approval under Section 90 of 10CFR Part 50.

4.8.2.3-1 **Section 4.8.2 of the LRA indicates that flow induced vibrations of the reactor vessel incore instrumentation nozzles was identified as an additional TLAA for ANO-1 that had not been identified in BAW-2251. The application indicates that BAW-10051, "Flow Induced Vibration Endurance Limit Assumptions," contains a comparison of the calculated stress values for the incore instrumentation nozzles to the endurance limit (stress values). The endurance limit values for the current licensing basis of 40 years used an assumption of 10^{12} cycles. The application indicates that, after the number of cycles was increased to that expected after 60 years of operation, and the component stress levels were compared to the recalculated endurance limit, the stress levels are acceptable. Provide the basis for the new fatigue endurance limit. Also, provide the comparison of component stress level and the recalculated endurance limit for the expected number of fatigue cycles for 60 years of operation.**

The endurance limit used in the flow-induced vibration TLAA assessment was obtained from the Appendices of the 1986 Edition of ASME Section III, Division 1. Specifically, Curves A, B, and C reported in Figure I-9.2.2 of the ASME III, Division 1, extend to 10^{11} cycles, with stress values listed in Table I-9.2.2. Curve C was not considered since it only applies to primary plus secondary stress ranges higher than 27,000 psi and the highest peak stress range for the reactor vessel internals is 23,000 psi (see BAW-10051, Table 5.1). Therefore, Curve B was selected for the evaluation of items fabricated from austenitic stainless steel.

The number of cycles assumed for 60-years of operation was conservatively estimated to be 10^{13} cycles, which is 10 times the value estimated for 40 years of operation (i.e., 10^{12}). Since Figure I-9.2.2 extends to 10^{11} cycles, the fatigue curve was extrapolated to 10^{13} cycles by assuming a 4% reduction per decade, which is consistent with the assumption in BAW-10051, Appendix A. In addition, a multiplication factor of 0.9 is considered for thermal adjustment of the fatigue curves to account for temperature effects (i.e., Young's modulus at operating temperature is approximately 10% lower than at room temperature).

Therefore, the endurance limit for reactor vessel internals items fabricated from austenitic stainless steel at 10^{13} cycles was conservatively estimated to be 13,700 psi [16,500 psi at 10^{11} cycles*$(0.96)^2$ for two decades*(0.9) for thermal adjustment due to changes in Young's modulus=13,700 psi].

The endurance limit for high strength bolting at 10^{13} cycles was conservatively estimated to be 9,100 psi by using Table I-9.4 of ASME Section III with maximum nominal stress less than or equal to 2.7*Sm [13,500 psi at 10^6 cycles*$(0.96)^7$ for 7 decades*(0.9) for thermal adjustment due to changes in Young's modulus=9,100 psi].

The maximum alternating stresses for reactor vessel internals items (bolting and non-bolting) are reported in Table 5.1 of BAW-10051. The alternating stress values reported in Table 5.1 are less than (by at least 19%) the 10^{13} cycle endurance limits reported above for austenitic stainless steel and high strength bolting. Therefore, the reactor vessel internals are acceptable for the period of extended operation when considering flow-induced vibration loading.

4.8.3.3-1 **In Section 4.8.3, NUREG/CR-6177 is cited as providing information relevant to the leak-before-break (LBB) reassessment of the CASS RCP inlet and exit nozzles in the area of the welded joint to the austenitic stainless steel 28-inch transition piece. Confirm that the δ-ferrite level of the CASS RCP (made from statically-cast CF8M) nozzles is within the bounds of applicability for the NUREG/CR-6177 correlations. If not, explain why the information in NUREG/CR-6177 applies to your material, or provide other information which supports your analysis.**

The maximum δ-ferrite content of the ANO-1 CASS RCP nozzles is 14.2% (using Hull's equivalent factors), which is within the bounds of the correlations reported in NUREG/CR-6177.