3. AGING MANAGEMENT REVIEW RESULTS

3.0 Common Aging Management Programs

3.0.1 Introduction

This section of the SER contains the staff's evaluation of 18 AMPs that are in Appendix B of the LRA, and are referenced as a part of the AMR for two or more of the systems and/or structures. It should be noted that the staff's conclusions on the evaluations of these 18 common AMPs may be predicated on the assumption that they are implemented in conjunction with other AMPs (if more than one AMP is credited by the applicant) as discussed in subsequent sections of this SER for managing the effects of aging of SCs that are subject to an AMR.

3.0.2 Program and Activity Attributes

The staff's evaluation of the applicant's AMPs focuses on program elements, rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation, the staff used 10 elements to evaluate each program and activity. The 10 elements of an effective AMP were developed as part of NUREG 1800, "Standard Review Plan for License Renewal," which was issued in July 2001. This SER describes the extent to which the 10 elements are applicable to a particular program or activity, and evaluates each program and activity against those elements that are determined to be applicable. On the basis of NRC experience with maintenance programs and activities, the staff concluded that conformance with the 10 elements of an AMP, or a combination of AMPs, provides reasonable assurance that an AMP (or combination of programs and activities) is demonstrably effective at managing an applicable aging effect. The following 10 elements of an effective AMP will be considered in evaluating each AMP used by the applicant to manage the applicable aging effects identified within this SER:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. corrective actions
8. confirmation process
9. administrative controls
10. operating experience

In the LRA, Appendix B, Section B.2.2, "Attribute Definitions," the applicant described the elements involving corrective actions and confirmation processes for license renewal. The staff notes that Selected Licensee Commitments (SLCs) are part of the UFSARs for McGuire and Catawba and, therefore, are controlled documents that delineate regulatory requirements. The staff's evaluation of the applicant's corrective action program was evaluated generically and is discussed separately in Section 3.0.4 of this SER.

3.0.3 Common Aging Management Programs and Activities

3.0.3.1 Borated Water Systems Stainless Steel Inspection

The applicant described its Borated Water Systems Stainless Steel Inspection program in Section B.3.4 of LRA Appendix B. This program is credited with managing the potential aging effects of loss of material and cracking due to exposure to alternate wetting and drying in borated water environments. The staff reviewed Section B.3.4 of LRA Appendix B to determine whether the applicant has demonstrated that borated water systems stainless steel inspection activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.1.1 Technical Information in the Application

Section B.3.4 of LRA Appendix B describes the Borated Water Systems Stainless Steel Inspection as a way of characterizing any loss of material or cracking of stainless steel components exposed to alternate wetting and drying in borated water environments. The purpose of the program is to determine if alternate wetting and drying of components in the containment spray and refueling water systems is causing aging in stainless steel components such that they may lose their pressure boundary function. It is described as a one-time inspection of stainless steel components, welds, and heat-affected zones, as applicable, in the containment spray system in the area of the internal air/water interface. The location to be inspected is stagnant and isolated from the rest of the containment spray system; therefore, it is not controlled by the Chemistry Control Program. As the water evaporates, contaminants could concentrate and lead to loss of material or cracking.

3.0.3.1.2 Staff Evaluation

The staff's evaluation of the Borated Water Systems Stainless Steel Inspection activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant defined the scope of the Borated Water Systems Stainless Steel Inspection program as including the stainless steel components exposed to an alternate wetting and drying borated water environment in the following McGuire and Catawba systems:

- containment spray
- refueling water

The staff finds the scope of the program to be acceptable and appropriate to determine if alternate wetting and drying of components will result in aging effects.

[Preventive or Mitigative Actions] There are no preventive actions taken as part of this inspection, and the staff did not identify the need for any preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the Borated Water Systems Stainless Steel Inspection program is pipe wall thickness, as a measure of loss of material or cracking of stainless steel components, at 1 of 12 possible locations at each site. The staff noted that stainless steel has demonstrated susceptibility to intergranular stress corrosion cracking in low-temperature borated water systems in PWRs, particularly in stagnant lines, at weld heat-affected zones (HAZ), involving weld procedures that resulted in sensitization of the stainless steel in the HAZ. The staff noted that not all welds, stress patterns, impurity levels, and species of steel are necessarily similar.

By letter dated January 28, 2002, the staff requested, in RAI B.3.4-1, the applicant to justify why inspection of only 1 of 12 locations adequately represents the durability of material at the other 11 locations, and to explain the process for inspection population expansion should aging effects be identified. In its response dated March 15, 2002, the applicant responded that a search of operating experience did not reveal any instances of failure of stainless steel components exposed to an alternate wetting and drying in a borated water environment, so there is uncertainty as to whether degradation will occur. The applicant intends to evaluate all possible locations and select the one that would most likely result in the identification of loss of material or cracking if they were occurring. Criteria such as geometry, proximity to hot equipment, and operating experience will be used to select the locations for inspection. Any inspection population expansion would be driven by the corrective action process if either loss of material or cracking is found.

By letter dated January 28, 2002, the staff also requested, in RAI B.3.4-2, the applicant to describe the criteria for (1) assessing the severity of any observed degradation, and (2) determining whether or not corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. In RAI B.3.4-3, the staff asked if the inspections will be looking for evidence of pitting, and if so, asked the applicant to discuss the inspection techniques that will be used to reliably identify the presence of pits. In its response dated March 15, 2002, the applicant stated that the volumetric methods to be used in the inspections will detect loss of material, including evidence of pitting. The presence of a few pits would not be a structural concern that could lead to loss of component function, and heavy pitting would be revealed as general wall loss by volumetric examination techniques.

The staff finds the information provided in the LRA and the applicant's responses to these RAIs reasonable and acceptable because the applicant proposes to adequately monitor the conditions that relate to the aging effects of concern.

[Detection of Aging Effects] The applicant indicated that this AMP is a one-time inspection that will detect the presence and extent of loss of material or cracking of stainless steel components. In RAI B.3.4-1, the staff requested the applicant to justify why a one-time inspection was adequate, given the susceptibility of stainless steel to intergranular stress corrosion cracking in certain environments. In its response, the applicant stated that engineering judgment would be applied to determine if corrective actions, including an increase in the inspection population, are warranted based on the result of the inspection.

Based on the staff's review of the LRA, the applicant's responses to the staff's RAIs, and the applicant's commitments to perform this one-time inspection and make modifications as needed based on industry operating experience or other evaluations, the staff finds that the monitoring is appropriate for the scope of this inspection. The staff concurs that trending is not required.

Based on information provided in the LRA and the responses to the RAIs described above, the staff concludes that this one-time inspection is capable of detecting the presence and extent of loss of material or cracking of stainless steel components within the scope of the program prior to loss of component function.

[Monitoring and Trending] As described in Section B.3.4 of LRA Appendix B, the Borated Water Systems Stainless Steel Inspection program will inspect stainless steel components, welds, and heat-affected zones, as applicable, in the containment spray system in the area of the internal air/water interface. The applicant identified the containment spray system as the most susceptible to degradation from this environment. The borated water environment found downstream of selected valves in the containment spray system is stagnant and isolated from the remainder of the system, and therefore, not controlled by the Chemistry Control Program. During valve testing, water from the refueling water storage tank is introduced in the pipe, with the level in the piping reaching the same elevation as the tank. Since the pipe is open to containment, evaporation occurs and concentration of contaminants could occur at the air/water interface. This concentration of contaminants could lead to loss of material or cracking.

The applicant will inspect 1 of 12 possible locations at each site using volumetric technique. If no parameters are known that would distinguish the susceptible locations at each site, 1 of the 12 available at each site will be examined based on accessibility and radiological concerns. The applicant will apply the results of this inspection to the specific stainless steel components exposed to an alternate wetting and drying borated water environment in the refueling water system. No actions are taken as part of this activity to trend inspection results. Should industry data or other evaluations indicate that the above inspections can be modified or eliminated, the applicant will provide plant-specific justification to demonstrate the basis for the modification or elimination.

Based on the staff's review of the LRA, the applicant's responses to RAIs 3.4-1 and 3.4-2, and the applicant's commitments to perform this one-time inspection and make modifications as needed based on industry operating experience or other evaluations, the staff finds that the monitoring is appropriate for the scope or this inspection. The staff concurs that trending is not required.

[Acceptance Criteria] The applicant described the acceptance criteria for the Borated Water Systems Stainless Steel Inspection as no unacceptable loss of material or cracking that could result in a loss of the component intended function, as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.4-2, the applicant to provide its criteria for assessing the severity of the observed degradation, and for determining whether or not corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Because the inspection techniques are capable of detecting degradation of concern, the staff finds the applicant's response reasonable and acceptable.

[Operating Experience] The LRA describes this as a one-time inspection for which there is no operating experience. However, volumetric examination techniques have been effective in detecting loss of material or cracking in stainless steel components. The staff finds this reasonable and acceptable.

3.0.3.1.3 FSAR Supplement

In Appendix A-1, Section 18.2.2, and Appendix A-2, Section 18.2.2, of the LRA, the applicant provided proposed new UFSAR sections for McGuire and Catawba, respectively. The staff reviewed this material and found it to be consistent with the material provided in LRA and, therefore, acceptable.

3.0.3.1.4 Conclusion

The staff has reviewed the information provided in Section B.3.4 of LRA Appendix B the summary description of the Borated Water Systems Stainless Steel Inspection program in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's RAIs. On the basis of the above evaluation, the staff finds that the Borated Water Systems Stainless Steel Inspection program will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.2 Chemistry Control Program

The applicant described its Chemistry Control Program in Section 3.6 of LRA Appendix B. The staff reviewed the application to determine whether the applicant has demonstrated that the Chemistry Control Program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.2.1 Technical Information in the Application

The Chemistry Control Program applies to the systems containing four different chemical environments: borated water, closed cooling water, treated water, and fuel oil. The major systems containing these environments are listed in the table below. The table also contains the industry guidelines and standards used to develop the corresponding aging management procedures.

Chemical Environment	Major Systems	Industry Guidelines, Codes, or Standards
Borated Water	Reactor Coolant Refueling Water Spent Fuel Pool Cooling	EPRI Report TR-105714-R4 "PER Primary Water Chemistry Guidelines"
Closed Cooling Water	Component Cooling System Recirculated Cooling Water System	EPRI Report TR-107396 "Closed Cooling Water Chemistry Guidelines"
Treated Water	Demineralized Water Feedwater SG Wet Lay-up Recirculation	EPRI Report TR-102134-R5 "PER Secondary Water Chemistry Guidelines"
Fuel Oil	Diesel Generator Fuel Oil Standby Shutdown Diesel	ASTM Standards

This program manages the relevant conditions that lead to the onset and propagation of loss of material and cracking which could lead to a loss of structure or component intended functions. Relevant conditions are specific parameters such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations that could lead to loss of material and/or cracking if not properly controlled. The applicant concluded that the Chemistry Control Program will manage loss of material and/or cracking of components exposed to borated water, closed cooling water, fuel oil, and treated water environments.

3.0.3.2.2 Staff Evaluation

The staff's evaluation of the Chemistry Control Program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER.

After completing its initial review, the staff identified several areas where additional information was needed. The LRA did not classify fouling of the heat exchangers in several systems as an aging effect. The applicant did not specify how the procedures in the site program manuals and the parameters monitored for each of the three chemistries deviated from the EPRI chemistry guidelines. The applicant also did not specify the acceptance criteria for fuel oil. By letter dated January 28, 2002, the staff issued RAIs B.3.6-1, B.3.6-2, B.3.6-3, and B.3.6-4 to obtain clarification from the applicant. By letter dated March 15, 2002, the applicant responded to the staff's RAIs. It modified the plant's UFSAR by including fouling to the mechanisms which could lead to a loss of structure or component intended function. The applicant indicated that the deviations from the EPRI guidelines were included in the plant procedures with proper technical documentation to justify them. The applicant also referenced the appropriate sections of the TS bases for Catawba and McGuire containing the descriptions of the standards used in developing the acceptance criteria for fuel oil.

This program manages specific parameters such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations that lead to the onset and propagation of loss of material and cracking if not properly controlled. The Chemistry Control Program manages the aging effects caused by loss of material, cracking, and fouling in the components exposed to the four different chemical environments specified in the table above. Except for the program scope, the other evaluations of the Chemistry Control Program apply to both Catawba and McGuire.

The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The scope of the program consists of managing aging effects of the components located in the systems containing four chemical environments: borated water, closed cooling water, treated water, and fuel oil. Monitoring and controlling these environments will ensure that aging effects for the affected components will be properly managed.

For the borated water environment, the Chemistry Control Program manages aging effects of the components in the following systems:

In Catawba and McGuire —
- boron recycle
- chemical and volume control
- containment spray
- nuclear sampling
- residual heat removal
- safety injection

In Catawba only —
- equipment decontamination

For the closed cooling water environment, the Chemistry Control Program manages aging effects of the components in the following systems:

In Catawba and McGuire —
- building heating water or heating water
- component cooling
- control area chilled water
- diesel generator cooling water
- ice condenser refrigeration
- standby cooling shutdown diesel

In Catawba only —
- auxiliary ventilation
- recirculated cooling water

In addition, control of the closed cooling water environment manages aging effects of the heat exchangers in the following systems:

In Catawba and McGuire —
- chemical and volume control
- control area ventilation or control room area ventilation
- diesel generator lube oil
- residual heat removal
- waste gas

For the treated water environment, the Chemistry Control Program manages aging effects of the components in the following systems:

In Catawba and McGuire —
- auxiliary feedwater
- auxiliary steam
- demineralized water or make-up demineralized water
- feedwater
- feedwater pump turbine exhaust or turbine exhaust
- liquid radwaste or liquid waste recycle
- main steam
- main steam supply to auxiliary equipment
- main steam vent to atmosphere
- nuclear sampling
- steam generator blowdown or steam generator blowdown recycle
- steam generator wet lay-up recirculation

In Catawba only —
- condensate
- condensate storage
- equipment decontamination

In McGuire only —
- liquid waste monitor and disposal
- conventional chemical addition

For the fuel oil environment, the Chemistry Control Program manages aging effects of the components in the following systems:

In Catawba and McGuire —
- diesel generator fuel oil
- standby shutdown diesel

The staff finds the program scope to be acceptable because, for each chemical environment, the applicant specified the systems containing the components whose aging effects could be managed by the application of one of the Chemistry Control Programs specified in the LRA.

[Preventive or Mitigative Actions] The applicant's program monitors and controls the relevant conditions such as halogens, dissolved oxygen, conductivity, biological activity, and corrosion inhibitor concentrations to manage loss of material and cracking. These corrosive contaminants are either removed, their concentrations minimized, or treatments are added and/or maintained to negate their corrosive tendencies. The objective of the Chemistry Control Program is to ensure that the chemistry parameters for water and diesel fuel oil remain within the values specified by the plant's TS based on the EPRI chemistry guidelines, the plant UFSARs, and vendor recommendations for water and fuel oil quality. Although this activity will not completely eliminate damaging effects of the chemical environments to which the components are exposed, the program will reduce their severity and will ensure that resultant aging effects will not invalidate the functions performed by the affected components. The staff finds that these procedures are adequate because they include all of the activities needed to mitigate age-related effects that are within the scope of license renewal.

[Parameters Inspected or Monitored] The Chemistry Control Program monitors the parameters specified in the plant's TS, based to large extent, on the EPRI guidelines. The staff finds that, by monitoring these parameters, the applicant will obtain the information needed for evaluation of the operational conditions in the system exposed to the water and fuel oil environments.

[Detection of Aging Effects] The Chemistry Control Program is a mitigative program and, as such, is not credited for detecting aging effects. The staff finds this acceptable.

[Monitoring and Trending] The Chemistry Control Program measures the relevant parameters within specified frequencies. From these measurements, performed over a time period, trends in water and fuel oil chemistry characteristics can be established. This will permit the applicant to make appropriate adjustments to the chemistry in the systems included in the scope of the program in the LRA. The staff finds that this approach will ensure effectiveness of the Chemistry Control Program.

[Acceptance Criteria] The acceptance criteria for the chemistry parameters to be monitored in the systems carrying borated water, closed cooling water, treated water and diesel fuel oil are determined by TS requirements, EPRI guidelines, the UFSAR, and vendor recommendations for water and fuel oil quality. They are specific for different chemistry environments. The staff finds these criteria acceptable because the limits imposed by them ensure that the aging effects for all the components within the scope of the program in the LRA will be properly managed.

[Operating Experience] The current operating experience for the systems covered by the Chemistry Control Program has demonstrated the effectiveness of the program. Aging effects in all the components exposed to the borated and treated water and to the fuel oil were successfully managed. The components in the component cooling systems exposed to closed cooling water exhibited instances of cracking at welds due to nitrite-induced stress corrosion of carbon steel. However, this source of corrosion was eliminated by a suitable modification of the Chemistry Control Program. The staff finds that by following the procedures specified in the current Chemistry Control Program, the applicant will ensure that the aging effects will be properly managed.

3.0.3.2.3 FSAR Supplement

The applicant provided, in Appendix A-1 (McGuire) and A-2 (Catawba), new FSAR sections describing the Chemistry Control Program. The information provided for the FSAR is consistent with the program described in Appendix B; however, the applicant did not include a discussion in the FSAR supplement regarding the specific TS and the EPRI guidelines that are mentioned in Appendix B for the Chemistry Control Program. This issue was characterized as SER open item 3.0.3.2.3-1. In its response dated October 28, 2002, the applicant added references to improved technical specifications (ITS) 5.5.10 and 5.5.13 (for McGuire and Catawba) and SLC requirements (16.5-7, 16.8-3, and 16.9-7 for McGuire, and 16.5-3, 16.7-9, and 16.8-5 for Catawba), as well as the following additional information to the original FSAR supplement:

> The Chemistry Control Program contains system-specific acceptance criteria that are based on the guidance provided in EPRI PWR Primary Water Chemistry Guidance, EPRI PWR Secondary Water Chemistry Guidelines, and EPRI Closed Cooling Water Chemistry Guidelines.

The staff reviewed the applicant's response to open item 3.0.3.2.3-1. On the basis of its review of this additional information, the staff finds that the revised FSAR supplement is consistent with the program described in Appendix B of the LRA and open item 3.0.3.2.3-1 is closed.

3.0.3.2.4 Conclusion

The staff has reviewed the Chemistry Control Program in Section 3.6 of LRA Appendix B and the applicant's responses to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Chemistry Control Program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.3 Containment Inservice Inspection Plan - IWE

The applicant described its Containment Inservice Inspection (ISI) Plan in Section B.3.7 of LRA Appendix B. This plan is credited with managing the potential aging of containment structures within the scope of license renewal. The staff reviewed Section B.3.7 of LRA Appendix B to determine whether the applicant has demonstrated that the Containment ISI Plan will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.3.1 Technical Information in the Application

Section B.3.7 of LRA Appendix B describes the ISI Plan - IWE. The purpose of this plan is to manage the aging effect of loss of material for the ASME Code Class MC pressure retaining steel components and their integral attachments for the period of extended operation. Section B.3.7 of LRA Appendix B summarizes the plan as follows:

> The "Containment Inservice Inspection Plan - IWE" was developed to implement applicable requirements of 10 CFR 50.55a. Section 50.55a(g)(4) requires that throughout the service life of nuclear power plants, components which are classified as either Class MC or Class CC pressure retaining components and their integral attachments must meet the requirements, except design and access provisions and pre-service examination requirements, set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in §50.55a(b). Furthermore, §50.55a(g)(4)(v)(A) requires that metal containment pressure retaining components and their integral attachments must meet the In service inspection, repair, and replacement requirements applicable to components which are classified as ASME Code Class MC. These requirements are subject to the limitation listed in paragraph (b)(2)(vi) and the modifications listed in paragraphs

> (b)(2)(viii) and (b)(2)(ix) of §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the components [Reference B - 20]. The "Containment Inservice Inspection Plan - IWE" is a condition monitoring program.

The components within the scope of Subsection IWE at McGuire and Catawba are metal containment pressure retaining components and their integral attachments; metal containment pressure retaining bolting; and metal containment surface areas, including welds and base metal.

The applicant concluded that the continued implementation of Containment ISI Plan - IWE provides reasonable assurance that the containment steel components will be managed such that the component intended function(s) will be maintained consistent with the current licensing basis for the period of extended operation.

3.0.3.3.2 Staff Evaluation

The staff's evaluation of the Containment ISI Plan - IWE focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the administrative controls are implemented through administrative procedures. The staff's evaluation of the administrative controls is provided in Section 3.0.4 of this SER. The remaining elements are discussed below.

[Program Scope] Section B.3.7 of LRA Appendix B provides the following information related to the scope of the inspection activities:

> The scope of the "Containment Inservice Inspection Plan - IWE" includes examination of items specified in Subsection IWE-1000, except for items that are non-mandatory as documented in 10 CFR 50.55a(b)(2)(ix)(C) and for items whose examinations have been eliminated as a result of approved alternatives submitted in accordance with 10 CFR 50.55a(a)(3). The components within the scope of Subsection IWE at McGuire and Catawba are metal containment pressure retaining components and their integral attachments; metal containment pressure retaining bolting; and metal containment surface areas, including welds and base metal. Subsection IWE exempts from examination (1) components that are outside the boundaries of the containment as defined in the plant-specific design specification; (2) embedded or inaccessible portions of containment components that met the requirements of the original construction code of record; (3) components that become embedded or inaccessible as a result of vessel repair or replacement, provided IWE-1232 and IWE-5220 are met; and (4) piping, pumps, and valves that are part of the containment system, or which penetrate or are attached to the containment vessel.
> 10 CFR 50.55a(b)(2)(ix) specifies additional requirements for inaccessible areas. It states that the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

The scope of this program is in accordance with the IS requirements of 10 CFR 50.55a, and is therefore acceptable to the staff.

[Preventive Action] There are no preventive actions taken as part of this program. Since this is a condition monitoring program, the applicant prefers not to take credit for certain preventive measures, such as coating. The staff did not identify the need for any additional preventive actions, and finds the applicant's approach acceptable.

[Parameters Monitored or Inspected] Section B.3.7 of LRA Appendix B describes the inspections. Coated surfaces are examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Uncoated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, surface discontinuities, dents, and other signs of surface irregularities. Moisture barriers are examined for wear, erosion, separation from surfaces, embrittlement/cracking, or other defects that may permit moisture intrusion to inaccessible surfaces of the containment. Bolted connections are examined for defects that could affect leak-tightness or structural integrity. Table IWE-2500-1 specifies seven categories for examination, and references the applicable section in IWE-3500 for the aging effects that are evaluated.

The LRA states that the Containment ISI Plan - IWE does not require monitoring or inspection of the following items in accordance with Table IWE-2500-1:

- Category E-B, Items E3.10, E3.20, and E3.30 (containment penetration welds, flange welds, and nozzle-to-shell welds)
- Category E-D, Items E5.10 and E5.20 (seals and gaskets)
- Category E-F, Item E7.10 (dissimilar metal welds)
- Category E-G, Item E8.20 (bolted connections - bolt torque or tension)

By letter dated January 28, 2002, the staff requested, in RAI B.3.7-1, information related to the exclusion of Categories E-B, E-D, E-F, and E-G from the program. In its response dated March 11, 2002, the applicant provided the following:

> Category E-B
> Categories E-B (Pressure Retaining Welds) and E-F (Pressure Retaining Dissimilar Metal Welds) examinations are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is 10 CFR 50.55a(b)(2)(ix)(C) and SECY-96-080, which states that "the NRC concludes that requiring these inspections is not appropriate. There is no evidence of problems associated with welds of this type in operating plants.
>
> Category E-D
> Category E-D, Item 5.10 (Seals) and Item E5.20 (Gaskets) examinations are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is documented in Duke Energy Corporation Request for Relief Serial No. 98-GO-001, approved by SER submitted by NRC letter dated September 3, 1998. Alternative examinations to be performed are as follows:
>
>> The leak-tightness of containment pressure retaining seals and gaskets will be verified by leak rate testing in accordance with 10 CFR 50, Appendix J, as required by Technical Specifications
>
> Category E-D, Item E5.30 (Moisture Barriers) are NOT excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba.
>
> Category E-G
> Category E-G, Item E8.20 (Bolt Torque or Tension Tests for Bolted Connections) are excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba. The basis for excluding these examinations is documented in Duke Energy Corporation Request for Relief Serial No. 98-GO-002, approved by SER submitted by NRC letter dated November 24, 1998. Alternative examinations to be performed are as follows:
>
> (1) Bolted connections shall receive a visual, VT-1 examination in accordance with requirements of Table IWE-2500-1, Examination Category E-G, Pressure Retaining Bolting, Item No. E8.10, and

(2) A local leak rate test shall be performed on all containment penetrations, airlocks, and other pressure retaining bolted connections in accordance with 10 CFR 50, Appendix J.

Category E-G, Item E8.10 (Bolted Connections Visual, VT-1) are NOT excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba.

With regard to Categories E-B and E-F, the staff notes that, for the reasons cited in SECY-96-080 and quoted by the applicant, 10 CFR 50.55a(b)(2)(ix)(C) makes the Category E-B (pressure retaining welds) and Category E-F (pressure retaining dissimilar metal welds) examinations optional. However, if an examination (general or VT-3) indicates loss of material or degradation of these welds, the users of 10 CFR 50.55a should perform the examinations as required by Subsection IWE. For example, the staff is aware of problems with containment bellows where the dissimilar metals (stainless steel and carbon steel) are welded. However, this issue is discussed in detail in the staff's evaluation of LRA Sections 3.5 and 4.6 and in Section 3.0.3.4 of this SER. Thus, the staff considers this response to be acceptable.

With regard to Category E-D, the staff notes that a review of the cited relief request indicates that the applicant is implementing the approved alternative of ensuring the leak-tightness of containment pressure retaining seals and gaskets by leak rate testing in accordance with 10 CFR 50, Appendix J, as required by TS. With regard to Category E-G, a review of the cited relief request indicates that the applicant is implementing the approved alternative of performing visual (VT-1) examinations and leak rate tests in accordance with the approved alternative, and that the leak rate testing is in accordance with 10 CFR Part 50, Appendix J, as required by the TS. Since the applicant received relief from this requirement, the staff finds the applicant's response and the program element acceptable.

[Detection of Aging Effects] Section B.3.7 of LRA Appendix B states that the extent and frequency of examinations are specified in IWE-2400 and IWE-2500, and that the method of examination for each item is specified in IWE-2500 and Table IWE-2500-1. Augmented inspections are performed as described below. The staff concludes that the inspections will detect loss of material before there is a loss of structure or component intended function(s). The staff finds this acceptable.

[Monitoring and Trending] Section B.3.7 of LRA Appendix B states that the frequency and scope of examinations are sufficient to ensure that aging effects would be detected before they would compromise the design basis requirements. The LRA states the following:

> The extent and frequency of examinations are specified in IWE-2400 and IWE-2500. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation. Subsection IWE examinations are performed as prescribed during each ten year interval. The method of examination for each item is specified in IWE-2500 and Table IWE-2500-1.
>
> All surface areas are monitored by virtue of examinations performed in accordance with IWE-2400 and IWE-2500. When component examination results require evaluation of flaws, evaluation of areas of degradation, or repairs, and the component is found to be acceptable for continued service, the areas containing such flaws, degradation, or repairs shall be reexamined during the next inspection period, in accordance with Examination Category E-C (containment surfaces requiring augmented examination). When these reexaminations reveal that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods, these areas no longer require augmented examination in accordance with Examination Category E-C. IWE-2430 requires that (a) examinations performed during any one inspection that reveal flaws or areas of degradation exceeding the acceptance standards shall be extended to include an

additional number of examinations within the same category approximately equal to the initial number of examinations, and (b) when additional flaws or areas of degradation that exceed the acceptance standards are revealed, all of the remaining examinations within the same category must be performed to the extent specified in Table IWE-2500-1 for the inspection interval. Alternatives to these examination requirements are provided in 10 CFR 50.55a(b)(2)(ix)(D), and as documented in approved Requests for Relief, submitted in accordance with 10 CFR 50.55a(a)(3).

The LRA describes a complete procedure for monitoring and trending; however, it does not discuss the specific areas identified for augmented inspection. By letter dated January 28, 2002, the staff requested, in RAI B.3.7-2, a summary of such areas for each of the plants. In its response dated March 11, 2002, the applicant stated that the Inservice Inspection requirements for Steel Containment Vessels at McGuire and Catawba Nuclear Stations currently comply with 10 CFR 50.55a and the ASME Boiler and Pressure Vessel Code, Section XI, 1992 Edition with the 1992 Addenda, as modified by approved Requests for Relief granted in accordance with 10 CFR 50.55a(a)(3)(i) and (a)(3)(ii). The applicant also described, in detail, the following areas that are designated for augmented inspection for each unit of McGuire and Catawba:

<u>McGuire 1:</u>
1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Moisture barriers at the embedment zone around the periphery of the exterior side of the steel containment vessel
    - Moisture barrier at the interface between the steel containment vessel and the Fuel Transfer Tube Radiation shielding concrete on the exterior side of the steel containment vessel

The above items were selected for augmented examination due to conditions observed on these moisture barriers when examined in accordance with Table IWE-2500-1, Examination Category E-D, Item E5.30.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
    - Surface areas directly behind the insulation panel attached to the interior surface of the containment vessel approximately 36" above the embedment zone. These locations were selected for examination because the top of the insulation panel had not been sealed to prevent moisture intrusion, and because evidence of moisture intrusion had been noted during past inspections. Examination area is approximately 12" wide and extends nearly all of the way around the periphery of the containment vessel.
    - Surface areas directly behind cork expansion joint material between the interior concrete structure and steel containment vessel at Elevation 752' + 1 3/8" between azimuths 104° and 122° (approx.). This location was selected for examination because the cork expansion joint material has not been removed at this location, and it is still possible for moisture to accumulate behind the expansion joint material. During past inspections, some staining had been observed beneath this area, indicating that moisture intrusion had occurred.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

<u>McGuire 2:</u>
1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
    - Moisture barriers at the embedment zone around the periphery of the exterior side of the steel containment vessel, between azimuths 0° and 180° (approx.) and between azimuths 270° and 360° (approx.)
    - Moisture barrier at the interface between the steel containment vessel and the Fuel Transfer Tube Radiation shielding concrete on the exterior side of the steel containment vessel

The above items were selected for augmented examination due to conditions observed on these moisture barriers when examined in accordance with Table IWE-2500-1, Examination Category E-D, Item E5.30.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
• Examination areas are identical to those on Unit 1, except that the following additional area is also examined:
• Surfaces between the steel containment vessel and the Fuel Transfer Tube Radiation Shielding concrete on the interior of the vessel, between elevations 728'+4" and 729'+4". Examination area extends approximately 3 feet on each side of the Fuel Transfer Tube and is examined from the exterior of the containment vessel. This location was selected for examination because general visual examinations conducted in accordance with Table IWE-2500-1, Examination Category E-A, Item E1.11 detected evidence of borated water at this location on the interior surface of the containment vessel.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

Catawba 1:

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
• Surface areas on the interior of the containment vessel, located between azimuths 247° and 303° (approx.), below Elevation 593'+10 ½", along the top of the cork expansion joint material installed between the interior concrete structure and the containment vessel at the VX Fan Pit floor. This location was selected for examination because most of the cork expansion joint material has not been removed at this location, moisture intrusion has occurred, and some rusting and minor pitting has been observed on containment shell surfaces along the top of the cork material.

2. The following items/areas are examined in accordance with Category E-C, Item E4.12:
• Surface areas directly behind the cork expansion joint material installed between the containment vessel and interior concrete structure at the VX Fan Pit floor between azimuths 247° and 303° (approx.), between Elevations 593'+9 3/8" and 596'+9 3/8" (approx.). This location was selected for examination because conditions noted at the VX Fan Pit floor on the interior of the containment vessel were considered to be an indicator of possible degradation of the containment vessel shell plate behind the expansion joint material.
• Surface areas directly behind cork expansion joint material along the top of floor joints between the interior concrete structure and steel containment vessel at the following locations. These locations were selected for examination because most of the cork insulation panel has not been removed, and evidence of moisture and staining has been observed beneath these areas on the interior side of the vessel:
  - between Elevations 565'+5 5/8" and 564'+5 5/8" (approx.), between azimuths 0° to 250°, and 270° to 360° (approx.)
  - between Elevations 579'+1 3/8" and 578'+1 3/8" (approx.), between azimuths 104° to 122° (approx.)
  - between Elevations 594'+8 3/8" and 593'+8 3/8" (approx.), between azimuths 0° to 247°, and 303° to 360° (approx.). This area is located at the ice condenser floor where it may be possible for moisture to accumulate against the containment vessel. The risk of potential degradation is considered higher here than for other areas of the containment vessel covered by insulation behind the ice condensers.

Ultrasonic thickness measurements on the above surfaces are performed from the exterior of the containment vessel.

Catawba 2:

1. The following items/areas are examined in accordance with Category E-C, Item E4.11:
• Examination areas are identical to those on Unit 1, except that the following additional items are also examined:
• Equipment Hatch latch bolts. These were selected for examination due to conditions found during the performance of Table IWE-2500-1, Category E-G, Item E8.30 examinations.

2. Items/areas that are examined in accordance with Category E-C, Item E4.12 are identical to those on Unit 1.

The applicant further indicated that these areas shall be examined in accordance with IWE-2420(c) until such time that the flaws, areas of degradation, or repairs remain essentially unchanged for three consecutive inspection periods. If other areas containing flaws or degradation are discovered during the performance of IWE examinations, and these areas warrant examination in accordance with Table IWE-2500-1, Category E-C, these other areas shall also be examined in accordance with IWE-2420. The staff finds that this detailed response to RAI B.3.7-2 indicates that the applicant was thorough in identifying the parameters to be monitored. The staff finds the applicant's approach acceptable.

[Acceptance Criteria] Section B.3.7 of LRA Appendix B states that this program implements the acceptance criteria specified in Table IWE-3410-1 for each examination category (E-A, E-C, etc.). Areas that do not meet the acceptance standards of Table IWE-3410-1 are be accepted by engineering evaluation, repair, or replacement, as required by IWE-3122. The staff finds the acceptance criteria are consistent with requirements of 10 CFR 50.55a and, therefore, acceptable.

[Corrective Action and Confirmation Process] Section B.3.7 of LRA Appendix B provides information on the corrective actions and confirmation process required by the Code. Subsection IWE states that components whose examination results indicate flaws or areas of degradation that do not meet the acceptance standards listed in Table IWE-3410-1 can be considered acceptable if an engineering evaluation indicates that the flaw or area of degradation is nonstructural in nature or has no effect on the structural integrity of the containment, or if such areas are repaired in accordance with IWE-3122.2 and IWE-4000 or replaced in accordance with IWE-3122.3 and IWE-7000. Such areas are subject to the requirements of IWE-2420(b) and (c), and additional examination requirements of IWE-2430, as modified by 10 CFR 50.55a(b)(2)(ix)(D).

When repairs are performed, the requirements of IWE-3124 apply, and the recorded results of reexaminations must demonstrate that the repair meets the acceptance standards set forth in Table IWE-3410-1. For repairs and replacements, the pre-service examination requirements of IWE-2200(d) and the system pressure test requirements of IWE-5000 shall be satisfied, providing additional assurance that the repairs or replacements are acceptable. Since the corrective action and confirmation process is in accordance with the IWE requirements as incorporated by reference in 10 CFR 50.55a, the staff finds them acceptable.

[Operating Experience] Section B.3.7 of LRA Appendix B describes the operating experience for McGuire and Catawba containment ISI activities as follows:

> McGuire Operating Experience
> Containment Inservice Inspection Plan - IWE inspections have been performed at McGuire during 1EOC-13, 1EOC-14, 2EOC-12, and 2EOC-13. Inspection results have included the following:
>
> - coatings degradation
> - loss of material due to corrosion of Steel Containment Vessel (SCV) shell, stiffener rings, penetration sleeves, process piping, and bolted connections
> - missing and cracked/separated moisture barriers
>
> Conditions which required reportability in accordance with 10 CFR 50.55a(b)(2)(ix) are documented in letters to the NRC. For example, the most recent McGuire Containment Inservice Inspection that detected conditions requiring reporting is documented in a letter to the NRC dated January 11, 2001.

Prior to implementation of the Containment Inservice Inspection Plan- IWE, inspections were performed in accordance with Appendix J to 10 CFR Part 50. Degradation due to corrosion of the steel containment vessel was identified during these inspections and was documented in LERs 89-20 and 90-06. The corrosion was evaluated and it was determined that the corrosion did not inhibit the ability of the SCV to perform its intended functions. The steel containment vessel was recoated and modifications were made to minimize the potential for reoccurrence.

Catawba Operating Experience
Containment Inservice Inspection Plan - IWE inspections have been performed at Catawba during 1EOC-11, 1EOC-12, 2EOC-9, and 2EOC-10. Inspection results have included the following:

- coatings degradation
- loss of material due to corrosion of Steel Containment Vessel (SCV) shell, stiffener rings, penetration sleeves, process piping, and bolted connections
- missing/damaged parts on equipment hatch latch bolting
- missing and cracked/separated moisture barriers

Conditions which required reportability in accordance with 10 CFR 50.55a(b)(2)(ix) are documented in letters to the NRC. For example, the most recent Catawba Containment Inservice Inspection that detected conditions requiring reporting is documented in a letter to the NRC dated May 1, 2000.

The inspection activities have identified a number of degradations at both stations, all of which have been corrected or determined not to impact the intended function of the component. The variety of items identified by past inspections indicates that this program will be effective in managing aging of the containment.

3.0.3.3.3 FSAR Supplement

A review of the FSAR supplements in Section 18.2.5 of Appendices A1 and A2 of the LRA for McGuire and Catawba, respectively, indicates that the applicant has described the basic features of Containment ISI Plan - IWE. The staff considers the summary description in UFSAR acceptable.

3.0.3.3.4 Conclusion

The staff has reviewed the information provided in Section B.3.7 of LRA Appendix B and the summary description of the inspection activities in Appendix A of the LRA. In addition, the staff considered the applicant's response to the staff's RAIs provided in a letter to the NRC dated March 11, 2002. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the Containment ISI Plan - IWE will adequately manage the aging effects such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.4 Containment Leak Rate Testing Program

Section B.3.8 of LRA Appendix B describes the applicant's Containment Leak Rate Testing Program activities as they are credited for license renewal. The applicant considers these activities to be supplemental to the Containment ISI Plan - IWE program described in Section B.3.7 of LRA Appendix B. The Containment Leak Rate Testing Program would detect degradation that had advanced to the point of allowing leakage at the test's required pressure condition. The staff reviewed Section B.3.8 of LRA Appendix B to determine whether the applicant has demonstrated that Containment Leak Rate Testing Program activities will supplement the Section IWE inspections to adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.4.1 Technical Information in the Application

Section B.3.8 of LRA Appendix B identifies the loss of material of pressure boundary components and cracking of bellows as aging effects requiring management for the period of extended operation. The purpose of the Containment Leak Rate Testing Program is to supplement the Containment Inservice Inspection Plan- IWE, which implements the provisions of the ASME Code Section XI, Subsection IWE, and is the primary method for detection of aging effects for the steel components of containment. The Containment Leak Rate Testing Program is a performance monitoring program which credits Type A and Type B tests to detect containment pressure boundary components that had degraded to the point of allowing leakage at the test's required pressure condition. The LRA states the following:

> One of the conditions of all operating licenses for water-cooled power reactors is that containment shall meet the leakage test requirements set forth in 10 CFR Part 50, Appendix J. The purposes of these tests are to ensure that:
>
> (a) leakage through the (1) containment and (2) systems and components penetrating containment shall not exceed allowable leakage rate values specified in the Technical Specifications or associated bases, and
> (b) periodic surveillances of containment penetrations and isolation valves are performed.
>
> The Containment Leak Rate Testing Program contains three types of tests: Type A, which are integrated leak rate tests intended to measure the overall leakage rate of the containment; Type B, which are tests intended to measure leakage of containment penetrations whose design incorporates resilient seals and gaskets including airlock door seals and equipment hatch gaskets; and Type C, which are tests to measure containment isolation valve leakage.
>
> Of these three tests, only Type A and Type B are credited for license renewal. The Type A tests would detect severe corrosion of containment pressure boundary steel components that had degraded to the point of allowing leakage at the test's required pressure condition. The Containment Leak Rate Testing Program is implemented per Technical Specifications 3.6.1, Containment, and 5.5.2, Containment Leakage Rate Testing Program.

Based on the information provided in the LRA, the applicant concluded that it is reasonable to expect the continued implementation of the Containment Leak Rate Testing Program to detect loss of material and cracking such that the intended functions of the steel containment vessel, penetrations, bellows, and hatches will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.4.2 Staff Evaluation

Although the applicant describes this program as a supplementary program for aging management of the containment pressure boundary components, the staff considers the successful completion of this program to be a demonstration that the containment and containment components are able to perform their intended function.

The program credits Type A and Type B tests to detect containment pressure boundary components that had degraded to the point of allowing leakage at the test's required pressure condition. In describing the purpose and content of the program, the applicant explicitly excludes the Type C testing from the program as not being credited for license renewal. Type C testing is performed to ensure the integrity of the containment isolation valves. In response to a staff's question related to the exclusion of Type C testing, the applicant argued that the containment isolation valves were active components, and Type C tests, which ensure their leakage characteristics, were not credited for the aging management of these valves. However, the applicant will be performing the tests in accordance with the TS requirements. Based on the understanding that the isolation valves are considered as active components of the containments, the staff finds the exclusion of Type C testing from the program acceptable.

The staff's evaluation of the Containment Leak Rate Testing Program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site work management system. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The scope of the program includes all pressure boundary components including the steel containment vessel, mechanical penetrations, bellows, electrical penetrations, airlocks, hatches, and flanges. The staff considers the applicant's inclusion of these components acceptable.

[Preventive Actions] There are no preventive actions taken as part of this program, and the staff did not identify the need for any preventive actions. This is a performance monitoring test, and the containment ISI program described in Section B.3.7 of LRA Appendix B can be considered as pertinent to the intended function of containment. However, the applicant prefers not to take credit for that program. The staff finds the applicant's position acceptable.

[Parameters Monitored or Inspected] The parameter monitored is the containment leakage rate. The testing is performed to identify leakage that could indicate loss of material and cracking.

The staff agrees that the basic parameters being monitored (i.e., the leakage through the containment pressure boundary components) may indicate loss of materials and cracking when such degradation results in unacceptable leakage through the components. The staff finds the parameters monitored acceptable.

[Detection of Aging Effects] Aging effects are detected through overall leakage during the Type A tests, combined with local leakage testing of the penetrations, bellows, and hatches during the Type B tests. Since the Containment Leak Rate Testing Program is used as a supplement to the Containment ISI Plan - IWE, and is only credited with identifying components that have degraded to the point where leakage occurs, the staff finds this acceptable.

[Monitoring and Trending] As described in Section B.3.8 of LRA Appendix B, aging effects are detected through overall leakage during the Type A tests, combined with local leakage testing of the penetrations, bellows, and hatches during the Type B tests. The Type A tests are performed once every 10 years in accordance with Option B, as described in NRC Regulatory Guide 1.163. For McGuire, the Type B tests are performed in accordance with 10 CFR Part 50, Appendix J, Option A requirements. For Catawba, the Type B tests are performed in accordance with 10 CFR Part 50, Appendix J, Option B requirements. All bellows are leak tested in accordance with Technical Specification surveillance requirements. The parameters to be monitored are leakage rates through the primary containment and the systems and components penetrating primary containment. Unacceptable conditions are identified for corrective action and/or further evaluation. The applicant maintains data on the components such as leakage rates, total overall leakage, and containment bypass leakage to ensure that the leakage remains below the allowable limits. Since monitoring and trending will be used to ensure that leakage limits will not be exceeded, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.8 of LRA Appendix B states the following:

> The acceptance criteria are defined in Technical Specifications. The containment leakage rate acceptance criterion is less than or equal to 1.0 L_a. L_a is the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design basis LOCA. During the first plant startup following testing in accordance with this program, the leakage rate acceptance criterion is less than 0.75 L_a for Type A tests.
>
> As left leakage prior to the first startup after performing a required 10 CFR 50, Appendix J, Option A, leakage test is required to be less than 0.6 L_a for combined Type B and C leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit less than or equal to 1.0 L_a.
>
> The space between dual-ply bellows shall be subjected to a low pressure leak test with no detectable leakage. Otherwise, the assembly must be tested with the containment side of the bellows assembly pressurized to P_a and the acceptance criteria is based on the combined leakage rate for all reactor building bypass leakage paths less than or equal to 0.07 L_a.

A review of the Catawba TS indicates that the low pressure associated with the testing of dual-ply bellows varies between 3 and 5 psig. By letter dated January 28, 2002, the staff requested, in RAI B.3.8-1, additional information related to how the combined leakage rate for all reactor building bypass (i.e., 0.07L_a) is related to the leakage through the individual bellows, as the bellows will leak into the annulus between the primary containment and the reactor building. In its response dated March 11, 2002, the applicant provided the following:

> The acceptance criterion of 0.07L_a is specified in Technical Specification Surveillance Requirement 3.6.3.8 as the maximum combined leakage rate. This criterion includes the leakage from all penetration bellows. The leakage from the bellows would be added to all other bypass leakage. The total combined leakage is required to be less than 0.07L_a. As such, the test leakage of any individual bellows assembly will be less than 0.07L_a over the extended life of the plant during normal operations as well as during design basis events.

The applicant's allowable combined leakage from all bypass leakage (including those from all penetrations with bellows) will be less than 0.07L_a. The staff believes that any significant bellow degradation will be detected by this procedure. Hence, the staff finds the applicant's acceptance criterion for detecting bellow degradation reasonable and acceptable.

[Operating Experience] Section B.3.8 of LRA Appendix B states the following:

> Numerous Type A and Type B tests have been performed at McGuire and Catawba over the course of operation. Results have shown that all containment steel components such as the steel

containment vessel and flued head penetrations have successfully passed the Type A tests. Results of previous Type B tests have identified leakage of the mechanical bellows as described below.

McGuire Operating Experience
McGuire has identified several leaking penetration bellows after twenty years of operation, about half of which are attributable to damage incurred during construction. Some of the original McGuire bellows were repaired/replaced prior to initial plant startup. Main Steam penetration 1M-441 bellows was replaced during refueling outage 1EOC-14 (Spring 2001). The remaining bellows with leakage are within Technical Specification limits. The leakage test results are conservatively added to the overall containment leakage and are included in bypass or non-bypass leakage calculations, as appropriate, with each remaining below allowable Technical Specification limits.

Catawba Operating Experience
Catawba has identified a few penetration bellows that failed the low-pressure bellows test. The bellows leakage from these tests was added to the overall leakage and included in the containment bypass leakage calculations. The total overall leakage and containment bypass leakage remains below the allowable Technical Specification limits.

The staff sought to better understand the extent of degradation of containment bellows at McGuire and Catawba containments. By letter dated January 28, 2002, the staff requested, in RAI B.3.8-2, the following information:

1. For the McGuire and the Catawba plants, provide the number of bellows where leakages have been found, and the number of bellows that have been replaced, since the beginning of operation of these plants.

2. For the McGuire and the Catawba plants, provide the number of Duke Class A and Class B bellows that are currently leaking (cracked).

3. Table 3.5-1 "Aging Management Review Results," indicates that the function of the bellows and mechanical penetrations is to provide a pressure boundary and/or fission product barrier. Provide justification for operating with leaking (cracked) bellows during the period of current operation and the period of extended operation.

In its response dated March 11, 2002, the applicant provided the following response:

1. For McGuire, twenty (20) bellows are designated as leaking. One bellows has been replaced at McGuire. For Catawba, three (3) bellows are designated as leaking No bellows have been replaced at Catawba. For additional information concerning the replaced bellows, reference Appendix B.3.8 of the Application and Response to RAI 3.5-5.

2. No Class A bellows exist at Catawba or McGuire because there are no Class 1 pipe penetrations through the containment. The answer for question 1 applies to Class B penetrations.

3. Technical Specification 3.6.1 contains the leakage limits for continued operation. These leakage limits were used in the analysis of off-site doses resulting from accidents. The leakage rate is defined in 10 CFR 50, Appendix J. The leakage of the bellows remains below the limits specified in Technical Specification 3.6.1.

The above information, and the applicant's response to RAI 3.5-5 (documented in Section 3.5 of this SER), indicate that the applicant is aware of the conditions of containment bellows at McGuire and Catawba plants, and is taking actions to ensure that the existing individual and cumulative leakages from the bellows are within the requirements of the plants' TS.

3.0.3.4.3 FSAR Supplement

The program is described in the Technical Specifications, not in the UFSARs. The description in the Technical Specifications is sufficient, and the staff finds this acceptable.

3.0.3.4.4 Conclusion

The staff has reviewed the information provided in Section B.3.8 of LRA Appendix B and the applicant's response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the Containment Leakage Rate Testing Program can effectively supplement the Containment ISI Plan - IWE in managing the effects of aging associated containment components such that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.5 Fire Barrier Inspections

The applicant described its Fire Barrier Inspections program in Section B.3.12.1 of LRA Appendix B. The applicant credits this inspection activity with managing the potential aging effects of fire barriers under the scope of license renewal. These inspections are required by SLC 16.9.5. The staff reviewed Section B.3.12.1 of LRA Appendix B to determine whether the applicant has demonstrated that fire barrier inspection activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.5.1 Technical Information in the Application

Section B.3.12.1 of LRA Appendix B describes the Fire Barrier Inspections program. The purpose of these inspections is to manage the aging effects of the fire barriers, such as walls, floors, ceilings, and doors, for the period of extended operation. The Fire Barrier Inspections are credited with monitoring the aging effects of loss of material due to corrosion of fire doors, cracking of fire walls, and cracking, delamination, and separation of fire barrier seals. The inspections cover all fire barriers and all sealing devices in fire barrier penetrations.

3.0.3.5.2 Staff Evaluation

The staff's evaluation of the Fire Barrier Inspection activity of the Fire Protection Program focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action program, while the administrative controls are governed by SLCs and implemented through plant procedures and the site work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.12.1 of LRA Appendix B identifies the scope of the Fire Barrier Inspections activities as including all fire barriers, such as walls, floors, ceilings, doors, and all sealing devices in fire barrier penetrations, such as fire doors and penetration seals. All fire barriers and all sealing devices are identified in the implementing procedures and associated drawings. The staff concludes that the applicant included the in-scope fire barriers in the inspections, and finds this acceptable.

[Preventive Actions] There are no preventive or mitigative actions as part of this program, and the staff has not identified the need for any.

[Parameters Monitored or Inspected] The Fire Barrier Inspections require visual examination for loss of material due to corrosion of fire doors, cracking of fire walls, and cracking, delamination, and separation of fire barrier penetration seals. The staff finds that the parameters monitored will permit timely detection of the aging effects and are, therefore, acceptable.

[Detection of Aging Effects] The applicant performs visual inspections and functional testing to detect the aging effects described above. Visual inspection and functional tests are capable of detecting the effects of aging because defects would be identified and evaluated using the corrective action before failure would occur. Accordingly, the staff finds visual inspections and functional tests appropriate and acceptable for these inspections.

[Monitoring and Trending] The aging effects are monitored, but not trended. Aging effects are detected through visual examination of the fire barrier, fire doors, and fire barrier penetration seals. All exposed surfaces of each fire barrier is inspected at least once every 18 months in accordance with SLC 16.9.5. Fire doors are visually inspected and functionally tested at least every 6 months per SLC 16.9.5; 10 percent of each type of fire barrier penetration seal is inspected at least once every 18 months per SLC 16.9.5. The staff finds the methods and frequency of inspections consistent with industry practice and operating experience. The monitoring frequency is adequate to detect defects, since degradation to failure will not occur within the monitoring interval. Accordingly, the staff finds the monitoring acceptable, and did not identify a need for trending.

[Acceptance Criteria] The acceptance criteria for doors and fire barriers are based on the absence of holes, cracks, or gaps through visual examination. The acceptance criteria for fire barrier penetration seals are no visual indications of cracking, shrinkage, or separation of layers of material. In addition, separation from wall and through-holes shall not exceed limits as specified in the procedure.

The LRA stated that "separation from wall and through-holes shall not exceed limits as specified in the procedure." In RAI B 3.12.1-1, the staff requested a description of the inspection procedures that permit the timely detection of cracking/delamination and separation of the fire barrier penetration seals. The staff also requested the specific limits and the basis for their selection. By letter dated March 11, 2002, the applicant provided the following response:

> Fire penetration seals are inspected on a frequency as directed by Selected Licensee Commitment (SLC) 16.9.5. The limits for the acceptance criteria are specified in the station procedures. The limits are discussed in more detail below.
>
> Crumbling, gouges or voids on fiberboard damming surface shall not exceed one-half (½) inch deep by one (1) inch length and width.

> Fiberboard dams should be as flush with the fire barrier and with other pieces of damming board as possible. A maximum one-quarter (1/4) inch gap is acceptable.
>
> For fire barrier penetration seals without permanent damming, the limit of separation of foam from the barrier perimeter or components passing through the seal shall not exceed one-quarter (1/4) inch wide by three (3) inches deep and unlimited length.
>
> For fire barrier penetration seals without permanent damming, gouges or voids on the front side or backside surface of the foam shall not exceed one-half (½) inch deep by one (1) inch length and width.
>
> For fire barrier penetration seals with permanent damming, the limit of separation of foam from the barrier perimeter or components passing through the seal shall not exceed three-quarter (3/4) inch wide by four (4) inches deep and unlimited length.
>
> For fire barrier penetration seals with permanent damming, gouges or voids on the front side or backside surface of the foam shall not exceed three-quarter (3/4) inch wide by four (4) inches deep and unlimited length.
>
> The acceptance criteria are based on experimental tests and engineering analysis as documented in station specifications.

The staff finds the applicant's acceptance criteria and the basis thereof reasonable and acceptable because effects of aging will be detected and will be evaluated using the corrective action program before failure would occur.

[Operating Experience] The operating experience related to the Fire Barrier Inspections at McGuire and Catawba indicates that degradation of fire barrier was detected prior to loss of function. Identified degradation has been associated with installation problems and generally not due to aging. The applicant has documented correspondence with the NRC discussing installation deficiencies with fire barrier penetration seals. When a deficiency was noted by the applicant during an audit, additional barrier penetrations were inspected. Generally, these deficiencies were attributed to installation problems. Corrective actions included additional inspections, repair, and/or replacement activities. The staff finds that, based on the operating experience, the applicant will effectively maintain the fire barriers during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.5.3 FSAR Supplement

Appendix A of the LRA does not contain an FSAR supplement for this program; however, the staff finds that the description in SLC 16.9.5 is sufficient and acceptable.

3.0.3.5.4 Conclusion

The staff has reviewed the information provided in Section B.3.12.1 of LRA Appendix B and additional information provided by the applicant by letter dated March 11, 2002. On the basis of its review as discussed above, the staff concludes that the continued implementation of the Fire Barrier Inspections provides reasonable assurance that the aging effects will be managed such that the intended functions of the fire barriers will continue to be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.6 Flow-Accelerated Corrosion Program

The applicant described its Flow-Accelerated Corrosion Program in Section B.3.14 of LRA Appendix B. The staff reviewed the application to determine whether the applicant has demonstrated that the Flow-Accelerated Corrosion Program will adequately manage the applicable effects of aging in the plant during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.6.1 Technical Information in the Application

The applicant described its Flow-Accelerated Corrosion Program as a condition monitoring program that monitors specific component or material parameters to detect the presence, and assess the extent, of flow-accelerated corrosion (FAC). For license renewal, the Flow-Accelerated Corrosion Program will focus inspections on piping, and is credited for managing loss of material due to FAC of carbon steel piping, valves, and cavitating venturies within the susceptible regions of the following systems:

- auxiliary feedwater (Catawba)
- auxiliary steam
- boron recycle
- feedwater
- liquid radwaste (Catawba)
- liquid waste recycle (McGuire)
- liquid waste monitor and disposal (McGuire)
- steam generator blowdown recycle (Catawba)
- turbine exhaust (McGuire)

The applicant stated that the only portions of boron recycle, liquid radwaste (Catawba), liquid waste recycle (McGuire), and liquid waste monitor and disposal (McGuire) within the scope of license renewal that are susceptible to FAC are the supply lines from the auxiliary steam.

The applicant stated that component replacement with a non-susceptible material is initiated as part of the Flow-Accelerated Corrosion Program. Opportunities to replace components are evaluated by the applicant when related modifications are being performed on a susceptible location or when economic benefit is realized.

Loss of material due to FAC of carbon steel components is detected by inspection of susceptible component locations. The Flow-Accelerated Corrosion Program inspections focus on piping. These inspections provide symptomatic evidence of loss of material due to FAC of other components within the susceptible piping runs. Inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness. Visual examinations are also employed when access to interior surfaces is allowed by component design.

The applicant stated that if the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis. Specific corrective actions are implemented in accordance with the Flow-Accelerated Corrosion Program or the applicant's corrective action program. The applicant noted that these programs apply to all components within the scope of the Flow-Accelerated Corrosion Program.

The Flow-Accelerated Corrosion Program is not a new program for license renewal. The applicant stated that the program is consistent with the basic guidelines or recommendations provided by EPRI document NSAC-202L and experience has been gained during the operation of McGuire and Catawba.

3.0.3.6.2 Staff Evaluation

The staff's evaluation of the Flow-Accelerated Corrosion Program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant described the program scope associated with this aging management program as including carbon steel piping, valves, and cavitating venturies within the susceptible regions of the systems listed in Section B.3.14.3 of LRA Appendix B. The staff finds the scope to be acceptable because the information in the application is comprehensive and includes systems that may be vulnerable to FAC.

[Preventive or Mitigative Actions] The applicant described the Flow-Accelerated Corrosion Program as a condition monitoring program. Therefore, the Flow-Accelerated Corrosion Program does not prevent corrosion from occurring or mitigate its effect, but will identify material loss if it is occurring and allow the applicant to take action, including replacement of the component if required. The staff agrees that because the program is designed to identify FAC, it is not required to take preventive or mitigative actions. The staff finds that based on the information gained from the program, the applicant will be able to take action to repair or replace components if needed.

[Parameters Inspected or Monitored] Loss of material due to FAC of carbon steel components is detected by inspection of susceptible component locations. The Flow-Accelerated Corrosion Program inspections focus on piping. These inspections provide symptomatic evidence of loss of material due to FAC of other components within the susceptible piping runs. Inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness. Visual examinations are also employed when access to interior surfaces is allowed by component design. Because visual inspection and the NDE methods to be employed can detect wall thinning due to corrosion, and the methods are consistent with industry practice, the use of these inspection and examination techniques on the components is acceptable.

[Detection of Aging Effects] The applicant stated that, based on the information provided in the Monitoring and Trending section of the LRA, the Flow-Accelerated Corrosion Program will detect loss of material due to FAC prior to loss of component intended function. The staff finds that the methods to be employed by the applicant are consistent with current industry practice. In addition, the staff finds that the Flow-Accelerated Corrosion Program will detect loss of material due to FAC prior to loss of component intended function. Therefore, the staff finds the applicant's approach for detection of aging effects to be acceptable.

[Monitoring and Trending] The applicant stated that the program is consistent with the basic guidelines or recommendations provided by EPRI document NSAC-202L. Component wall thickness is measured using volumetric examinations, such as ultrasonic testing and radiography. Visual examinations are also employed when access to interior surfaces is allowed by component design. Component wall thickness acceptability is judged in accordance with the McGuire and Catawba component design code of record. Defined inspection locations exist in the auxiliary feedwater system (Catawba) and feedwater and steam generator blowdown recycle system (Catawba). For each system, multiple inspection locations in susceptible regions will be performed.

Other defined inspection locations cover several systems that are exposed to the same steam supply environment. Auxiliary steam, boron recycle, liquid radwaste (Catawba), liquid waste recycle (McGuire), and liquid waste monitor and disposal (McGuire) systems are all part of the same steam supply that spans these several systems. The steam is supplied from the auxiliary steam and several inspection locations exist in this run of piping.

The final system within the scope of license renewal falling within the scope of the Flow-Accelerated Corrosion Program is the turbine exhaust (McGuire). The only in scope portion of turbine exhaust (McGuire) susceptible to FAC is a few feet of ½-inch diameter piping. Because of the pipe size, ultrasonic scanning versus ultrasonic testing can be performed on this section of piping in lieu of establishing defined inspection locations. Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experience. Inspection results are monitored and trended to determine the calculated rate of material loss, to detect changes in operating or chemistry conditions, and schedule for the next inspection. The examination and inspection techniques are consistent with current industry practice and are capable of detecting FAC prior to loss of component function, therefore the staff finds the monitoring and trending to be acceptable.

[Acceptance Criteria] The applicant stated that by using the inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record. Because the applicant will be capable of detecting, trending, and correcting (if necessary) the effects of FAC before the components lose the ability to perform their intended function, the staff finds this to be acceptable.

[Operating Experience] The applicant performed a review of inspection data for the steam generator blowdown and recycle (Catawba) and auxiliary steam supplies, which revealed minimal loss of material at the inspection locations. The applicant reported that the auxiliary feedwater (particularly Catawba 2) has revealed loss of material in several locations that has resulted in material replacement in significant lengths of piping, illustrating that the program is effective in managing these components. The carbon steel that remains in the system is monitored and evaluated by the applicant as described above. The applicant reported that degradation in the feedwater system has been limited to areas associated with localized velocity. The applicant has replaced these sections of piping with wear-resistant material. The applicant has performed ultrasonic scanning on the turbine exhaust (McGuire) section of piping and minimal loss of material was detected. The applicant reports that no component failures due to FAC attributed to an inadequate Flow-Accelerated Corrosion Program have occurred in these systems.

The applicant maintains that this operating experience demonstrates that the Flow-Accelerated Corrosion Program, when continued into the period of extended operation, will be effective in managing FAC to ensure the component intended pressure boundary function under all current licensing basis design conditions. The staff finds the applicant's aging management activities described above have been effective at maintaining the intended function of the components subject to the Flow-Accelerated Corrosion Program and can reasonably be expected to do so for the period of extended operation.

3.0.3.6.3 FSAR Supplement

The applicant provided in Appendix A-1 (McGuire) and A-2 (Catawba) new FSAR sections describing the Flow-Accelerated Corrosion Program. The information provided for the FSAR is consistent with the program described in Appendix B and no changes are required.

3.0.3.6.4 Conclusion

The staff has reviewed the information in Section B.3.14 of LRA Appendix B. On the basis of its review, the staff concludes that the applicant has demonstrated that the Flow-Accelerated Corrosion Program will adequately manage aging effects associated with components subjected to FAC so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.7 Fluid Leak Management Program

The applicant described its Fluid Leak Management Program in Section B.3.15 of LRA Appendix B. The Fluid Leak Management Program is described as a comprehensive program containing many activities to manage leakage for the entire plant. The program is accomplished by visual surveillance and trending of findings. Systematic walkdowns of the auxiliary and reactor buildings are conducted to identify leakage or evidence of leakage from borated water systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Fluid Leak Management Program will adequately manage the applicable effects of aging in the plant during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.7.1 Technical Information in the Application

The applicant indicated that the purpose of the Fluid Leak Management Program is to manage loss of material due to boric acid wastage of mechanical and structural components within the scope of license renewal that are constructed of carbon steel, low-alloy steel, and other susceptible materials that are located in the auxiliary and reactor buildings. The program also manages boric acid intrusion of electrical equipment that is located in proximity to borated water systems.

The Fluid Leak Management Program is defined by the applicant as a mitigation program that contains activities developed as part of the applicant's response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." The program identifies leaks from borated water systems and initiates investigation and repair. In a letter dated January 28, 2002, the staff requested additional information from the applicant related to provisions for inspecting potentially vulnerable, inaccessible locations for boric acid corrosion. The applicant responded in a letter dated March 15, 2002.

3.0.3.7.2 Staff Evaluation

The staff's evaluation of the Fluid Leak Management Program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The Fluid Leak Management Program includes electrical, mechanical, and structural components within the scope of license renewal that are located in the auxiliary and reactor buildings where exposure to leaks from borated water systems is possible. Mechanical and structural components constructed of carbon steel, low-alloy steel, and other susceptible materials are included within the scope of the program.

Mechanical components in the following systems are within the scope of the Fluid Leak Management Program:

- annulus ventilation
- auxiliary building ventilation
- auxiliary feedwater
- auxiliary steam
- boron recycle
- (building) heating water
- chemical and volume control
- component cooling
- condensate (Catawba)
- condensate storage (Catawba)
- containment air release and addition (Catawba)
- containment air return exchange and hydrogen skimmer
- containment hydrogen sample and purge (Catawba)
- containment purge (ventilation)
- containment spray
- containment ventilation cooling water (McGuire)
- control area chilled water
- control (room) area ventilation
- feedwater
- (feedwater pump) turbine exhaust

- fire protection (interior and exterior)
- fuel handling area (or building) ventilation
- groundwater drainage
- hydrogen bulk storage
- ice condenser refrigeration
- instrument air (McGuire)
- liquid radwaste (Catawba)
- liquid waste monitor and disposal (McGuire)
- liquid waste recycle (McGuire)
- main steam
- main steam (supply) to auxiliary equipment
- main steam vent to atmosphere
- nuclear service water
- reactor coolant
- recirculated cooling water (Catawba)
- residual heat removal
- safety injection
- spent fuel cooling
- steam generator blowdown (recycle)
- steam generator wet lay-up recirculation
- turbine building sump pump system (Catawba)
- waste gas

The staff found that the scope of the Fluid Leak Management Program is acceptable because the scope is comprehensive in that it includes the systems, structures, and major components that may be affected by fluid leakage.

[Preventive or Mitigative Actions] The applicant stated that the programmatic implementation of the Fluid Leak Management Program is accomplished through visual surveillance and systematic trending of findings. All active leaks are monitored on an appropriate frequency depending on accessibility and rate of leakage. Timely action serves to mitigate loss of material due to boric acid wastage. The staff found that these procedures are adequate because they include all of the activities needed to mitigate the age-related effects that are within scope of this program.

[Parameters Inspected or Monitored] The applicant stated that the systems, structures, and components within the auxiliary building and reactor building are inspected for indications of leaks from systems containing borated water. Indications include, but are not limited to, the presence of boron crystals, pitting, and any other degradation beyond normal rust and surface discoloration that may indicate a loss of material. The staff found the parameters monitored, such as boron crystals, pitting, and other degradation, to be acceptable because they provide direct indication of leakage and potential degradation.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided in the Monitoring and Trending section below, the Fluid Leak Management Program will detect boric acid intrusion and/or loss of material due to boric acid wastage prior to loss of structure or component intended function(s). The staff found the walkdowns to be an acceptable method for identifying leakage problems and the frequency of inspection to be a reasonable time. However, the staff did determine that additional information was needed to complete its review.

By letter dated January 28, 2002, the staff requested, in RAI B.3.15-1, the applicant to describe any provisions of the program for inspecting potentially vulnerable, inaccessible locations. In its response dated March 15, 2002, the applicant stated that a review of containment systems would be conducted to ensure that all potential leak locations would be identified, whether accessible or inaccessible. This understanding of these leakage locations, whether accessible or inaccessible, was an aspect of the initial fluid leak management program when it was established in 1989. The applicant also noted that the program has since been expanded to systems containing boric acid in locations outside of containment that could possibly leak and lead to boric acid wastage. The response was found to be acceptable because the applicant adequately addressed the provision for inspecting potentially vulnerable, inaccessible locations. The applicant will be doing additional work in this area to respond to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," and NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs." These Bulletins were issued as a result of the Davis-Besse reactor vessel head wastage event, which was attributed to corrosion from boric acid leakage through cracks in the control rod drive mechanism nozzle welds.

The staff and nuclear power industry are pursuing resolution of the issues revealed by the Davis-Besse event, and the staff is evaluating potential changes to the requirements governing inspections of Alloy 600 VHP nozzles and PWR upper RV heads (specifically with respect to non-destructive examinations and the ability to detect cracking in the VHP nozzles prior to loss of material in the upper RV heads). Because these are emerging issues that have not yet been resolved, but will be resolved during the current license term, consideration of these issues is beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b). Section 3.1.3.2.2 of this SER provides a more detailed discussion of these emerging issues.

Based on its review of the Fluid Leak Management Program, the staff believes that the program provides a reasonable means of detecting aging before loss of intended function of the affected structures, systems, and components.

[Monitoring and Trending] The applicant stated that walkdowns of the auxiliary and reactor buildings are conducted at the start of each refueling outage for the purpose of identifying leakage or evidence of leakage from borated water systems. Information on all leaks (e.g., equipment, system, leakage type and rate) is captured in the fluid leak management database to facilitate trending of leakage, if necessary. The fluid leak management database is periodically reviewed to identify adverse trends and opportunities to improve maintenance, engineering, and operation practices. The staff found the applicant's approach of monitoring activities to be acceptable because it is based on methods that are sufficient to provide predictability of the extent of degradation so that timely corrective or mitigative actions are possible.

[Acceptance Criteria] The applicant described the acceptance criteria as finding the external surfaces of structures and components within the scope of the Fluid Leak Management Program, including surroundings (e.g., insulation and floor areas), to be free from pitting and corrosion, abnormal discoloration, or accumulated residues that may be evidence of leakage from proximate borated water systems. Because the degradation is detectable by visual inspection, the staff found this to be an acceptable set of acceptance criteria.

[Operating Experience] The applicant stated that the fluid leak management databases for Catawba and McGuire were searched for boric acid leaks that have been identified through the implementation of the Fluid Leak Management Program. The applicant stated that the majority of the leaks were identified as inactive, with evidence only of past leakage. No evidence of loss of material has been found on either the leaking components or on other components in the area of any identified leak. Corrective actions, which were implemented through the applicant's work management system, included cleaning the area around the leak and either tightening bolted closures or containing the leak. The applicant concluded that the frequencies of inspections have been demonstrated to be adequate to identify leaks before any loss of material is a concern, and thus before loss of component intended function(s) occurs. The staff found that the applicant has demonstrated that the Fluid Leak Management Program has been effective in managing the effects of boric acid wastage on the intended function of plant components.

3.0.3.7.3 FSAR Supplement

LRA Appendix A-1, Section 18.2.11, provides the applicant's proposed FSAR supplement describing the McGuire Fluid Leak Management Program. Appendix A-2, Section 18.2.10, provides the description of the Catawba Fluid Leak Management Program. These descriptions are consistent with the information provided in Appendix B, Section B.3.15, and are therefore found to be acceptable.

3.0.3.7.4 Conclusion

The staff has reviewed the information in Section B.3.15 of LRA Appendix B and the applicant's response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Fluid Leak Management Program will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.8 Galvanic Susceptibility Inspection

The applicant described its Galvanic Susceptibility Inspection program in Section B.3.16 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant has demonstrated that the Galvanic Susceptibility Inspection program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.8.1 Technical Information in the Application

Section B.3.16 of LRA Appendix B describes a new program the applicant intends to implement to characterize any loss of material due to galvanic corrosion from exposure to gas, unmonitored treated water, and raw water environments. Galvanic corrosion could occur in the following systems:

- condenser circulating water
- containment ventilation cooling water (McGuire only)
- diesel generator room sump pump
- exterior fire protection
- interior fire protection
- liquid radwaste (Catawba only)
- nuclear service water
- waste gas

The galvanic couples in these systems are carbon steel, cast iron, and ductile iron (anodes) coupled to copper alloys or stainless steel (cathodes) and copper alloys (anodes) coupled to stainless steel (cathode). Copper alloys are comprised of copper, brass, bronze, and copper-nickel. In galvanic couples, the loss of material occurs in the anodes.

The applicant's Galvanic Susceptibility Inspection program is a one-time inspection program that will examine a select set of carbon steel-stainless steel couples at each site using a volumetric examination technique. As an alternative, visual examination will be used if access to internal surfaces becomes available. The susceptibility and aggressiveness of galvanic corrosion is determined by the material position on the galvanic series and the characteristics of the surrounding environment. Since inspection of all couples is impractical, certain locations will be inspected where galvanic corrosion is more likely to occur. These more susceptible locations are where the materials are the farthest apart on the galvanic series surrounded by the most corrosive of the three environments identified above. For the couples noted above, carbon steel and stainless steel are the farthest apart on the galvanic series and raw water is the most corrosive environment.

3.0.3.8.2 Staff Evaluation

The staff's evaluation of the applicant's AMPs related to the Galvanic Susceptibility Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The scope of the program includes all galvanic couples exposed to gas, unmonitored treated water, and raw water environments in the systems noted above. In this program, the applicant determines acceptability of the components subject to galvanic corrosion for service during the period of extended operation. This determination will be achieved by performing inspection of selected components. The program will inspect a select set of carbon steel-stainless steel couples at each site using a volumetric examination technique. The sample will purposely contain components expected to be most susceptible to galvanic corrosion. The sample will consist of carbon steel components coupled with components made from stainless steel and exposed to a raw water environment. Since these materials are the farthest apart on the galvanic series, and in the most aggressive environment, the highest potential for galvanic corrosion is expected. The staff finds the scope of this AMP acceptable because the inspections will be of the most susceptible material and the inspection results will be applied to other couples in the systems, as appropriate.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees that the purpose of the program is to visually examine those areas within the scope of the program and take corrective action where required. Therefore, preventive or mitigative actions are not required.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the program is pipe wall thickness, as a measure of loss of material, of carbon steel-stainless steel couples exposed to raw water environments. The staff finds the parameter monitored to be acceptable because pipe wall thickness will provide a clear indication of loss of material. In addition, the techniques to be used are consistent with current industry practice and are capable of identifying pipe wall thinning, and are therefore acceptable.

[Monitoring and Trending] There are no activities in the Galvanic Susceptibility Inspection program with regard to monitoring and trending. The staff did not identify the need for such.

[Detection of Aging Effects] The applicant stated that this is a one-time inspection that will detect the presence and extent of any loss of material due to galvanic corrosion. The wall thickness inspection of the representative sample will determine loss of material due to galvanic corrosion, and assess the likelihood of the impact of this aging effect on the components in the portion of the plant included in the LRA. The staff finds this approach acceptable because it bounds galvanic corrosion rates occurring in other components in the plant and, therefore, provides meaningful detection of age-related damage caused by galvanic corrosion.

With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by June 12, 2021, at McGuire and by December 6, 2024, at Catawba. The staff finds this inspection schedule acceptable because, if present, galvanic corrosion is expected to be a slow-acting corrosion mechanism for the affected components in these systems; therefore, the staff finds the use of a one-time inspection adequate.

[Acceptance Criteria] The acceptance criterion for the program is no unacceptable loss of material that could result in a loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.16-2, additional information from the applicant regarding the acceptance criteria to be used to define "unacceptable loss of material." In its reply dated March 15, 2002, the applicant indicated that if evidence of loss of material is observed during the initial inspection, a problem report would be developed in accordance with the Problem Investigation Process defined in Nuclear System Directive 208.

The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. The applicant also indicated that criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report.

The applicant believes it is premature to specify an analysis methodology and the actual criteria or analysis methods for determining the severity of degradation and need for corrective actions to address conditions that may be identified during an inspection that will occur 15 to 20 years from now. The staff agrees with the applicant's position. Since the applicant indicated that criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions, the staff finds the applicant's response to be acceptable.

[Operating Experience] The applicant indicated that there was no operating experience for the Galvanic Susceptibility Inspection program at McGuire and Catawba. However, because of the possibility of this type of corrosion, it established a one-time inspection program. In this program, Duke will determine acceptability of the components subjected to galvanic corrosion for service during the period of extended operation. This determination will be achieved by performing inspection of selected components. The sample will purposely contain components expected to be exposed to the highest rates of galvanic corrosion. Although the Galvanic Susceptibility Inspection is a new program, with which the applicant has no operating experience, the applicant recognizes that galvanic corrosion is possible. Since the applicant will sample (as a one-time inspection) components expected to be exposed to the highest rates of galvanic corrosion, the staff finds the applicant's approach acceptable.

3.0.3.8.3 FSAR Supplement

Section 18.2.12, in Appendix A-1 of the LRA, contains the McGuire FSAR supplement describing the Galvanic Susceptibility Inspection program and Section 18.2.11, in Appendix A-2 of the LRA, contains the Catawba FSAR supplement for this program. The program descriptions are consistent with those provided in Section B.3.16 of LRA Appendix B and are therefore acceptable to the staff.

3.0.3.8.4 Conclusion

The staff has reviewed the information in Section B.3.16 of LRA Appendix B. On the basis of this review and the applicant's response to the staff's RAI, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with components subjected to galvanic corrosion will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.9 Common Heat Exchanger Activities

In Section B.3.17 of LRA Appendix B, the applicant described the performance testing and the preventive maintenance activities associated with heat exchangers in several different systems. The staff's evaluations of system-specific AMPs are provided in the following SER sections:

- component cooling system heat exchangers - Section 3.3.5.2
- containment spray system heat exchangers - Section 3.2.4.2
- diesel generator engine cooling water system heat exchangers - Section 3.3.12.2
- control area chilled water system heat exchangers - Section 3.3.8.2
- diesel generator starting air heat exchangers (Catawba only) - Section 3.3.17.2

The following Heat Exchanger Activities are characterized as common AMPs —

- Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units (McGuire only)
- Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers (McGuire only)

The staff reviewed the LRA to determine whether the applicant has demonstrated that these Common Heat Exchanger Activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff's evaluation of these common AMPs is provided in the following Sections 3.0.3.9.1 and 3.0.3.9.2.

3.0.3.9.1 Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units

The applicant described its Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program in Section B.3.17.6 of LRA Appendix B. Although this AMP is credited for monitoring aging effects of heat exchanger tubes associated with the auxiliary building ventilation system for McGuire only, it is considered a common AMP that is shared among pump motor air handling units in the containment spray, residual heat removal, and fuel pool cooling systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3). This program is applicable only to McGuire because Catawba has shutdown panel area air conditioning unit condenser tubes, tubesheets, and shells in place of the McGuire containment spray pump motor air handling unit tubes and plenum assembly.

The aging effects of the subject Catawba components include fouling and loss of material, which are managed by the Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components.

3.0.3.9.1.1 Technical Information in the Application

As described in the LRA, the purpose of the Heat Exchanger Preventive Maintenance Activities - Pump Motor Air Handling Units program is to manage loss of material and fouling of copper heat exchanger tubes that are exposed to raw water. The Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program is a new condition monitoring program that will detect the presence, and assess the extent, of material loss that can affect the pressure boundary function and will periodically clean the heat exchanger tubes to manage fouling. While fouling is managed currently by cleaning, this comprehensive program to manage both loss of material and fouling is a new plant program for license renewal.

3.0.3.9.1.2 Staff Evaluation

The staff's evaluation of the applicant's submittal on the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The scope of Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units includes the tubes in the following McGuire heat exchangers of the Auxiliary Building Ventilation System:

- containment spray pump motor air handling units
- residual heat removal pump motor air handling units
- fuel pool cooling pump motor air handling units

The staff found the scope of the program to be acceptable because it includes those components important to the system function and will allow identification of fouling which can affect the heat transfer function of the component.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss and fouling, not to prevent such loss or fouling.

[Parameters Monitored or Inspected] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program will inspect the heat exchanger tubes to provide an indication of loss of material. Fouling of the internal portions of the heat exchanger tubes exposed to raw water is managed by tube cleaning. Routine differential pressure testing determines when cleaning is required. The staff found the parameters monitored to be acceptable since the parameters evaluated and the methods used are comparable to industry practice and will result in detecting material loss before loss of component function.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided in the LRA under the Monitoring and Trending section, the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program will detect loss of material prior to loss of the component intended pressure boundary function. The program will also manage fouling prior to loss of heat transfer function. The staff's review found this acceptable, because the applicant performs non-destructive or destructive testing methods, which are standard industry methods, and the staff agrees that the program is capable of detecting and correcting aging degradation before loss of component function.

[Monitoring and Trending] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units Program involves performance of either a destructive or non-destructive examination of one of the twelve total cooling coils within the scope of the program. The examination method will permit inspection of the inside surfaces of the tubes for loss of material.

The applicant stated that the selection of the specific inspection locations will take into consideration the normal operating environments. The containment spray pump motor air handling units and the residual heat removal pump motor air handling units are normally isolated. The fuel pool cooling pump motor air handling units are normally in service and should experience the most susceptible service environment for loss of material to occur. Therefore, the cooling coils of one of the fuel pool cooling pump motor air handling units will be examined as a representative sample of the population governed by the program. Tube cleaning is performed to manage fouling of the heat exchanger tubes as determined by routine differential pressure testing. No actions are taken as part of this activity to trend inspection or test results. This new comprehensive program will be implemented following issuance of renewed operating licenses for McGuire Nuclear Station, and by June 12, 2021 (the end of the initial license of McGuire 1).

The staff's finds that the monitoring activities will allow the applicant to identify fouling and/or loss of material. The staff has reviewed the selection criteria used by the applicant to determine the appropriate sampling locations and finds the sample to be appropriate as a leading indicator for other components in the program because they will be sampling the system most likely to experience aging effects.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program is no unacceptable loss of material of the tubes that could result in a loss of the component intended function(s), as determined by engineering evaluation. The staff did not consider this an adequate acceptance criterion for the Heat Exchanger Preventive Maintenance Activities AMP. The staff requested the applicant to specify parameters with quantitative limits. The staff also noted that a similar finding was documented in SER Sections 3.0.3.9.2.2, 3.2.4.2.2, 3.3.5.2.2, 3.3.8.2.2, 3.3.12.2.2, and 3.3.17.2.2. Therefore, as it applied to this section (Section 3.0.3.9.1.2) of the SER, this issue was characterized as SER open item 3.0.3.9.1.2(a). Similar findings were characterized as SER open items 3.0.3.9.1.2(b), 3.0.3.9.1.2(c), 3.0.3.9.1.2(d), 3.0.3.9.1.2(e), 3.0.3.9.1.2(f), and 3.0.3.9.1.2(g) in Sections 3.0.3.9.2.2, 3.2.4.2.2, 3.3.5.2.2, 3.3.8.2.2, 3.3.12.2.2, and 3.3.17.2.2 of this SER, respectively.

In its response to SER open item 3.0.3.9.1.2(a), dated October 28, 2002, the applicant indicated that these heat exchanger tubes are a coil design and, therefore, are not candidates for eddy current testing. As indicated in Section B.3.17.6 of the LRA, either destructive or non-destructive examination will be performed to examine the internal surfaces of the tubes. If evidence of loss of material is observed during the initial inspection, a problem report will be initiated in accordance with the Problem Investigation Process defined in Nuclear System Directive 208. The Problem Investigation Process is a formalized process for documenting engineering evaluations of plant problems that would include the assessment of the severity of the observed degradation, the need for corrective actions, the need for further inspections of other locations, and the need for future inspections or programmatic oversight. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions. Any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. Since the applicant indicated that it would consider the ASME Code (which is endorsed by the staff through 10 CFR 50.55(a) and other pertinent factors in determining the acceptance criteria for loss of material, the staff finds the applicant's response to SER open item 3.0.3.9.1.2(a) acceptable. Therefore, open item 3.0.3.9.1.2(a) is closed.

The applicant stated that the acceptance criteria for the performance testing activities is the established differential pressure value that ensures fouling does not prevent the heat exchangers from performing their design basis function. The staff found the acceptance criteria to be acceptable, because the testing method will detect degradation of the heat exchangers and will allow corrective action to be taken before fouling can result in loss of the design function.

[Operating Experience] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program tube examination is a new activity for which there is no plant-specific operating experience. The applicant reported that there have been no age-related tube failures in any of the cooling coils within the scope of this program, as confirmed through periodic leak detection. A few tube leaks have been detected and repaired, but were determined not to be age-related. Periodic tube cleaning has been performed by the applicant in the past. Routine differential pressure testing determines when cleaning is required. This method has been effective in managing fouling of the heat exchanger tubes and will continue to be performed during the period of extended operation.

The staff finds that, although this is a new program, prior experience in periodic leak detection and other testing have provided a basis for concluding that the program will be an effective method of monitoring the components during the period of extended operation. Therefore, the staff agrees that past operating experience can be relied on to provide the basis for this new program.

3.0.3.9.1.3 FSAR Supplement

In Appendix A-1, Section 18.2.13.6, the applicant has provided a proposed FSAR supplement for the McGuire Station. This program will be applied only at McGuire. The staff has reviewed this information and finds it to be consistent with the information provided in Section B.3.17.6 of LRA Appendix B and is therefore acceptable.

3.0.3.9.1.4 Conclusion

The staff has reviewed the information in Section B.3.17.6 of LRA Appendix B. On the basis of this review and the above evaluation, and with the resolution of open item 3.0.3.9.1.2(a), the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.9.2 Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers

The applicant described its Heat Exchanger Preventive Maintenance Activities for the pump oil coolers in Section B.3.17.7 of LRA Appendix B. Although this AMP is credited for monitoring aging effects of heat exchanger tubes associated with the nuclear service water system for McGuire only, it is considered a common AMP that is shared among oil coolers for pumps associated with the charging (chemical and volume control system) and safety injection systems. The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3). This program is only applicable to McGuire because Catawba has annubars and other tubing components instead of the McGuire centrifugal charging pump bearing oil cooler tubes and speed reducer oil cooler tubes. The aging effects of the subject Catawba components include loss of material and cracking, which are managed by the Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection Program, Service Water Piping Corrosion Program, and Fluid Leak Management Program.

3.0.3.9.2.1 Technical Information in the Application

In Section B.3.17.7 of LRA Appendix B, the applicant provided a discussion of the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers. This program is to be conducted only at McGuire and is applicable only to the McGuire Nuclear Station. The applicant stated that the purpose of the program is to manage loss of material and fouling of copper-nickel heat exchanger tubes that are exposed to raw water. The Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers is a new condition monitoring program that monitors specific component parameters to detect the presence, and assess the extent, of material loss that can affect the pressure boundary function and periodically cleans the heat exchanger tubes to manage fouling. While the applicant currently manages fouling by periodic cleaning, this comprehensive program to manage both loss of material and fouling is a new plant program for license renewal.

3.0.3.9.2.2 Staff Evaluation

The staff's evaluation of the applicant's submittal of the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant stated that the scope of the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program consists of the tubes in the following McGuire heat exchangers supplied by the nuclear service water system:

- centrifugal charging pump bearing oil cooler
- centrifugal charging pump speed reducer oil cooler

- reciprocating charging pump bearing oil cooler
- reciprocating charging pump fluid drive oil cooler
- safety injection pump bearing oil cooler

The staff found the scope of the program to be acceptable because it includes those components important to the system function and will allow identification of fouling which can affect the heat transfer function of the component.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agrees with the applicant because the purpose of the program is to detect and assess the extent of material loss and fouling, not to prevent such loss or fouling.

[Parameters Monitored or Inspected] As described in the application, the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program inspects the heat exchanger tubes to provide an indication of the loss of material. Fouling of the internal portions of the heat exchanger tubes exposed to raw water is managed by routine cleaning. The staff found that because the inspections will be performed and allow for corrective actions to be taken prior to the loss of the component's function, the parameters monitored or inspected are adequate to meet the stated purpose of the program.

[Detection of Aging Effects] The applicant stated that the information provided under the Monitoring and Trending section in the LRA demonstrated that the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program will detect the loss of material prior to the loss of the component's intended pressure boundary function. The program will also manage fouling prior to the loss of the heat transfer function. The staff found that this approach is acceptable because the program is capable of identifying the aging effects prior to the loss of the component's intended function.

[Monitoring and Trending] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program will perform eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. Non-destructive testing (NDT) will be performed on 100 percent of the tubes. The staff found this one-time inspection acceptable because, following the initial inspection, the applicant will establish an appropriate frequency for follow-up inspections based on inspection results. Tube cleaning is performed to manage fouling of the heat exchanger tubes every two to three years. No actions are taken as part of this activity to trend inspection or test results. This new comprehensive program will be implemented following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license of McGuire 1).

The staff agrees that the inspection activities are capable of identifying aging effects. Because the initial 100 percent NDT inspection will provide information on the current state of all tubes in the program, the applicant will be capable of detecting and correcting any problems prior to the loss of the component's function.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers eddy current testing activity is no unacceptable loss of material of the tubes that could result in a loss of the component intended function(s), as determined by engineering evaluation. The staff did not consider this an adequate acceptance criterion for the Heat Exchanger Preventive Maintenance Activities AMP. The staff requested the applicant to specify parameters with quantitative limits. Because the same finding was identified for the Heat Exchanger Preventive Maintenance Activities — Pump Motor Air Handling Units, as documented in Section 3.0.3.9.1.2 of this SER, this issue was characterized as SER open item 3.0.3.9.1.2(b).

In its response to SER open item 3.0.3.9.1.2(b-g), dated October 28, 2002, the applicant indicated that eddy current testing is the method used to manage loss of material of the subject heat exchanger tubes. Eddy current testing is a standard industry practice used for detecting wall loss in heat exchangers, but requires careful engineering evaluation of all test results to provide the proper management of a heat exchanger. Steam generators are the only plant heat exchangers for which station technical specifications or sets of standards exist to define the flaw depth at which a tube must be plugged and removed from service.

The applicant stated that, for the low pressure, low temperature heat exchangers to which SER open items 3.0.3.9.1.2(b-g) apply, evaluating eddy current test results for "unacceptable loss of material" involves many variables such as tube material, characterization of the indication in terms of percent wall loss, rate of degradation as compared to previous indications, and the frequency of subsequent testing. Criteria such as ASME Code requirements, additional inspection results, and operating experience may be used to assess the severity of the degradation and the need for corrective actions.

The applicant further explained that eddy current testing at McGuire and Catawba is performed by a vendor who specializes in the practice. A 4-step process is used to determine if test results are acceptable and to generate the final test report. This process is described in detail in the applicant's October 28, 2002, response to this SER open item. The following is the process described by the applicant:

> (1) At the conclusion of testing of a component, the vendor's eddy current testing manager reviews the data and makes a plugging recommendation in the preliminary report based on his assessment of the damage flaws and experience with testing the component. Experience demonstrates that these specialists generally recommend evaluation at around a 70 percent wall loss range.
>
> (2) Duke then reviews the entire test data provided in the preliminary test report, including the recommendation for plugging, prior to returning the component to service. Duke evaluates the recommendations using all the information they have available. Particularly, Duke evaluates the rate of degradation based on the history of the tube. The wall loss may be deemed acceptable if the tube is showing minimal to no degradation from previous inspections. Consideration is also given to the frequency of the next inspection; if frequent inspection is performed, then a higher wall loss range may be acceptable and if less frequent inspection is performed then lower wall loss range may be unacceptable.
>
> (3) Depending on the type of tubing material and tubing damage detected with eddy current testing and possibly verified with actual tube pulled samples, a wall loss correlation may be determined as a threshold for evaluating the tube for plugging repair. Past operating experience with the type of tubing flaw may also be a very useful factor in determining the wall loss plugging threshold.
>
> (4) The loss of material experienced by these heat exchanger tubes generally manifests itself as pits. These pitting flaws are not very likely to fail heat exchanger tubing due to mechanical stress of pressure and temperature due to the shouldered nature or material reinforcement around pits. Therefore, the pitting rate as determined from past eddy current testing experience becomes the primary factor to consider when selecting tubes to remove from service to prevent later on-line tube leaks.

The applicant further stated that its experience in evaluating eddy current testing results has proven to be effective during the operation of McGuire and Catawba. Corrective actions such as tube plugging and tube bundle and heat exchanger replacement have been taken as a result of failed acceptance criteria of the subject programs. On the basis of the information provided in the applicant's October 28, 2002, open item response, the staff finds that appropriate and adequate acceptance criteria for detecting heat exchanger tube degradation from loss of material are identified for these aging management programs. Therefore, open items 3.0.3.9.1.2(b-g) are closed.

[Operating Experience] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers eddy current testing is a new activity for which there is no plant-specific operating experience. Eddy current examinations are volumetric methods accepted by the industry to be effective for detecting age-related degradation in heat exchanger tubes. The applicant stated that there have been no tube failures in any of the heat exchangers within the scope of this program, as confirmed through periodic leak detection.

The applicant has performed periodic tube cleaning in the past. Cleaning every two to three years has been effective in managing fouling of the heat exchanger tubes. The applicant has committed to continue this periodic tube cleaning during the period of extended operation.

The staff finds that, because this new program is capable of identifying loss of material or fouling in the heat exchangers included in the scope of the program, it is an acceptable method of meeting the program objectives. Although there is no past operating experience with this program, activities to inspect the condition of the tubes in the program have been conducted in the past with acceptable results. The applicant will be using methods that are widely accepted in the industry. Therefore, the staff finds this approach to be acceptable.

3.0.3.9.2.3 FSAR Supplement

In Appendix A-1, LRA Section 18.2.13.7, the applicant has provided a proposed FSAR supplement for McGuire. This program is only applicable to McGuire because the applicable comparable oil coolers at Catawba are cooled with component cooling and are managed by the Chemistry Control Program. The staff reviewed this information and finds it to be consistent with the information provided in LRA Appendix B, Section B.3.17.7, and is therefore acceptable.

3.0.3.9.2.4 Conclusion

The staff has reviewed the information in Section B.3.17.7 of LRA Appendix B. On the basis of this review and the above evaluation, and with the resolution of open item 3.0.3.9.1.2(b), the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers program will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.10 Inservice Inspection Plan

The applicant described its Inservice Inspection (ISI) Plan in Section B.3.20 of LRA Appendix B. Throughout the service life of nuclear power plants, Class 1 components and associated

Class 1 supports must meet the requirements set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in 10 CFR 50.55a(b).

Inservice examinations and system pressure tests conducted during successive 120-month inspection intervals, following the initial 120-month ISI interval, must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in 10 CFR 50.55a(b) 12 months prior to the start of the 120-month inspection interval, subject to the limitations and modifications, such as code editions and addenda, as listed in paragraph 10 CFR 50.55a(b)(2)(i).

The period of extended operation will contain the fifth and sixth ISI intervals. The ISI Plan for each interval of the renewal license period of extended operation for McGuire and Catawba will comply with 10 CFR 50.55a(g)(4)(ii) except that, if an examination required by the Code or Addenda is determined to be impractical, then the applicant will submit a relief request to the Commission in accordance with the requirements contained in 10 CFR 50.55a(g)(5)(iii) and (iv) for Commission evaluation, as required by 10 CFR 50.55a(g)(6)(i).

The Integrated Plant Assessment performed for McGuire and Catawba credited the ASME Section XI Code requirements for ISI of Class 1 components, Class 2 portions of the steam generators and associated supports as shown in Tables IWB 2500-1 and IWC-2500-1 of the 1989 Edition of ASME Section XI, including mandatory Appendices VII and VIII. Appendix VIII is in accordance with the 1995 Edition through 1996 Addenda. At present, the code of record for the McGuire and Catawba units is the 1989 Edition, no addenda, as described in the second interval ISI Plan for McGuire and Catawba.

3.0.3.10.1 Technical Information in Application

The ISI Plan is required by 10 CFR Part 50. The applicant notes that the program described in the LRA has been in use at the plants since initial licensing. The applicant states that McGuire and Catawba are currently in the second inspection interval, with more than 20 years experience at McGuire and 15 years at Catawba with the ISI Plan.

The ISI Plan includes the following inspections and activities:

- ASME Section XI, Subsections IWB and IWC (secondary side of steam generators) Inspections
- ASME Section XI, Subsection IWF Inspections
- McGuire 1 cold leg elbow
- Small-bore piping

The LRA describes the various components inspected in each of the inspections listed above. The applicant concludes that the results to date show that the ISI Plan is capable of identifying aging effects, that the continued implementation of the program provides reasonable assurance that the aging effects will be managed, and that the piping and component supports will continue to perform their intended function for the period of extended operation.

3.0.3.10.2 Staff Evaluation

The staff's evaluation of the ISI Plan as it is credited for license renewal focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions, confirmation process, and administrative controls are implemented in accordance with Code requirements through site procedures and processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining elements are discussed below.

[Scope of Program] The scope of the ISI Plan includes the following aspects:

- ASME Section XI, Subsections IWB and IWC Inspections: All Class 1 pressure-retaining components and their integral attachments are included in the scope of the ASME Section XI, Subsections IWB and IWC Inspections. In addition, Subsection IWC, Examination Categories C-A, C-B, C-C, and C-H cover the Class 2 portions of the steam generators.
- ASME Section XI, Subsection IWF Inspections: The scope is specified in IWF-1210 and includes ASME Class 1, 2, and 3 piping supports and component supports.
- McGuire 1 cold leg elbow: Reduction in fracture toughness due to thermal embrittlement can be an aging effect for certain types of cast austenitic stainless steel in locations where temperatures continuously exceed 482 ºF. As a result of an evaluation of susceptible components by the applicant, only the McGuire 1, Loop B cold leg elbow exceeds the NRC-established threshold and is susceptible to thermal embrittlement, requiring aging management for license renewal.
- Small-bore piping: Small-bore piping is defined as piping less than 4-inch nominal pipe size. This piping does not receive volumetric inspection in accordance with ASME Section XI, 1989 Edition, Examination Category B-J or B-F. Cracking has been identified as an aging effect requiring programmatic management for reactor coolant system small-bore piping for the period of extended operation. A risk-informed method to select Class 1 piping welds for inspection in lieu of the requirements specified in ASME Section XI, Table IWB-2500-1, Examination Category B-J and B-F, has been approved for use at McGuire during the third and fourth ISI intervals. The applicant plans to complete a similar review for Catawba, as documented in its FSAR supplement. This review will be performed based on WCAP 14572, Revision 1, which requires that the McGuire and the Catawba risk-informed submittals provide equivalent or better risk coverage for the risk-informed inservice inspection scope. The review will be performed before the period of extended operation begins.

The staff finds the scope of this aging management program is relatively comprehensive and includes the systems, structures, and components that are required to be included in the ASME ISI Plan. However, the staff believed that the applicant should perform a volumetric examination of a sample of small-bore Class-1 piping less than 4-inches in diameter (refer to the discussion of open item 3.0.3.10.2-1 associated with the Detection of Aging Effects element below).

[Preventive or Mitigative Actions] The applicant describes the ISI Plan as a condition monitoring program and does not include actions to prevent aging effects or mitigate aging degradation. The staff considers the ISI Plan to be a means of detecting, not preventing, aging and therefore agrees that there are no preventive actions required.

[Parameters Inspected or Monitored] Section B.3.20 of LRA Appendix B states that the following items are included in the system:

- ASME Section XI, Subsections IWB and IWC Inspections Class 1 component welds, integral attachments, piping welds, bolted closures, and supports, as well as the Class 2 pressure boundary portions of the steam generators (welds and welded attachments), are inspected for cracking and loss of material.
- ASME Section XI, Subsection IWF Inspections: All Class 1, 2, and 3 piping and component supports are inspected for loss of material.
- McGuire 1 cold leg elbow: The applicant proposes the use of an augmented inspection with elements from Code Case N-481 to manage reduction of fracture toughness by thermal embrittlement for the affected elbow during the period of extended operation.
- Small-bore piping: The applicant has been approved to use a risk-informed approach to identify risk-significant segments within the reactor coolant system and select Class 1 piping welds for inspection at McGuire and plans to submit a similar plan for Catawba.

The staff reviewed the information provided in the LRA and agrees that, because the methods used in the ISI Plan are capable of detecting loss of material in the inspected systems and components, these inspection techniques are acceptable.

[Detection of Aging Effects] The applicant stated that the ISI Plan has demonstrated the capability to detect loss of material for Class 1, 2, and 3 piping and component supports prior to loss of structure or component intended functions. The staff agreed that the program, which is consistent with current industry practice and ASME requirements, is capable of detecting aging effects and is acceptable. However, the staff believed that volumetric examination of a sample of small-bore Class-1 piping is needed to demonstrate that the effects of aging are being adequately managed. Volumetric examination techniques provide a demonstrated capability and a proven industry record to permit detection and sizing of significant cracking and flaws in piping weld and base material. The sample of affected welds selected for inspection should be based upon piping geometry, pipe size, and flow conditions, and the inspection should be performed by qualified personnel using approved station procedures. Therefore, this issue was characterized as SER open item 3.0.3.10.2-1.

By letter dated October 28, 2002, the applicant provided the following response to open item 3.0.3.10.2-1:

> As discussed in Appendix B page B.3.20-5 of the Application, Duke has proposed that aging of small-bore piping (piping less than 4-inch NPS) be managed by Risk-Informed Inservice Inspection (RI-ISI) requirements. The risk-informed approach is based on WCAP 14572 Revision 1-NP-A and consists of the following two essential elements: (1) a degradation mechanism evaluation is performed to assess the failure potential of the piping under consideration, and (2) a consequence evaluation is performed to assess the impact on plant risk in the event of a piping failure.
>
> Duke submitted a request for relief, pursuant to 10 CFR 50.55a (g), to obtain staff approval of RI-ISI for McGuire Units 1 and 2 on June 26, 2001 (just after the submittal of the license renewal application on June 13, 2001). Supplemental information in support of this request relief was provided by Duke letters dated January 11, 2002 and March 15, 2002.

RI-ISI will allow Duke to perform volumetric examinations of certain risk significant small-bore piping. Inspection locations are based on damage mechanism and consequences. Damage mechanisms considered in RI-ISI include: fatigue, stress corrosion cracking, and flow assisted corrosion/wastage. The fatigue model assumes that all failures by this mechanism result from preexisting flaws. Inputs to the model are sufficiently flexible to address low cycle fatigue attributable to normal plant transients, high cycle thermal fatigue (resulting, for example, from stratification of fluids and turbulent penetration), and high cycle vibrational fatigue. Duke letter dated January 11, 2002 to the staff identifies the specific degradation mechanisms considered for the Reactor Coolant System (NC) (entries on pages 3 of 37 and 4 of 37 of the attachment).

The NRC staff approved the use of RI-ISI on McGuire Units 1 and 2 by safety evaluation provided by letter dated June 12, 2002.

Risk informed assessment has not been completed for Catawba. Catawba is expected to have similar results and therefore should have a sample of small-bore piping that will be volumetrically examined due to future implementation of risk-informed methods.

For the reasons stated above, Duke believes that the staff concern is effectively addressed by the recently approved RI-ISI program for McGuire. A similar RI-ISI program will be implemented at Catawba which will also address volumetric examinations of a sample of small-bore Class 1 piping.

The staff identified four concerns with the applicant's program for inspecting small-bore Class 1 piping, as provided in the LRA and modified by the applicant's response to open item 3.0.3.10.2-1:

1. The staff's SE of June 12, 2002, only approved use of the RI-ISI methods of WCAP-14572 as a basis for selecting the most susceptible ASME Class 1 and 2 piping locations using a risk-informed selection process and the existing ASME Code inspection methods (the methods are specified in Section XI Table IWB-2500-1, Categories B-F and B-J for Class 1 piping, and Table IWC-2500-1, Categories C-F-1 and C-F-2 for Class 2 pipe). The exception to this was that the staff approved visual VT-2 methods as acceptable alternative inspection methods for highly risk-significant Class 1 and 2 socket welds. The current ASME Section XI inspection requirements for small-bore Class 1 piping less than 4 inches NPS are surface examinations once every 10-year ISI interval. Open item 3.0.3.10.2-1 raised the issue that current inspection methods required by Section XI for full-penetration-welded small-bore Class 1 piping that is less than 4 inches NPS may not be sufficient to detect cracking in the butt welds. The staff position is that, therefore, a one-time inspection using volumetric inspection methods should be proposed for inspection of small-bore Class 1 pipe segments that are less than 4 inches NPS and are joined using full penetration butt welds. The applicant's response to open item 3.0.3.10-2 does not provide any indication that the applicant is committed to performing volumetric examinations of the small-bore piping locations that are joined using full penetration butt welds.

2. The RI-ISI method approved in the staff's SE of June 12, 2002, does not provide assurance that any small-bore Class 1 piping locations that are joined by full penetration butt welds will be inspected volumetrically. The potential exists for the methodology to "screen out" small-bore piping based on risk information. The license renewal rule, as currently written in 10 CFR Part 54, does not allow the staff to accept the elimination of SSCs from aging management based on risk-informed arguments.

3. No RI-ISI program has been approved for the Catawba 1 and 2. Therefore, an RI-ISI approach cannot be used for the Catawba units because it is not part of the CLB for the

units. Furthermore, no commitment has been made to submit an alternative RI-ISI-based program under 10 CFR 50.55a(a)(3)(i) that would require the applicant to perform volumetric examination of small-bore piping locations that are welded with full penetration butt welds.

4. The staff's assessment and approval in the SE of June 12, 2002, approved an RI-ISI program for ASME Code Class 1 and 2 piping only for the third 10-year ISI intervals for McGuire 1 and 2. The applicant had made no commitment to resubmit the alternative for approval for subsequent 10-year ISI intervals.

The staff informed the applicant of these concerns in a letter dated November 13, 2002. On November 14, 2002, the applicant provided the following supplemental response to open item 3.0.3.10.2-1 to address the staff's concerns:

> Small-bore piping is defined as piping less than 4-inch NPS. This piping does not receive volumetric inspection in accordance with ASME Section XI, 1989 Edition, Examination Category B-J or B-F. Cracking has been identified as an aging effect requiring programmatic management for Reactor Coolant System small-bore piping for the period of extended operation.
>
> A set of susceptible small-bore piping locations will be volumetrically examined on each unit. Locations to be examined will be determined based on consideration of damage mechanisms. Damage mechanisms to be considered include fatigue, stress corrosion, and flow assisted corrosion/flow wastage. Cracking due to thermal fatigue resulting from stratification of fluids and turbulent penetration flow is an aging effect that will be addressed.
>
> The *Small-Bore Piping Examination* will be an activity within the *Inservice Inspection Plan* during the period of extended operation. Small-Bore Piping examinations will be performed during each inservice inspection interval during the period of extended operation.

The applicant's amended response to open item 3.0.3.10.2-1 and proposed changes to the small-bore piping inspection specifically address the following programmatic aspects:

- It clarifies that a set of small-bore piping joined by full penetration butt welds will be examined at each unit and that locations to be examined will be determined using consideration of damage mechanisms, including thermal fatigue, stress corrosion, and flow assisted corrosion/wastage.
- It clarifies that the small-bore piping inspection is an activity within the scope of the inservice inspection plan and that the inspection method for the examinations of the small-bore Class 1 pipe will be by volumetric examination methods.
- It clarifies that the small-bore piping inspection will be performed during the ISI interval for each unit during the period of extended operation.

By letter dated November 21, 2002, the applicant provided the following additional information to clarify how the small-bore piping examination will be implemented at McGuire and Catawba:

> The *Small-Bore Piping Examination* will be an activity within the *Inservice Inspection Plan* during the period of extended operation as most recently described in Duke letter dated November 14, 2002. In order to establish the sample of small-bore piping locations to be volumetrically inspected, Duke will first determine the population of Duke Class A piping that is less than 4-inch NPS for the unit to be inspected. This population of piping will then be reviewed by experienced engineers to determine the more likely locations that could be impacted by the various damage mechanisms described in Duke letter dated November 14, 2002. The determination will involve a review of the physical plant design such as piping layout, geometry and operating temperatures as

> well as both plant and industry operating experience that could indicate more optimum inspection locations. The set of locations selected will comprise the scope of the *Small-Bore Piping Examination* and will be identified within the Inservice Inspection plan for each station.[1]

The applicant's letter of November 21, 2002, reflects that the sample of locations for the small-bore piping inspections will be based on the locations that are evaluated as being most susceptible to age-related degradation damage mechanisms. The applicant's proposed changes to the small-bore piping inspection, as provided in the applicant's letters of November 14 and 21, 2002, ensure that a sample of small-bore Class 1 piping joined by full penetration butt welds will be volumetrically inspected each ISI interval for the McGuire and Catawba reactor units. Use of a volumetric inspection method will ensure that the inspections of the small-bore piping components will be capable of detecting cracking in the components. The applicant's supplemental responses to open item 3.0.3.10.2-1 therefore resolves the staff issues raised in its letter to the applicant dated November 13, 2002, and are acceptable. The staff considers open item 3.0.3.10.2-1 to be closed.

[Monitoring and Trending] The applicant stated that the required examinations are directed by the ISI Plan. The extent and frequency of examinations are specified in ASME Section XI. Aging effects are detected through visual examination. The complete inspection scope is repeated every 10-year inspection interval. The staff considers the ASME Code requirement to be an acceptable monitoring method and agrees that no actions need be taken as part of this program to trend inspection or test results.

[Acceptance Criteria] The applicant stated that flaws detected during examination are evaluated by comparing the examination results to the acceptance standards established in ASME Code, Section XI. Unacceptable indications require detailed analyses, repair, or replacement. The ASME Code, Section XI, acceptance standards ensure that all Service Conditions (A-D) are protected by maintaining the safety margin of the component throughout the service life of the component. When evaluating an operating component for an indication that exceeds the allowable acceptance standards established in IWB-3500 and IWC-3500, Section XI requires the use of the original safety margins for all operating conditions (i.e., normal, upset, emergency, and faulted conditions). The safety margins vary for specific cases (e.g., component, geometry, etc.) but are always consistent or conservative with respect to the original design margins. The staff accepts the flaw evaluation methodology of the Code as the industry standard and, therefore, the staff finds the management of aging effects based on the Code criteria to be acceptable.

[Operating Experience] The results of the ASME Section XI Inspections for McGuire and Catawba are submitted to the NRC. The applicant reports that McGuire and Catawba are currently in the second inspection interval and have more than 20 years at McGuire and 15 years at Catawba of operating experience with the inspection of Class 1 components, as well as the Class 2 pressure boundary portions of the steam generators. The applicant stated that the inspections that have been completed to date have revealed very few flaws that did not meet

[1] Both the staff and the applicant interpret "*most likely*" locations to be the locations that are determined to be the most susceptible to aging degradation based on damage mechanism for the small-bore nozzles.

the acceptance criteria, and that required further evaluation in accordance with ASME Code, Section XI.

The staff is aware that, during V.C. Summer refueling outage 12 (October 2000), a through-wall crack was identified in the reactor vessel hot leg piping. Specifically, the crack was located in the first weld between the reactor vessel nozzle and the "A" loop hot leg piping, approximately 3 feet from the reactor vessel and 7 degrees clockwise from the top dead center of the weld (as viewed from the centerline of the reactor vessel). The weld was fabricated from Alloy 82/182 material. The licensee's metallurgical evaluation showed the crack was axially oriented with a length about 2.5 inches and was connected to a small weep hole on the outside diameter surface of the weld. The failure mode was determined to be primary water stress corrosion cracking, and the root cause of the cracking was attributed to the presence of high residual stresses resulting from extensive repairs of the subject weld.

The staff requested the applicant to identify the locations in the McGuire and Catawba RCS piping that contain welds fabricated from Alloy 82/182 material. Additionally, the staff requested the applicant to describe the actions it planned to take to address this operating experience as it applies to McGuire and Catawba. This issue was characterized as SER open item 3.0.3.10.2-2.

In its response to open item 3.0.3.10.2-2, dated October 28, 2002, the applicant stated that the McGuire and Catawba reactor coolant system piping contains the following welds fabricated from Alloy 82/182 material:

- pressurizer surge, spray, relief, and safety nozzles weld buildup (AMR is provided in LRA Table 3.1-1, page 3.1-9, row 2)
- reactor vessel, primary inlet and outlet nozzles, buttering, and welds (AMR is provided in LRA Table 3.1-1, page 3.1-11, row 3)
- steam generator primary nozzle welds (AMR is provided in LRA Table 3.1-1, page 3.1-22, row 3)
- auxiliary feedwater nozzle safe end (Alloy 600 Safe End) (AMR is provided in LRA Table 3.1-1, page 3.1-25, row 4)
- pressurizer surge and spray nozzle thermal sleeve attachment welds, as provided in the applicant's supplemental response to open item 3.0.3.10.2-2, dated November 21, 2002

The applicant stated that the applicable V.C. Summer hot leg safe-end weld was fabricated using a field weld process and was not machined to a smooth bore nozzle configuration as was the case for the corresponding welds at McGuire 1 and 2 and Catawba 1 and 2. The applicant stated that UT examination methods cannot provide accurate results when good contact is not maintained between the UT probe and the weld surface during the examination. The applicant stated that the irregular weld surface at V.C. Summer was the contributing factor for the inability of the UT inspections to provide relevant inspection results. In contrast, the applicant noted that the corresponding welds at McGuire and Catawba were machined to smooth surfaces.

The staff agrees with the applicant that the irregularity of the weld configuration at V.C. Summer hindered the ability to maintain contact between the transducers and the weld surfaces and, thereby, impaired crack detection capability. The staff also agrees that grinding the weld crowns at McGuire and Catawba will provide for better contact between the transducers for the UT techniques and the surfaces of the welds under examination, as well as better detection of cracking.

In its response to SER open item 3.0.3.10.2-2, the applicant also stated that it is participating in the activities implemented by the EPRI Materials Reliability Project (MRP) Alloy 600 ITG, Alloy 82/182 Weld Integrity Inspection Committee to document the capability of automated UT techniques to detect inside surface-connected flaws in smooth bore nozzle configurations. The automated UT techniques were tested on mockups developed by the EPRI NDE Center in Charlotte, NC. The demonstration of the automated UT techniques (including those developed by Framatome ANP) to detect cracking in the Alloy 182/82 nozzle-to-pipe safe end welds is documented in EPRI Topical Report 1006225, "Automated Ultrasonic Inside Surface Examinations of Reactor Coolant System Alloy 82/182 Nozzle Welds Performed in Spring 2001." Framatome ANP has performed examinations of Alloy 182/82 nozzle-to-pipe safe end welds for Duke at McGuire 1 to demonstrate the effectiveness of the Framatome ANP's automated UT examination technique for McGuire 1. The applicant indicated that the automated UT examinations of the inlet and outlet nozzle safe end welds at McGuire 1 are documented in EPRI Report 1006225. The applicant indicated that similar inspections will be implemented at McGuire 2 and Catawba 1 and 2 during their 10-year ISI intervals.

The scope of the automated UT inspections performed at McGuire 1 involved the following two types of weld configurations: (1) forged stainless steel safe end Alloy 182 welds that were buttered with Alloy 82 weld material and stress relieved (applicable to McGuire 1 outlet nozzles), and (2) forged stainless steel safe ends with Alloy 182/82 welds without buttering (applicable to McGuire 1 inlet nozzles). The staff reviewed the topical report's summary of the examination results that were recorded as a result of implementation of Framatome ANP's automated UT examination technique for McGuire 1. The staff noted that the examinations at McGuire did involve documented occurrences of recordable flaw indications in the McGuire 1 RCS inlet and outlet nozzle safe end welds. This demonstrates that Framatome ANP's automated UT technology is capable of detecting recordable indications in the RCS inlet and outlet nozzles at McGuire and Catawba. All recordable indications were evaluated as being subsurface flaws that were acceptable to the acceptance standards of the ASME Boiler and Pressure Vessel Code, Section XI.

The staff notes that, although the smooth surfaces for McGuire and Catawba welds, described in the applicant's response, may improve the quality of UT examinations, they alone do not ensure that completely accurate, reliable UT examination results can be obtained. The staff is also currently assessing whether the automated UT inspection techniques developed by the EPRI Materials Reliability Project (MRP) Alloy 600 ITG, Alloy 82/182 Weld Integrity Inspection Committee (including those developed by Framatome Technologies, Inc., on behalf of the Alloy 82/182 Weld Integrity Committee) are acceptable methods for detecting PWSCC in RCS hot-leg nozzle safe-end welds fabricated from Alloy 82/182 weld materials. Therefore, the staff still considers PWSCC of the weld material to be a potential aging effect for the McGuire and Catawba RCS pipe welds identified in the applicant's response to SER open item 3.0.3.10.2-2.

The staff is assessing the generic applicability of this current operating issue and is pursuing its resolution pursuant to 10 CFR Part 50. Any required activities associated with its resolution (still under review) will be implemented by the applicant during the current operating term to ensure that the integrity of the Class 1 safe-end welds will be maintained consistent with the CLB before the period of extended operation begins. Thus, pursuant to 10 CFR 54.30, the V.C. Summer issue, as it relates to the structural integrity of the McGuire and Catawba hot-leg nozzle safe-end welds, is outside the scope of the license renewal review. Since the applicant provided the information requested in SER open item 3.0.3.10.2-2 (locations of 82/182 weld material in the RCS piping and activities to address the V.C. Summer operating experience), and since, pursuant to 10 CFR 54.30, the V.C. Summer hot leg cracking event is beyond the scope of the staff's license renewal review, open item 3.0.3.10.2-2 is closed.

For bolting, in addition to the aging management programs listed, the applicant stated that information from operating experience indicates that there are additional elements of bolting maintenance procedures that should be considered, such as personnel training, installation and maintenance procedures, plant-specific bolting degradation history, and corrective measures. The NRC captured the lessons from this experience in Bulletin 82-02, which was issued June 2, 1982, and directed each licensee to assure that these lessons were being incorporated at their plant. In its response to Bulletin 82-02, provided by letters dated August 2, 1982, and July 19, 1984, the applicant submitted the results of the in-house investigation and provided assurance that bolting maintenance practices did indeed consider these lessons learned. In summary, the applicant stated that routine maintenance practices have included use of properly trained personnel and procedural guidance to construct bolted closures. The continuation of routine maintenance practices reviewed under Bulletin 82-02 will assure aging management of mechanical closure integrity for bolted closures in the reactor coolant system.

The staff has reviewed the applicant's operating experience with the ISI Plan, as well as the information submitted in response to Bulletin 82-02. The staff considers the operating experience to be a reasonable basis on which to conclude that the ISI Plan has been effective at maintaining the intended function of the components included in the program and can reasonably be expected to do so for the period of extended operation.

3.0.3.10.3 FSAR Supplement

The FSAR supplement for McGuire, provided in Appendix A-1, Section 18.2.16, of the LRA, contains a description of the McGuire 1 cold leg elbow inspection program and the small-bore piping inspection program. The FSAR supplement for Catawba, provided in Appendix A-2, Section 18.2.15, of the LRA, contains a description of the small-bore piping inspection program. These program descriptions are consistent with the discussion provided in Appendix B of the LRA. On November 14, 2002, the applicant provided the following revised FSAR supplement summary descriptions for the small-bore piping inspection, as provided in Appendix A-1, Section 18.2.16, of the LRA (for McGuire), and in Appendix A-2, Section 18.2.15, of the LRA (for Catawba):

> Small-bore piping is defined as piping less than 4-inch NPS. This piping does not receive volumetric inspection in accordance with ASME Section XI, 1989 Edition, Examination Category B-J or B-F. Cracking has been identified as an aging effect requiring programmatic management for Reactor Coolant System small-bore piping for the period of extended operation.
>
> A set of susceptible small-bore piping locations will be volumetrically examined on each unit. Locations to be examined will be determined based on consideration of damage mechanisms. Damage mechanisms to be considered include fatigue, stress corrosion, and flow assisted corrosion/flow wastage. Cracking due to thermal fatigue resulting from stratification of fluids and turbulent penetration flow is an aging effect that will be addressed.
>
> For McGuire, *Small-Bore Piping Examinations* will be performed during each inservice inspection interval during the period of extended operation following issuance of renewed operating licenses for McGuire Nuclear Station.

For Catawba, *Small-Bore Piping Examinations* will be performed during each inservice inspection interval during the period of extended operation following issuance of renewed operating licenses for Catawba Nuclear Station.

The applicant's proposed changes to the FSAR supplement summary descriptions for the small-bore piping inspection address the clarifications in the applicant's supplemental response to open item 3.0.3.10.2-1, dated November 14, 2002, and specifically address the following programmatic aspects:

- They clarify that a set of small-bore piping joined by full penetration butt welds will be examined at each unit and that locations to be examined will be determined using consideration of damage mechanisms, including thermal fatigue, stress corrosion, and flow assisted corrosion/wastage.
- They clarify that the small-bore piping inspection is an activity within the scope of the inservice inspection plant and that the inspection method for the examinations of the small-bore Class 1 pipe will be by volumetric examination methods.
- They clarify that the small-bore piping inspection will be performed during the ISI interval for each unit during the period of extended operation.

The staff concludes that these proposed changes to the FSAR supplements for the small-bore piping inspection are acceptable because they indicate that the applicant will monitor for cracking in small-bore Class 1 piping joined by full penetration butt welds through the periods of extended operation for the McGuire and Catawba units using inspection methods that are capable of detecting cracks in the components.

3.0.3.10.4 Conclusions

The staff has reviewed the information provided in Section B.3.18 of LRA Appendix B, and the summary description in the FSAR supplement in Appendix A of the LRA. On the basis of this review and the above evaluation, and with the resolution of open items 3.0.3.10.2-1 and 3.0.3.10.2-2, the staff finds that there is reasonable assurance that the effects of aging associated with the Class 1 pressure retaining components, Class 2 pressure boundary portions of the steam generators, and Class 1, 2, and 3 piping and component supports will be adequately managed, such that the intended function will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.11 Inspection Program for Civil Engineering Structures and Components

The applicant described its Inspection Program for Civil Engineering Structures and Components for McGuire and Catawba in Section B.3.21 of LRA Appendix B. The LRA credits this inspection program with assessing the ongoing, overall condition of the buildings and structures, and with identifying any ongoing degradation, through a visual inspection process. The program monitors and assesses the condition of structures affected by aging, which may cause loss of material, cracking, and change of material properties. The staff reviewed the application to determine whether the applicant has demonstrated that the program will adequately manage aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.11.1 Technical Information in the Application

Section B.3.21 of LRA Appendix B describes the Inspection Program for Civil Engineering Structures and Components as an existing aging management program that provides for periodic visual inspections to monitor the condition of structures and the exposed external surfaces of mechanical components within the structures. McGuire has the following monitored structures:

- auxiliary building structures (including the control building, diesel generator buildings, fuel buildings, main steam doghouses)
- reactor buildings (including internal structures and station vents)
- standby nuclear service water intake/discharge strictures
- standby shutdown facility
- condenser cooling water intake structure (fire pump rooms only)
- turbine building (including service building)
- yard structures (including refueling water storage tank and reactor make-up water storage tank foundations, refueling water storage tank missile wall, and trenches)

Catawba has the following monitored structures:

- auxiliary building structures (including the control complex, diesel generator buildings, doghouses, fuel buildings, fuel pools)
- nuclear service water (NSW) and standby nuclear service water (SNSW) structures (including NSW and SNSW pump structure, NSW intake structure, SNSW discharge structures, SNSW intake structure, and SNSW pond outlet)
- reactor buildings (including station vent, internal reactor building structures, and containment recirculation sump screen assembly)
- standby shutdown facility
- turbine building (including service building)
- yard structures (including low pressure service water intake structure, refueling water storage tank foundation and missile shield, yard drainage system, and trenches)

The Inspection Program for Civil Engineering Structures and Components is a condition monitoring program credited with managing the following aging effects for the period of extended operation:

- loss of material due to corrosion for exposed surfaces of steel components, including anchorage/embedments; cable tray and conduit supports; checkered plates; equipment component supports; expansion anchors; flood curbs, flood, pressure, and specialty doors; HVAC duct supports; instrument line supports; instrument racks and frames; lead shielding supports; metal roof (McGuire only); metal siding; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates and trusses; sump screens; and the unit vent stack
- cracking of masonry block walls
- change in material properties due to leaching of concrete walls and roofs
- loss of material and cracking for reinforced concrete beams, columns, and walls for the nuclear service water structures and low pressure service water intake structure (Catawba only)
- cracking and change in material properties of elastomeric flood seals (Catawba only)

- loss of material of composite roofing
- loss of material of exposed external surfaces of mechanical components
- loss of material of the steel components of the yard drainage system (Catawba only)

The LRA states that the Inspection Program for Civil Engineering Structures and Components is applicable in meeting the regulatory requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

3.0.3.11.2 Staff Evaluation

The staff's evaluation of the Inspection Program for Civil Engineering Structures and Components focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The staff finds that the structures and components monitored by the Inspection Program for Civil Engineering Structures and Components, as listed in Section B.3.21 of LRA Appendix B, cover the scope of license renewal as identified in Section 2.4 of the LRA. The staff finds that the scope of the program is acceptable since it includes a walkdown inspection of all structures and components within the scope of license renewal.

[Preventive and Mitigative Actions] There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

[Parameters Inspected or Monitored] The Inspection Program for Civil Engineering Structures and Components inspects the structures and the exposed external surfaces of mechanical components within them for the following:

- concrete — spalling, cracking, delaminations, honeycombs, water in-leakage, chemical leaching, peeling paint, or discoloration
- masonry walls — significant cracks in joints, unsealed penetrations, missing or broken blocks, or separation from supports
- structural steel — corrosion, peeling paint, beam/column deflection, loose or missing anchors/fasteners, missing or degraded grout under base plates, twisted beams, and cracked welds
- equipment foundations — settlement, cracked concrete
- equipment supports — cracked concrete, loose connections, corroded steel
- cable tray supports — loose connections, corrosion, distortion, and excessive deflection
- roof systems — structural integrity, deteriorated penetrations (i.e., drains, vents, etc.), signs of water infiltration, cracks, ponding, and flashing degradation
- seismic gaps: presence of gaps
- siding — structural integrity and visible damage

- windows/doors: missing panes, cracks, deteriorated glazing, broken or cracked frames, missing or damaged hardware, and seal integrity
- trenches — cracks, mis-alignment or damage of covers (may spot check trenches by removing covers and inspecting walls and bottoms for cracks)
- earthen structures/dams — erosion, settlement, slope stability, seepage, drainage systems, integrity of riprap, and environmental conditions
- mechanical components — loss of material for exposed external surfaces (program will be enhanced to add this)
- yard drainage system — loss of material of steel components (program will be enhanced to add this for Catawba only)

The above list identifies aging mechanisms that may potentially lead to the aging effects of loss of material, cracking, and change in material properties for concrete structural components. In its November 14, 2002, supplemental response to open items 3.5-1 and 3.5-3, the applicant credited the Inspection Program for Civil Engineering Structures and Components to monitor these three aging effects for concrete structural components.

The staff finds the above parameters, such as cracking and spalling of concrete and corrosion of steel, acceptable because they are directly related to the degradation of civil structures and components, and visual inspections are effective and adequate to detect such conditions.

[Detection of Aging Effects] The aging effects that are managed by the Inspection Program for Civil Engineering Structures and Components monitoring program are identified through visual inspections. The LRA states that each structure or component is inspected from the interior and exterior where accessible. Whenever normally inaccessible areas are made accessible (i.e., by excavation or other means), an inspection is performed and the results are documented as part of the program. The LRA also states that inspections are performed by a team of at least two people. Inspectors are qualified by appropriate training and experience and approved by responsible plant management.

By letter dated January 28, 2002, the staff asked, in RAI B.3.21-1, the applicant to describe the qualification and required experience of the inspector. In its response dated March 11, 2002, the applicant stated that the qualifications of the inspector are documented in McGuire and Catawba site documents. The applicant stated that the inspectors should be civil/structural engineering graduates with at least 4 years experience in evaluation of inservice structures. The staff finds that degreed civil/structural engineers with at least 4 years experience in evaluating inservice structures are adequately qualified and sufficiently experienced.

[Monitoring and Trending] With respect to an inspection frequency, the application states that the Inspection Program for Civil Engineering Structures and Components is nominally performed every 5 years with the exact schedule being established with consideration of refueling outages for each unit. The interval may be increased to a nominal 10-year frequency with appropriate justification based on the structure, environment, and related inspection results. The applicant's operating experience to date supports the continuation of a 5-year frequency for inspections. Furthermore, the staff finds that the 5-year frequency is consistent with industry experience and is, therefore, acceptable. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

[Acceptance Criteria] The LRA states that the acceptance criteria are no unacceptable visual indications of loss of material, cracking, or change of material properties for concrete, and loss of material for steel, as identified by the accountable engineer. Acceptable structures or components are those which are capable of performing their intended function(s) until the next scheduled inspection and are considered to meet the requirements contained in 10 CFR 50.65(a)(2). Unacceptable structures or components are those that are either (1) damaged or degraded such that they are not capable of performing their intended function, or (2) degraded to the extent that, if uncorrected before the next normally scheduled inspection, the structure or component might not perform its intended function.

In its March 11, 2002, response to RAI B.3.21-1, the applicant stated that the qualifications of the inspector are documented in McGuire and Catawba site documents. The applicant stated that the inspectors should be civil/structural engineering graduates and registered professional engineers with at least 4 years experience in evaluation of inservice structures. The applicant further stated that the qualifications of the inspector are documented in McGuire and Catawba site documents and that the oversight of the training and qualification of the accountable engineer is governed by the Duke Quality Assurance Topical Report. The staff finds that degreed civil/structural engineers with at least 4 years experience in evaluating inservice structures are adequately qualified and sufficiently experienced.

By letter dated January 28, 2002, the staff requested, in RAI B.3.21-2, the applicant to describe the criteria for (1) assessing the severity of the observed degradations, and (2) determining whether corrective actions are necessary. In its response dated March 11, 2002, the applicant stated that the acceptability of a structure is based on whether the accountable engineer determines that the structure is capable of performing its intended function(s) and that the accountable engineer will assess the severity of the degradation and determine whether corrective action is necessary. The applicant also stated that the NRC Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," described the acceptability for structural condition monitoring and capability of performing the intended function(s). The applicant further stated that the accountable engineer will use guidance provided in codes and standards, such as NEI 96-03, "Industry Guideline for Monitoring Structures," NRC Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and ACI 349.3, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," to examine and assess the condition of a structure. The staff considers the applicant's response acceptable.

The staff finds that the acceptance criteria specified above are adequate to ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] The LRA states that previous inspections for McGuire noted several minor degraded conditions; however, the conditions did not adversely affect the ability of the structures or components to perform their intended functions. All findings have been addressed by the corrective action program or by station work requests. Items that were noted that required additional investigation, repair, or other corrective actions included missing grout under base plates; degraded coatings on steel, concrete, and pipe supports; minor corrosion of steel; deterioration of expansion joints; and minor cracking and spalling of concrete. Corrective actions included repair or replacement of the affected structure or structural component.

The application states that previous inspections for Catawba revealed no serious degradation or condition that would adversely affect the ability of the structures or components to perform their intended functions. Items that required additional investigation, repair, or other corrective actions included missing grout under base plates; degraded coatings on steel, concrete, and block walls; minor corrosion of steel; deformed metal trench covers; and hairline cracking and leaching of concrete. Corrective actions included repair or replacement of the affected structure or structural component.

The staff finds that the applicant's operating experience indicates that the structural monitoring program has effectively maintained the integrity of the structures and components and that the effects of aging will be adequately managed during the period of extended operation.

3.0.3.11.3 FSAR Supplement

The staff reviewed the FSAR supplements in Section 18.2.17 of LRA Appendix A-1 and Section 18.2.16 of LRA Appendix A-2 for McGuire and Catawba, respectively, and found that the description of the Inspection Program for Civil Engineering Structures and Components is consistent with Section B.3.21 of LRA Appendix B. However, the FSAR supplements did not include reference to several of the important industry codes and standards discussed in the applicant's March 11, 2002, response to the staff's RAI. The applicant was requested to update the FSAR supplement to incorporate those standards and guidelines. This issue was characterized as SER open item 3.0.3.11.3-1. In its response dated October 2, 2002, the applicant provided an update of the FSAR supplements for McGuire and Catawba. These updates included references to NRC Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants," and ACI 349.3, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," which were included in the applicant's response to RAI B.3.21-2. Therefore, open item 3.0.3.11.3-1 is closed.

3.0.3.11.4 Conclusions

The staff reviewed Section B.3.21 of LRA Appendix B, the summary description in Appendix A of the LRA, and the applicant's March 11, 2002, response to the staff's RAIs. On the basis of this review and the above evaluation, the staff concludes that the applicant has demonstrated that the aging effects managed by the Inspection Program for Civil Engineering Structures and Components will be adequately managed so that there is reasonable assurance that the structures and components covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.12 Liquid Waste System Inspection

The applicant described its Liquid Waste System Inspection program in Section B.3.22 of LRA Appendix B. The applicant credits this program with managing the potential aging of liquid waste systems components that are within the scope of license renewal. The inspection activity monitors for loss of material and cracking. The staff reviewed Section B.3.22 of LRA Appendix B to determine whether the applicant has demonstrated that the liquid waste system inspection activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.12.1 Technical Information in the Application

Section B.3.22 of LRA Appendix B states that the purpose of the Liquid Waste System Inspection program is to characterize any loss of material and cracking of system components within the scope of license renewal that are exposed to unmonitored borated, treated, and/or raw water environments. The program is credited with managing the potential aging of the following systems:

- component cooling system (McGuire only) — stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system
- liquid waste recycle system (McGuire only) — stainless steel components exposed to an unmonitored borated water environment
- liquid radwaste system (Catawba only) — stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment

The Liquid Waste System Inspection detects aging effects through a combination of volumetric and/or visual examination. For the McGuire component cooling system, one of the four heat exchangers associated with the waste evaporator will be inspected. For the McGuire liquid waste recycle system and the Catawba liquid radwaste system, a combination of volumetric and visual examination will be performed for sample population of components chosen based on conditions likely to cause a more corrosive environment. This is a one-time inspection activity. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken.

The applicant concluded that implementation of this program will adequately verify that the components will continue to perform their intended function(s) for the period of extended operation.

3.0.3.12.2 Staff Evaluation

The staff's evaluation of the Liquid Waste System Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.22 of LRA Appendix B identifies the structures and components that credit the Liquid Waste System Inspection activities for managing the potential aging effects of loss of material and cracking as follows:

- component cooling system (McGuire only) — stainless steel waste evaporator package exposed to an unmonitored treated water environment of the liquid waste recycle system
- liquid waste recycle system (McGuire only) — stainless steel components exposed to an unmonitored borated water environment
- liquid radwaste system (Catawba only) — stainless steel components exposed to an unmonitored borated water, unmonitored treated water, or a raw water environment; carbon steel and cast iron components exposed to a raw water environment

The scope covers the in-scope components that are exposed to the liquid waste system environments; therefore, this is acceptable to the staff.

[Preventive Actions] There are no preventive actions taken as part of this program, and the staff did not identify the need for any preventive actions.

[Parameters Monitored or Inspected] Section B.3.22 of LRA Appendix B identifies loss of material and cracking as the parameters that can be detected by volumetric inspection of stainless steel components in the component cooling system (McGuire only), liquid waste recycle system (McGuire only), and the liquid radwaste system (Catawba only). As an alternative, visual examination will be used should access to internal surfaces become available. Because these inspection techniques can be used to identify the degraded conditions noted by the applicant, they are acceptable to the staff.

[Detection of Aging Effects] Section B.3.22 of LRA Appendix B states that volumetric and/or visual inspection will detect loss of material and cracking for the components. The use of volumetric and/or visual inspection is considered by the staff to be a reasonable means of detecting these aging effects before the loss of intended function, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.22 of LRA Appendix B states that the one-time inspections will be performed as follows:

- For the McGuire component cooling system, one of the four heat exchangers associated with the waste evaporator will be inspected.
- For the McGuire liquid waste recycle system and the Catawba liquid radwaste system, a combination of volumetric and visual examination will be performed for a sample population of components chosen based on conditions likely to cause a more corrosive environment.

By letter dated January 28, 2002, the staff requested, in RAI B.3.22-1, additional information related to the criteria that will be used to select the areas that are inspected. In its response dated March 15, 2002, the applicant stated that the selection criteria will include such items as component orientation, operating temperature, proximity to hot equipment, and previous operating experience. The staff finds the applicant's response reasonable and acceptable.

Section B.3.22 of LRA Appendix B states that no actions are taken as part of the program to trend the inspection results. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspection will be performed and/or corrective action will be taken. Since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.22 of LRA Appendix B states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.22-2, the applicant to describe the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant indicated that criteria will be based on ASME Code requirements, results from additional inspections, and operating experience, the staff finds the applicant's response reasonable and acceptable.

[Operating Experience] Section B.3.22 of LRA Appendix B states that the Liquid Waste System Inspection is a one-time inspection for which there is no operating experience. The staff finds this reasonable and acceptable.

3.0.3.12.3 FSAR Supplement

The staff reviewed Section 18.2.18 of LRA Appendix A-1 for McGuire, and Section 18.2.17 LRA Appendix A-2 for Catawba. The staff finds that the summary description is consistent with the LRA and is acceptable.

3.0.3.12.4 Conclusions

The staff has reviewed the information provided in Section B.3.22 of LRA Appendix B, the summary description of the Liquid Waste System Inspection in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that the Liquid Waste System Inspection will adequately manage the aging effects such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.13 Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection

The applicant described its Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection program in Section B.3.24.1 of LRA Appendix B. The applicant credits this program to manage aging effects of loss of material and cracking that could lead to loss of pressure boundary function for the following systems: condenser circulating water system, diesel generator fuel oil system, fire protection system (internal and external), nuclear service water system, and standby shutdown diesel system. The activities are intended to manage loss of material and cracking of internal and external surfaces by maintaining the integrity of the coatings. The staff reviewed Section B.3.24.1 of LRA Appendix B to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.13.1 Technical Information in the Application

In Section B.3.24.1 of LRA Appendix B, the applicant has described the activities associated with the Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection program. The program is credited for the following two purposes for license renewal:

1. Management of the loss of material of the internal surfaces of the large diameter intake and discharge piping in the condenser circulating water system. The internal carbon steel surfaces of the large diameter intake and discharge piping in the condenser circulating water system are coated to prevent the raw water environment from contacting the internal surfaces. Continued presence of an intact coating precludes loss of material of the internal surfaces of the carbon steel intake and discharge piping. This program will periodically check the condition of the coating and look for coating degradation.

2. Management of the loss of material and cracking of the external surfaces of components in the underground environment by providing symptomatic evidence of the condition of the piping external surfaces. The external surfaces are coated with a coal tar epoxy that prevents the underground environment from contacting the external surfaces. Continued presence of an intact coating precludes loss of material and cracking of components whose external surfaces are exposed to the underground environment. Inspection of the internal surfaces will provide symptomatic evidence of the condition of the external surfaces of buried components. This inspection is described by the applicant as a condition monitoring program.

The program is applicable to the internal surface of the intake and discharge piping of the condenser circulating water system. The program is also applicable to components exposed to the underground environments in the following McGuire and Catawba systems:

- diesel generator fuel oil system
- exterior fire protection
- interior fire protection (Catawba only)
- nuclear service water system
- standby shutdown diesel system

3.0.3.13.2 Staff Evaluation

The staff's evaluation of the Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant defines the scope of the Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection program as the internal surface of the intake and discharge piping of the condenser circulating water system. The program is also applicable to components exposed to the underground environments in the following McGuire and Catawba systems:

- diesel generator fuel oil system
- exterior fire protection
- interior fire protection (Catawba only)
- nuclear service water system
- standby shutdown diesel system

During its review of the program, the staff noted that the various elements of the aging management program addressed only the condenser piping with no reference to the other systems listed as being within the program scope. By letter dated January 28, 2002, the applicant was requested, in RAI B.3.24-1, to describe program implementation and operating experience for the other systems within the scope of the program, which may consist of smaller diameter piping. In its response dated March 15, 2002, the applicant stated that, during plant construction, all buried components were coated, wrapped, and backfilled in a consistent manner specified by engineering. The applicant further stated that inspection of the circulating water piping results in approximately 80 percent of the total buried surface area being inspected by this program. The results of the inspections will be applied to the remaining 20 percent of surface area residing in the other systems included in the program scope. The staff found the applicant's program ineffective at revealing degradation of the external pipe surface before the component pressure boundary is breached and leakage occurs. The staff believed that the applicant should propose an activity to verify that the external surfaces of buried components are not degrading based upon some sampling assessment of most vulnerable locations. This issue was characterized as SER open item 3.0.3.13.2-1.

After the SER with open items was issued, the staff reconsidered its assessment of the proposed program. In an electronic correspondence dated September 23, 2002 (ADAMS Accession No. ML023300265), the staff notified the applicant that open item 3.0.3.13.2-1 was considered resolved for the following reasons:

1. Corrosion of the outside surface of a buried pipe occurs at locations where the coating is damaged. Since this can happen anywhere along the pipe, the whole length of the pipe would need to be excavated to obtain meaningful information. However, this is not practical.
2. If a leak develops due to corrosion of the outside of a pipe (due to damage of the outside coating), the inside coating would also exhibit signs of damage. Therefore, inspection of the inside coating will reveal the location of the leak.
3. The degree of degradation of the inside coating can give some idea on the condition of the outside coating.

Additionally, the sample of internal pipe to be inspected consists of about 90 percent of the population of piping governed by the Condenser Circulating Water System Internal Coating Inspection program. This significant sample size should yield valid, reliable results with a high degree of confidence. The staff found a similar inspection program for Oconee acceptable.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff considers the inspections to be a means of detecting, not preventing, aging and agrees that there are no preventive actions required.

[Parameters Monitored or Inspected] The applicant stated that the parameters inspected include the internal coatings of the condenser circulating water system piping for chipping, peeling, blistering, and missing coating, as well as signs of corrosion of the underlying carbon steel. By letter dated January 28, 2002, the staff requested, in RAI B.3.24-2, the applicant to discuss what special measures will be applied to facilitate coating inspection for any areas of pipes which may be obscured by deposits, and to describe the criteria for assessing the severity of observed degradations and determining when corrective action is necessary. In its response dated March 15, 2002, the applicant stated that the areas inspected by this activity are normally in service during plant operation and as a result, debris or sediment on the bottom of the pipe has not been observed. The applicant stated that any debris and sediment that obscures the coating will be removed prior to inspection.

Because visual inspection can detect damage to protective coatings and also can provide symptomatic evidence of damage to external coating, the staff finds the parameters are appropriate and capable of identifying the effects of aging degradation.

[Detection of Aging Effects] The applicant stated that the program will visually inspect the internal coatings of the intake and discharge piping for chipping, peeling, blistering, and missing coating, as well as signs of corrosion of the underlying carbon steel. The staff disagreed with the applicant and considered inspection of the internal pipe surfaces to be inadequate for monitoring degradation of the external surfaces of buried components (piping and tanks) so that corrective action can be taken before a failure (pitting and leakage) occurs. This issue was characterized as SER open item 3.0.3.13.2-1. This open item was subsequently resolved (see the staff's evaluation of the Scope of Program attribute in preceding paragraphs within this SER section).

[Monitoring and Trending] The applicant stated that the program will visually inspect the internal coatings of the intake and discharge piping every 5 years for coating degradation. Although the external surfaces of the piping are not accessible, externally generated through-wall pits will be revealed through the observance of blistering, peeling, or missing coatings, as well as signs of corrosion of the underlying pipe and in-leakage of soil or groundwater. The applicant stated that no actions are taken as part of this activity to trend inspection results.

Based on the staff's review of the application and responses to the staff's RAIs, the staff disagreed with the applicant and considered inspection of the internal pipe surfaces to be inadequate for monitoring degradation of the external surfaces of buried components (piping and tanks) so that corrective action can be taken before a failure (pitting and leakage) occurs. This issue was characterized as SER open item 3.0.3.13.2-1, but subsequently was resolved (see the staff's evaluation of the Scope of Program attribute in preceding paragraphs within this SER section).

[Acceptance Criteria] The applicant described the acceptance criteria as "no visual indications of coating defects" that have led to corrosion of the underlying carbon steel surfaces as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in

RAI B.3.24-3, the applicant to better describe the criteria to be applied. In its response dated March 15, 2002, the applicant indicated that if the inspections identify indications of coating defects, the conditions will be evaluated using the corrective action process. Criteria such as wall loss of the underlying metal, service life of the coating, root-cause analysis of the coating failure, and operating experience could be used to assess the severity of the degradations and the need for corrective actions. The staff finds the response to be acceptable and agrees that because the visual inspections are capable of detecting degradation of component surfaces, and the approach is consistent with industry practices, the acceptance criteria are acceptable to the staff.

[Operating Experience] The applicant stated that one complete inspection has been performed on the McGuire intake and discharge piping, including the low-level intake piping from Cowans Ford Dam through the low-level intake structure to the main intake, within the last 5 years. The applicant reported that the internal coating was observed to be in good condition with random minor defects and corrosion. The applicant reported that the condenser circulating water system intake and discharge piping has experienced two leaks, one a crack in a weld near the low-level intake pumps, which the applicant identified as being due to one or two water hammer events. The applicant also found a pinhole during a visual inspection of the low-level intake piping. The applicant reported that the diameter of the pinhole was larger on the outside diameter than the inside diameter, indicating that the corrosion initiated on the external surface of the pipe. The applicant repaired the pinhole with a steel pipe plug, and did not inspect the external surface of the pipe.

At Catawba, the applicant enters the condenser circulating water system every outage for blasting and recoating and/or a walkdown of areas that are not recoated. The applicant is performing this work because the original interior coating was not properly applied and is failing. In performing these recoating and walkdown inspections, the applicant has not identified any through-wall pits originating from the exterior of the pipe. Upon completion of the recoating work, it is the applicant's stated intent that Catawba will go to a 5-year inspection frequency.

During the Catawba 1 outage in the fall of 2000, the applicant cleaned piping in the nuclear service water system to remove the fouling buildup from the pipe walls. Internal inspection of accessible areas after the cleaning discovered a row of small through-wall pits. The applicant excavated the pipe and an examination of the external coating revealed that the coating had been cut during construction, allowing the underground environment to contact the external surface. Except for the cut, the applicant noted that the external coating was in good shape. The applicant has also identified other instances of externally generated through-wall leaks of buried components that have been attributed to construction-related damage.

The staff finds that the applicant's operating experience with the Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection indicates that the activities are effective in managing loss of material of the piping and tanks by maintaining the effectiveness of the internal coatings. In the case of the buried piping, the staff found the applicant's program ineffective at revealing degradation of the external pipe surface before the component pressure boundary is breached and leakage occurs. The staff believed that the applicant should propose an activity to verify that the external surfaces of buried components are not degrading, based upon some sampling assessment of most vulnerable locations. This issue was characterized as SER open item 3.0.3.13.2-1, but subsequently was resolved (see the staff's evaluation of the Scope of Program attribute in preceding paragraphs within this SER section).

3.0.3.13.3 FSAR Supplement

Section 18.2.20 of LRA Appendix A-1, and Section 18.2.19 of LRA Appendix A-2, contain proposed new UFSAR sections for McGuire and Catawba, respectively. The staff reviewed this material and finds it to be consistent with the material provided in Appendix B. Therefore, the FSAR supplement provides an acceptable summary description of this aging management program.

3.0.3.13.4 Conclusion

The staff reviewed the information provided in Section B.3.24.1 of LRA Appendix B, the summary description in the FSAR supplement in Appendix A of the LRA, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of this review and the above evaluation, and with the resolution of open item 3.0.3.13.2-1, the staff finds that there is reasonable assurance that the aging effect of loss of material of the internal carbon steel piping and components within the scope of the program will be adequately managed, such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.14 Selective Leaching Inspection

The applicant described its AMR of the Selective Leaching Inspection program in Section B.3.28 of LRA Appendix B. This program aims to verify the integrity of components made of brass and cast iron that are exposed to raw water environments that could cause selective leaching of these components such that they may lose their pressure boundary function in the period of extended operation. The staff reviewed the application to determine whether the applicant has demonstrated that the Selective Leaching Inspection program will adequately manage the applicable effects of aging in the plant during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.14.1 Technical Information in the Application

In Section B.3.28 of LRA Appendix B, the applicant describes a new program that will be implemented to determine the acceptability of the brass and cast iron components exposed to selective leaching in raw water environments. These types of environments exist in the McGuire and Catawba Nuclear Stations and affect brass and cast iron components in the following systems:

- conventional wastewater treatment (McGuire only)
- diesel generator room sump pump (McGuire only)
- exterior fire protection
- groundwater drainage (McGuire only)
- interior fire protection
- nuclear service water (McGuire only)

The proposed Selective Leaching Inspection program will provide a one-time inspection of the affected components. It will consist of inspecting a select set of cast iron pump casings to determine whether loss of material due to selective leaching is occurring, and whether it will cause concern for the period of extended operation. The applicant stated that Brinnell hardness checks will be used to determine if the phenomenon is occurring, and if it is, an engineering evaluation will be initiated to determine the acceptability of the affected components for further service. The Selective Leaching Inspection also includes the performance of a Brinnell hardness test or an equivalent test on a sample of brass valves in the interior fire protection system at each site.

3.0.3.14.2 Staff Evaluation

The staff's evaluation of the Selective Leaching Inspection program focused on how the program managed aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program. The staff's evaluation of the applicant's quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant stated that uncertainty exists as to whether long-term exposure to raw water environments could cause loss of material due to selective leaching in brass and cast iron components such that they may lose their pressure boundary function in the period of extended operation. Therefore, the purpose of the Selective Leaching Inspection is to characterize loss of material (if any occurs) due to selective leaching of system components exposed to raw water environments. The applicant indicated that the scope of the Selective Leaching Inspection program includes brass and cast iron components exposed to raw water in the systems listed above. The staff found the program scope to be acceptable because the information in the application is comprehensive and includes the systems and components that are subject to the applicable aging effects of selective leaching.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent or mitigate aging degradation. The staff considers inspection activities to be a means of detecting, not preventing, aging and therefore, agrees that there are no preventive actions required.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the Selective Leaching Inspection is the hardness of the wetted surface of cast iron pump casings and brass valve bodies. The applicant described selective leaching as the dissolution of one metal in an alloy at the metal surface, which leaves a weakened network of corrosion products that is revealed by a Brinnell hardness check or equivalent test as a reduction in material hardness. By letter dated January 28, 2002, the staff asked, in RAI B.3.28-1, the applicant to provide the basis for concluding that the inspection of a single pump casing and a brass valve body in the exterior fire protection system at each site will be indicative of the state of selective leaching in all cast iron and brass components in all raw water systems. Also, in RAI B.3.28-2, the applicant was asked to describe the analyses or evaluations that will be used to determine the sample size for the valve inspections.

In its response dated March 15, 2002, the applicant stated that specific material types of gray cast iron and yellow brass are susceptible to loss of material due to selective leaching. The applicant was unable to confirm, from vendor documents, that the selected components were not constructed of gray cast iron. Since the aging effect could not be absolutely ruled out, the applicant considered the inspection to be warranted. The applicant stated that it believed that the environment in the exterior fire protection system pump casings is the most aggressive for promoting selective leaching, bounds the environments of the other pump casings, and is equivalent to the environment of the valve bodies. The applicant stated that due to the small number of components involved, and the likelihood that the components are not constructed of gray cast iron, the applicant believed that inspection of one pump casing at each site bounds the other components.

With regard to valves, the applicant stated that the total number of brass valves exposed to raw water will be determined prior to the inspection. A subset for inspection will be determined by focusing on those valves exposed to low-flow or stagnant conditions. This subset may be further narrowed by component geometry/location, component operating experience, length of service, accessibility, and radiological concerns. The information in the application and the responses adequately addressed the staff's concerns. The staff concludes that the inspection of a single pump and the valve sample size will be representative of selective leaching in other raw water systems. The staff found that the inspections will be capable of detecting the effects of leaching, and that the inspection methods are consistent with current industry practice and will allow the applicant to take corrective action prior to loss of component function; therefore, the staff found the parameters inspected/monitored acceptable.

[Detection of Aging Effects] The applicant described this activity as a one-time inspection that will detect the presence and extent of any loss of material due to selective leaching. The staff found, based on the material in the application, that the inspection will be capable of detecting aging effects, and will permit the applicant to take corrective actions prior to loss of component intended function.

[Monitoring and Trending] The applicant stated that, of the cast iron components in the systems within the scope of the program, the Selective Leaching Inspection will perform a Brinnell hardness test or an equivalent test on one cast iron pump casing in the exterior fire protection system at each site. The Brinnell hardness test or an equivalent test is most easily performed on a pump casing and will be indicative of all cast iron components in the systems listed above.

According to the application, the exterior fire protection system contains a raw water environment that is susceptible to selective leaching and will be bounding for the other environments in the other systems. If no parameters are known that would distinguish among the pump casings, the applicant stated that one of the three cast iron pump casings in the exterior fire protection system will be examined based on accessibility and operational concerns. The results of this inspection will be applied by the applicant to the other cast iron components exposed to raw water environments in the systems listed above. The Selective Leaching Inspection program will also perform a Brinnell hardness test, or an equivalent test, on a sample of brass valves at each site in the interior fire protection system. Valves selected for inspection will be in locations where they are continuously exposed to stagnant or low-flow raw water environments. If no parameters are known that would distinguish the susceptible locations at each site, a select set of susceptible locations will be examined by the applicant based on accessibility, operational, and radiological concerns. The results of the inspection will be applied to brass components exposed to raw water environments in the systems listed above.

Based on the information in the application, the staff found that the monitoring and trending activities will provide a basis on which the applicant may make a determination of acceptability of the components in the systems subject to the aging management program.

[Acceptance Criteria] The acceptance criteria for the Selective Leaching Inspection is no unacceptable loss of material due to selective leaching that could result in a loss of the component intended functions(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.28-3, that the applicant describe the criteria to be used to define "unacceptable loss of material" and to describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

In its response dated March 15, 2002, the applicant stated that if evidence of loss of material is observed during the initial inspection, a problem report will be developed in accordance with "Problem Investigation Process of Nuclear System Directive 208." The Problem Investigation Process is a formalized process used by the applicant for documenting engineering evaluations of plant problems. The applicant provided examples of criteria or analysis methods that may be used, including ASME Code requirements, to assess the severity of degradation and the need for corrective action. The applicant stated that any criteria or analysis methods involved in determining the severity of the degradation and the need for corrective action will be developed at the time of the evaluation and will be a part of the problem report. The staff finds that, because degradation is detectable by the methods to be applied, ASME Code requirements or some other analysis method will be applied as acceptance criteria, and the existing problem investigation process conforms to 10 CFR Part 50, Appendix B requirements (as documented in Section 3.0.4 of this SER), the acceptance criterion is acceptable.

[Operating Experience] This program is described by the applicant as a new, one-time inspection for which there is no operating experience. Since there is no operating experience with this new AMP, and since uncertainty exists as to whether long-term exposure to raw water environments could cause loss of material due to selective leaching in brass and cast iron components such that they may lose their pressure boundary function in the period of extended operation, the staff finds this one-time inspection an acceptable means to characterize any loss of material due to selective leaching of system components exposed to raw water environments.

With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by June 12, 2021, for McGuire and by December 6, 2024, for Catawba.
The staff finds this inspection schedule acceptable. If present, selective leaching is a slow-acting corrosion mechanism; thus, the staff expects minimal corrosion, if any, and finds the use of a one-time inspection capable of identifying degradation and allowing the applicant to take appropriate corrective action prior to loss of component function.

3.0.3.14.3 FSAR Supplement

Section 18.2.23 of LRA Appendix A-1 contains the McGuire FSAR supplement describing the Selective Leaching Inspection program. Section 18.2.22 of the LRA Appendix A-2 contains the Catawba FSAR supplement for the Selective Leaching Inspection program. The contents of these sections are consistent with the description provided in Appendix B, Section B.3.28 of the LRA, therefore the staff does not see the need for changes.

3.0.3.14.4 Conclusions

The staff has reviewed the information provided in Section B.3.28 of LRA Appendix B. On the basis of this review, as set forth above, including the applicant's responses to the staff requests for additional information, the staff found that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Selective Leaching Inspection program structures and components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.15 Service Water Piping Corrosion Program

The applicant describes the Service Water Piping Corrosion Program at McGuire and Catawba in Section B.3.29 of LRA Appendix B. The purpose of the program is to manage aging effects of loss of material due to corrosion or erosion that could lead to loss of the pressure boundary function of specific raw water system components. The staff reviewed Section B.3.29 of LRA Appendix B to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.15.1 Technical Information in the Application

The applicant has described the Service Water Piping Corrosion Program in Section B.3.29 of LRA Appendix B. The purpose of this program is to manage the more uniform loss of material, such as that due to general corrosion, as well as particulate erosion, in areas of higher flow velocity, for the following systems:

- containment ventilation cooling water (McGuire only)
- exterior fire protection
- interior fire protection
- nuclear service water

Additionally, the program is credited with managing loss of material for heat exchanger sub-components in the following systems:

- containment spray
- diesel generator cooling water
- control area chilled water
- diesel generator engine starting air (Catawba only)

Components in the McGuire and Catawba raw water systems subject to these aging effects are made from carbon and galvanized steel, cast and ductile iron, and copper alloys.

3.0.3.15.2 Staff Evaluation

The staff's evaluation of the Service Water Piping Corrosion Program focused on the program elements rather than details of specific plant procedures. The staff evaluated how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] For license renewal, the applicant credits the Service Water Piping Corrosion Program with managing loss of material for components in the following systems:

- containment ventilation cooling water (McGuire only)
- exterior fire protection
- interior fire protection
- nuclear service water

Additionally, the program is credited with managing loss of material for heat exchanger sub-components in the following systems:

- containment spray
- diesel generator cooling water
- control area chilled water
- diesel generator engine starting air (Catawba only)

Because this scope is comprehensive, in that it includes those components and systems subject to general corrosion, the staff finds the scope acceptable.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of the program to prevent aging effects or to mitigate aging degradation. The staff considers the inspections as a means to detect, not prevent degradation and, therefore, did not identify a need for preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the Service Water Piping Corrosion Program inspections are focused on carbon steel piping components exposed to raw water. Among the installed component materials, carbon steel is the more susceptible to general loss of material and serves as a leading indicator of the general material condition of the system components. The applicant relies on inspection of carbon steel piping to provide symptomatic evidence of loss of material of other components and other materials exposed to raw water. The specific parameter monitored by the applicant is pipe wall thickness as an indicator of loss of material. Because monitoring wall thickness will provide a valid indicator of loss of material and provide an opportunity to take corrective action before loss of component function, and because this is a standard industry practice, the staff finds this acceptable.

[Detection of Aging Effects] The applicant stated that the Service Water Piping Corrosion Program will detect the more uniform loss of material, such as that due to general corrosion, as well as particulate erosion, that may occur in areas of higher flow velocity. The program will also detect loss of material due to localized corrosion such as crevice, pitting, and microbiologically influenced corrosion (MIC). Because the program uses volumetric techniques current in the industry and capable of detecting aging effects in the inspected components, the staff finds this acceptable.

[Monitoring and Trending] The applicant stated that the Service Water Piping Corrosion Program manages all of the system components within license renewal scope that are susceptible to the various corrosion mechanisms, and is not focused on individual components within each specific system. As described in the LRA, the intent of the program is to inspect a number of locations with conditions that are characteristic of the conditions found throughout the raw water systems within the program scope. The applicant then applies the results of these inspections to similar locations throughout all the raw water systems within the scope of license renewal. This characteristic-based approach recognizes the commonality among the component materials of construction and the environment to which they are exposed.

Monitoring under the program focuses on carbon steel pipe. Industry experience has shown that loss of material for components constructed of cast and ductile iron, galvanized steel, and copper alloys will occur at a rate somewhat less than the carbon steel pipe. Therefore, the results of the carbon steel pipe inspections will provide a leading indicator of the condition of these materials.

For the carbon and galvanized steel, cast and ductile iron, and copper alloy component materials that can experience loss of material from both uniform and localized mechanisms, the applicant stated that it is the gross material loss due to uniform mechanisms that is of primary concern under the Service Water Piping Corrosion Program. Gross wall loss can lead to structural instability concerns and could directly impact component intended function. Monitoring for uniform loss of material is accomplished with the use of ultrasonic test techniques, supplemented by visual inspections if access to the interior surfaces is allowed, such as during plant modifications.

When pipe wall thickness is determined by volumetric wall thickness measurements using ultrasonic testing, several measurements are taken around the circumference of the piping. These measurements are then assessed in relation to the specific acceptance criteria for that location. Because the phenomena are slow-acting, inspection frequency varies for each location. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events, and plant operating experience. Component results are catalogued by the applicant, and future inspection or component replacement schedules are determined as a part of the program.

The applicant stated that localized corrosion due to pitting and MIC will reveal itself through pinhole leaks in the piping components. The geometry of the pinholes means that they are not a structural integrity concern. Further, these pinhole leaks cannot individually lead to loss of the component intended function, since sufficient flow at prescribed pressures can still be provided by the system. These localized concerns will lead to structural integrity concerns only when a significant number of pinholes are present. A trend of indications of through-wall leaks due to pitting corrosion or MIC will provide the applicant with evidence when localized corrosion may become a structural integrity concern, and will trigger corrective actions. However, the staff believed that localized corrosion can result in the loss of pressure boundary intended function under a design basis event before the corrosion reveals itself as pinhole leaks. Therefore, the applicant was requested to justify how its program will manage the effects of localized corrosion from pitting and MIC to ensure that the intended pressure boundary function can be maintained under all design basis events consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(3). This issue was characterized as SER open item 3.0.3.15.2-1.

In its response dated October 28, 2002, the applicant provided a more detailed description of its program for inspecting piping in the service water system. The program utilizes ultrasonic technology to look for loss of material. The periodic ultrasonic testing (UT) identifies any potential areas of severe degradation by corrosion that could exceed the ability of piping to maintain its structural integrity. Although the primary issue addressed by the program is gross wall loss which could lead to structural instability, the program also includes the areas containing localized corrosion by pitting and other localized corrosion mechanisms. This was required because localized corrosion may become a structural concern when a significant number of pinholes are present in one area. When an occurrence of localized corrosion is identified either by UT or a pinhole leak, an evaluation is performed to justify structural integrity of the inspected component under all design conditions. This ensures that the service water corrosion program addresses localized corrosion affecting structural integrity of the affected components before it is revealed as a pinhole leak. In order to achieve this, the program was designed to perform appropriate inspections, evaluations, and trending and to take appropriate corrective actions. The staff finds that, by following this process, the applicant will be able to detect the effects of localized corrosion from pitting and MIC before structural integrity of the piping is jeopardized. Therefore, open item 3.0.3.15.2-1 is closed.

While the emphasis of the Service Water Piping Corrosion Program remains on gross material loss, the loss of material due to localized corrosion of component materials exposed to raw water will be managed by the monitoring and trending of relevant plant operating experience of non-structural, through-wall leaks identified during various plant activities. Methods used by the applicant to identify incidents of through-wall leaks are system walkdowns, operator rounds, system testing, and maintenance activities. This relevant operating experience will form the basis for any future programmatic actions with respect to pitting corrosion and MIC concerns.

By letter dated January 28, 2002, the staff requested, in RAI B.3.29-1, additional information regarding the methods the applicant planned to use to select the UT procedures and the number of locations to be inspected. In its response dated March 15, 2002, the applicant stated that the methods used to select the UT procedures, including grid size and the number of locations to be inspected, were developed as a department initiative among the applicant's three nuclear plant sites. Original efforts to define inspection procedure details were made as a part of the applicant's response to NRC Generic Letter 89-13. Additionally, the applicant has been involved in industry efforts sponsored through EPRI to address the service water corrosion issue.

The staff finds this response to be acceptable and concludes, based on information in the application and the response to the question, that the monitoring and trending of the inspection results is capable of identifying problems before they could result in loss of pressure boundary integrity.

[Acceptance Criteria] The Service Water Piping Corrosion Program manages loss of material for nuclear safety-related and non-nuclear safety-related components. For nuclear safety-related components designed to ASME Section III, Class 3 rules, the acceptance criteria are defined as meeting ASME Code requirements in order to assure structural integrity. Several factors are used by the applicant to determine structural integrity at an inspection location. These factors include consideration of actual as-found wall thickness, calculated rate of material loss, use of the piping stress analyses to determine a minimum required thickness, and projected time to reach the minimum wall thickness. Projected time to reach the minimum wall thickness will establish the re-inspection interval or component replacement schedule.

For the non-nuclear safety-related components that have no seismic design requirements, the applicant's acceptance criterion is the minimum wall thickness calculated on a location-specific basis. These minimum values have been determined by the applicant based on design pressure or structural loading using the piping design code of record and applying additional conservatism.

The staff concludes that, because the inspection methods are capable of detecting the effects of corrosion, and the inspections are performed using common industry methods, the acceptance criteria are appropriate for the various classes of components inspected.

[Operating Experience] The Service Water Piping Corrosion Program was formalized by the applicant at each site in the early 1990's as a part of the efforts to address NRC Generic Letter 89-13. Test results have indicated mostly pitting corrosion problems. Typical corrosion rates have ranged from 3 to 5 mils per year average wall loss, but vary depending on line size and flow regime. Test locations continue to be monitored and evaluated by the applicant for continued service. The applicant stated that piping replacements have not been required to date, based on corrosion rate projections. The applicant has refined the predictive capabilities of the program over time, and the program now includes monitoring and trending to determine calculated rate of material loss to schedule the next inspection. Operating experience has demonstrated that using measured corrosion rates provides adequate information on the extent of loss of material to predict when replacement of components might be necessary. Stress analysis of components has allowed the applicant to refine acceptance criteria and extend the life of some pipe sections. Overall the applicant reports that the program continues to successfully manage loss of material in the raw water systems of McGuire and Catawba.

By letter dated January 28, 2002, the staff requested, in RAI B.3.29-2, additional information and examples regarding the corrosion rates for specific systems, and examples of how measurements have been used to determine frequencies of reinspection and to expand the number of locations for wall thickness measurements. In its response dated March 15, 2002, the applicant stated that a review of over 100 inspection locations in the nuclear service water system revealed that the worst locations experience corrosion rates of approximately 3 to 5 mils per 18-month operating cycle, based on the low-band averages (lowest average wall thickness in a circumferential band) of the inspection locations.

The applicant stated that other locations, such as stagnant locations, exhibited much lower corrosion rates. The applicant stated that the frequency of reinspection is determined using the calculated corrosion rate. Corrosion rate, and thus reinspection frequency, is determined by comparing the low-band average of the inspection location against the nominal wall thickness, and is averaged against the number of operating cycles. This value is then compared against the minimum allowed wall thickness to determine the remaining life (approximate replacement cycle). The applicant further stated that sample expansion has been required rarely because of the number of inspection locations already in the program. The program provides data points representing all piping, including piping upstream and downstream of major pieces of equipment; every pipe size; different flow regimes; and each stress analysis math model. In its response, the applicant stated that sample expansion is performed in some instances where one inspection location is used as a representative location of both trains or units to include inspection of the opposite train or unit.

Because the applicant adequately addressed the specific information requested, the staff finds the response to be acceptable. Additionally, the staff finds that the applicant's experience is consistent with that of others in the industry and provides a sound basis for successful management of material loss in the raw water systems. Therefore, the staff concludes that the operating experience indicates that the program has been effective, and that there is reasonable assurance that it will continue to be effective at managing the aging effects through the period of extended operation.

3.0.3.15.3 FSAR Supplement

Section 18.2.24 of LRA Appendix A-1, and Section 18.2.23 of LRA Appendix A-2, provide proposed new UFSAR sections describing the Service Water Piping Corrosion Program for McGuire and Catawba, respectively. In its response to SER open item 3.0.3.15.2-1, the applicant provided a revised FSAR supplement summary description of the Service Water Piping Corrosion Program to reflect the additional detail provided to resolve the open item. The staff reviewed the material provided in the FSAR supplement, and in correspondence from the applicant, and determined that the information is consistent with the material in the LRA and in the response to SER open item 3.0.3.15.2-1 and, therefore, is acceptable.

3.0.3.15.4 Conclusion

The staff reviewed the information provided in Section B.3.29 of LRA Appendix B, the summary description in the FSAR supplements in Appendix A of the LRA, the applicant's March 15, 2002, responses to the staff's RAIs, and the applicant's October 28, 2002, response to SER open item 3.0.3.15.2-1. On the basis of this review and the above evaluation, and with the resolution of SER open item 3.0.3.15.2-1, the staff finds that there is reasonable assurance that the Service Water Piping Corrosion Program will adequately manage the aging effects such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.16 Sump Pump Systems Inspection

The applicant described its Sump Pump Systems Inspection program in Section B.3.32 of LRA Appendix B. The applicant credits this program with managing the potential aging of sump components that are within the scope of license renewal. The activity is a one-time volumetric inspection of the components of the limiting sump (i.e., the diesel generator room sump) to detect loss of material. The staff reviewed Section B.3.32 of LRA Appendix B to determine whether the applicant has demonstrated that Sump Pump Systems Inspection activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.16.1 Technical Information in the Application

Section B.3.32 of LRA Appendix B states that the purpose of the Sump Pump Systems Inspection program is to characterize any loss of material of the internal and external surfaces of a limited set of mechanical components exposed to sump environments. Sump environments may contain leakage from a variety of systems, but are considered to be raw water environments with alternate wetting and drying as sump levels change. Uncertainty exists as to whether long-term exposure to these sump environments could cause loss of material of system components such that they may lose their pressure boundary function in the period of extended operation. This activity will inspect components constructed of various materials to detect the presence and extent of any loss of material from exposure to raw water, including alternate wetting and drying. This is a one-time inspection for the following systems:

- diesel generator room sump pump system
- conventional wastewater treatment system (McGuire only)
- groundwater drainage system
- turbine building sump pump system (Catawba only)

3.0.3.16.2 Staff Evaluation

The staff's evaluation of the Sump Pump Systems Inspection program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive and mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the plant procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The scope of the Sump Pump Systems Inspection is a limited set of mechanical components constructed of carbon steel, cast iron, and stainless steel exposed to sump environments in the following McGuire and Catawba systems:

- diesel generator room sump pump system
- conventional wastewater treatment system (McGuire only)
- groundwater drainage system
- turbine building sump pump system (Catawba only)

The staff finds the scope of the program adequate because it will detect and manage the aging effects in the components subject to sump pump environments.

[Preventive or Mitigative Actions] No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation, and the staff did not identify a need for any.

[Parameters Monitored or Inspected] The parameter inspected by the Sump Pump Systems Inspection is wall thickness as a measure of loss of material. The staff finds that wall thickness measurement will permit detection of aging effects in sump pump components, and is acceptable.

[Detection of Aging Effects] The Sump Pump Systems Inspection is a one-time inspection that will detect the presence and extent of loss of material due to crevice, general, pitting, and microbiologically influenced corrosion. Volumetric inspections will be used to determine wall thickness measurements. The staff finds that the determination of wall thickness by this technique will provide satisfactory means for detecting aging effects in the components exposed to sump pump environments.

[Monitoring and Trending] Section B.3.32 of LRA Appendix B describes the sump pump systems inspection activities as follows:

> The "Sump Pump Systems Inspection" will inspect sump components at each site located within the Diesel Generator Room Sump Pump System using a volumetric examination technique. The Diesel Generator Room Sump Pump System was selected for inspection because the system contains a representation of all of the materials present within the other sump environments. The sump environment in the Diesel Generator Room Sump Pump System is a potential combination of leakage of raw water, fuel oil, and treated water. Inspection of the Diesel Generator Room Sump Pump System will provide a representative review of the condition of mechanical components materials subject to a sump environment.
>
> Inspection locations will be at piping low points, pump casings, and valve bodies where materials are continuously wetted by the raw water environment or subject to alternate wetting and drying. The results of this inspection will be applied to the mechanical components in the Conventional Waste Water Treatment (MNS only), Groundwater Drainage, and Turbine Building Sump Pump Systems (CNS only).

Section B.3.32 of LRA Appendix B states that no actions will be taken as part of this activity to trend inspection or test results. The staff did not identify the need for any. Section B.3.32 of LRA Appendix B also stated that, should industry data or other evaluations indicate that the above inspections can be modified or eliminated, the applicant will provide plant-specific justification to demonstrate the basis for the modification or elimination. The staff finds this acceptable.

[Acceptance Criteria] Section B.3.32 of LRA Appendix B states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B.3.32-1, the applicant to describe the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant indicated that acceptance criteria will be based on ASME Code requirements, results from additional inspections, and operating experience, the staff finds the applicant's response reasonable and acceptable.

3.0.3.16.3 FSAR Supplement

The staff has reviewed LRA Appendix A-1 (McGuire), Section 18.2.25, and LRA Appendix A-2 (Catawba), Section 18.2.24, and finds that the FSAR supplements contain the appropriate elements of the program.

3.0.3.16.4 Conclusion

The staff reviewed Section B.3.32 of LRA Appendix B, the FSAR supplement provided in Appendix A of the LRA, and the applicant's March 15, 2002, response to the staff's request for additional information. On the basis of this review and the above evaluation, the staff finds that the implementation of the Sump Pump Systems Inspection program provides reasonable assurance that the aging effects of loss of material will be managed such that components within the scope of license renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.17 Treated Water Systems Stainless Steel Inspection

Section B.3.34 of LRA Appendix B describes the applicant's Treated Water Systems Stainless Steel Inspection program for monitoring the aging of stainless steel components of unmonitored treated water systems. This one-time inspection is intended to detect the presence and extent of any loss of material or cracking of stainless steel components exposed to unmonitored treated water within these systems. The staff reviewed Section B.3.34 of LRA Appendix B to determine whether the applicant has demonstrated that the effects of aging will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.17.1 Technical Information in the Application

The Treated Water Systems Stainless Steel Inspection program is described in Section B.3.34 of LRA Appendix B. The purpose of the program is to characterize the loss of material or cracking of stainless steel components resulting from exposure to unmonitored treated water environments. An unmonitored treated water environment is one that may contain conditions that can concentrate existing levels of contaminants, or that may simply start with a higher level of contaminants than those systems routinely monitored by the Chemistry Control Program. The Treated Water Systems Stainless Steel Inspection includes a one-time inspection of stainless steel components, welds, and heat-affected zones, as applicable, in the following systems:

- containment valve injection water (Catawba only)
- drinking water (Catawba only)
- nuclear solid waste disposal (McGuire only)
- solid radwaste (Catawba only)

For the McGuire nuclear solid waste disposal system, volumetric examinations will be conducted in stagnant and low-flow lines around the spent resin storage tanks, and a visual examination will be conducted of the interior of a valve to determine the presence of pitting corrosion. For Catawba, the volumetric examinations will be performed on the drinking water system because this system receives water from the local municipality. This water has contaminant levels in excess of limits below which a concern would not exist for cracking and loss of material in stainless steel, and is considered to bound the environments of the other Catawba systems within the scope of this inspection. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion.

3.0.3.17.2 Staff Evaluation

The staff's evaluation of the Treated Water Systems Stainless Steel Inspection program focused on the program elements rather than details of specific plant procedures. The staff evaluated how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective actions process, while the administrative controls are implemented through the site procedures and work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] The applicant identified the scope as stainless steel components exposed to unmonitored treated water environments in the following McGuire and Catawba systems:

- containment valve injection water (Catawba)
- drinking water (Catawba)
- nuclear solid waste disposal (McGuire)
- solid radwaste (Catawba)

Because the scope is comprehensive and includes systems and components representative of stainless steel components exposed to unmonitored treated water, the staff finds the scope to be acceptable.

[Preventive or Mitigative Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging effects. Since this is a condition monitoring program, the staff did not identify the need for preventive or mitigative actions.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the Treated Water Systems Stainless Steel Inspection program is pipe wall thickness as an indicator of loss of material and evidence of cracking.

The staff notes that three factors have been identified that promote stress corrosion cracking of stainless steels: (1) metallurgical (sensitization), (2) stress level, and (3) environmental. The basis in the LRA for the proposed Catawba inspections only focused on the environment. By letter dated January 28, 2002, the staff requested, in RAI B.3.34-1, additional information regarding how the metallurgical and stress level factors were considered in the system susceptibility comparisons. In its response dated March 15, 2002, the applicant indicated that all three factors were considered and provided the following explanation of how it had evaluated environmental conditions:

> Environmental effects are the third parameter playing a role in promoting stress corrosion cracking. Dissolved oxygen and halogens are contributors to stress corrosion cracking of stainless steel. For the three Catawba systems within the scope of this one-time inspection, the Drinking Water System has the highest contaminant levels. This difference is the only clear cut distinction among the systems. The Containment Valve Injection Water System is filled with demineralized water. The Solid Radwaste System receives borated water from plant systems. Demineralized water and borated water used at Catawba contain lower levels of the contaminants known to be a concern for stress corrosion cracking than the Drinking Water System.
>
> While Duke does not believe that loss of material and cracking of stainless steel components within these systems is occurring, the aging effects could not absolutely be ruled out. Duke decided that an inspection was warranted and will focus on the Catawba Drinking Water System as the leading indicator for the Treated Water Stainless Steel Inspection.

Since the applicant does not believe that loss of material and cracking of stainless steel components within these systems is occurring, but could not rule out the potential for these aging effects, the applicant plans to perform this one-time inspection to characterize any loss of material or stress corrosion cracking of the stainless steel components in the treated water systems. Therefore, the staff finds the applicant's response to be acceptable.

Based on the information provided in the LRA and the applicant's response to the RAI, the staff finds that the parameters monitored are capable of detecting loss of material prior to loss of component function.

[Detection of Aging Effects] Section B.3.34 of LRA Appendix B states that the Treated Water Systems Stainless Steel Inspection is a one-time inspection that will detect the presence and extent of loss of material or cracking of stainless steel components exposed to unmonitored treated water environments. Because the volumetric and visual examinations are capable of detecting loss of material or cracking of stainless steel components exposed to unmonitored treated water environments, the staff finds this acceptable.

[Monitoring and Trending] The applicant stated that it will perform a volumetric examination of various susceptible piping locations in the nuclear solid waste disposal system at McGuire and in the drinking water system at Catawba. These examinations will include stainless steel welds and heat-affected zones since these are the likely locations for stress corrosion cracking to occur. The use of volumetric examinations, which evaluate the full volume of the piping, will ensure that unacceptable pipe flaws will be identified. In addition to the volumetric examination, the applicant will visually examine the interior of a valve to determine the presence of pitting corrosion. The program calls for a one-time inspection.

The staff finds that the volumetric examination techniques proposed are consistent with current industry practice. Furthermore, since this is a one-time inspection, trending inspection results are not necessary. Based on the staff's review of the application and the applicant's March 15, 2002, response to RAI B.3.34-1 (discussed under the Parameters Monitored or Trended element), the staff finds the monitoring activities to be appropriate to identify loss of material or defects.

[Acceptance Criteria] Section B.3.34 of LRA Appendix B states that the acceptance criteria for the inspection is no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation. By letter dated January 28, 2002, the staff requested, in RAI B 3.34-2, additional information regarding the criteria for assessing the severity of observed degradations and the need for corrective actions. In its response dated March 15, 2002, the applicant stated that the criteria would be developed at the time of the inspection. Criteria such as the ASME Code, results from additional inspections, and operating experience may be used to assess the severity of the degradation and the need for corrective action. Since the applicant referenced ASME Code requirements, results from additional inspections, and operating experience as the bases for its acceptance criteria, the staff finds the applicant's response reasonable and acceptable.

Because the methods to be used by the applicant are capable of detecting defects or loss of material, and the identification of these parameters will enable the applicant to take corrective action prior to loss of component function, the staff finds the acceptance criteria to be acceptable.

[Operating Experience] The applicant stated that the Treated Water Systems Stainless Steel Inspection is a one-time inspection, for which there is no operating experience. The staff agrees that there is no operating experience with this inspection at Catawba and McGuire. The staff finds this reasonable and acceptable.

3.0.3.17.3 FSAR Supplement

Section 18.2.26 of LRA Appendix A-1, and Section 18.2.25 of LRA Appendix A-2, provide FSAR supplements for McGuire and Catawba, respectively. These sections describe the Treated Water Systems Stainless Steel Inspection program and are consistent with the program description in Section B.3.34 of LRA Appendix B. Therefore, the staff finds them acceptable.

3.0.3.17.4 Conclusions

The staff reviewed the information provided in Section B.3.34 of LRA Appendix B, the summary description in the FSAR supplement in Appendix A of the LRA, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that there is reasonable assurance that the aging effect of loss of material and cracking of the stainless steel piping and components within the scope of the program will be adequately managed, such that the intended function will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.18 Underwater Inspection of Nuclear Service Water Structures

The applicant describes its Underwater Inspection of Nuclear Service Water Structures program in Section B.3.35 of LRA Appendix B. The applicant credits this inspection activity with managing the potential aging of nuclear service water (NSW) structures and the low pressure service water intake structure at Catawba and components that are within the scope of license renewal. The inspection activity monitors and assesses the condition of NSW structures for loss of material of steel components and loss of material and cracking of concrete components. The staff reviewed Section B.3.35 of LRA Appendix B to determine whether the applicant has demonstrated that the Underwater Inspection of Nuclear Service Water Structures program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.18.1 Technical Information in the Application

Section B.3.35 of LRA Appendix B states that the purpose of the Underwater Inspection of Nuclear Service Water Structures program is to provide reasonable assurance that the effects of aging will be managed so that the intended function(s) of equipment and components within the scope of 10 CFR Part 54 will be maintained consistent with the CLB for the period of extended operation. This program is credited with managing loss of material of steel and loss of material and cracking for concrete for the period of extended operation for the following structures:

McGuire —
- standby nuclear service water discharge structures
- standby nuclear service water intake structure

Catawba —
- low pressure service water intake structure
- nuclear service water intake structure
- nuclear service water pump structure
- standby nuclear service water discharge structures
- standby nuclear service water intake structure
- standby nuclear service water pond outlet

The Underwater Inspection of Nuclear Service Water Structures program detects aging effects through visual examination. The inspection is performed every 5 years at McGuire. At Catawba, the inspection is performed every Unit 1 refueling outage for the NSW structure and standby nuclear service water intake structures, and every 5 years for other structures. The acceptance criteria are no unacceptable visual indication of (1) loss of material for steel components, and (2) loss of material and cracking for concrete components, as determined by the "accountable engineer." Structures and components that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service, and are repaired as required. Structures and components which are deemed unacceptable are documented under the corrective action program. Specific corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program. The applicant stated that a review of previous inspections indicates that the standby nuclear service water intake and discharge structures at McGuire are in good working condition. At Catawba, previous inspections of NSW structures have revealed only minor degradation. No deterioration that could cause loss of intended function has been identified from the previous inspections.

3.0.3.18.2 Staff Evaluation

The staff's evaluation of the Underwater Inspection of Nuclear Service Water Structures program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive and mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action program, while the administrative controls are implemented through plant procedures and the site work processes. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

[Scope of Program] Section B.3.35 of LRA Appendix B states that the following structures and components credit the Underwater Inspection of Nuclear Service Water Structures program:

McGuire —
- standby nuclear service water discharge structures
- standby nuclear service water intake structure

Catawba —
- low pressure service water intake structure
- nuclear service water intake structure
- nuclear service water pump structure
- standby nuclear service water discharge structures
- standby nuclear service water intake structure
- standby nuclear service water pond outlet

The scope covers the in-scope structures that are exposed to pond water at McGuire and pond or lake water at Catawba, and is therefore acceptable to the staff.

[Preventive Actions] There are no preventive actions taken as part of this program, and the staff did not identify the need for any preventive actions.

[Parameters Monitored or Inspected] Section B.3.35 of LRA Appendix B identifies loss of material for steel components, and loss of material and cracking for concrete components, as the parameters that can be detected by visual inspection. Because visual inspection can be used to identify the degraded conditions noted by the applicant, such inspections of the nuclear service water structures are acceptable to the staff.

[Detection of Aging Effects] Section B.3.35 of LRA Appendix B states that visual inspection will detect loss of material for steel components, and loss of material and cracking for concrete components, prior to the loss of structure or component intended functions. The use of visual inspection is considered by the staff to be a reasonable means of detecting these aging effects before the loss of intended function, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.35 of LRA Appendix B states that the inspections are performed every 5 years at McGuire, every Unit 1 refueling outage for Catawba NSW and standby nuclear service water intake structures, and every 5 years for the other Catawba structures. No actions are taken as part of the program to trend the inspection results, but the inspection reports are retained in sufficient detail to permit confirmation of the inspection programs. Since structures and components that do not meet the acceptance criteria are evaluated for continued service and repaired as required, and since corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program, the staff finds this acceptable.

[Acceptance Criteria] Section B.3.35 of LRA Appendix B states that the acceptance criteria is no unacceptable visual indication of (1) loss of material for steel components, and (2) loss of material and cracking for concrete components, as determined by the "accountable engineer."

Since the assessment of the severity of the observed degradation, and determination of whether corrective action is necessary, is based on the judgment of the accountable engineer, by letter dated January 28, 2002, the staff requested, in RAI B.3.35-1, additional information regarding the qualifications of the accountable engineer. In its response dated March 11, 2002, the applicant stated that the accountable engineer's qualifications are in accordance with RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants." Because the acceptance criteria are consistent with the degradation of concern, which is detectable by visual inspections, and because the inspections and evaluations will be conducted by knowledgeable and experienced individuals with qualifications in accordance with RG 1.127, the staff finds this acceptable.

Since the LRA is not clear regarding the extent to which a loss of material or cracking is acceptable, by letter dated January 28, 2002, the staff requested, in RAI B.3.35-2, a description of the criteria for (1) assessing the severity of the observed degradations, and (2) determining whether corrective action is necessary. In its response dated March 11, 2002, the applicant stated that the examination and assessment of the structure's condition follows the guidance of RG 1.127, ACI 349.3, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and ACI 201, "Guide for Making a Condition Survey of Concrete in Service." In addition, the applicant stated that the visual inspections for these types of degradation have been addressed in NRC Inspection Procedure 62002, "Inspection of Structure, Passive Components, and Civil Engineering Features at Nuclear Power Plants," and NEI 96-03, "Industry Guideline for Monitoring Structures." Since the inspections use the appropriate guidance, as listed above, the staff finds this acceptable.

[Operating Experience] Section B.3.35 of LRA Appendix B describes the plant-specific operating experience related to the underwater inspections of the nuclear service water structures. At McGuire, a review of previous inspection reports indicates the standby nuclear service water intake and discharge structures are in good working condition. McGuire's old, galvanized steel trash racks and fasteners were noted to be degraded when they were replaced in 1992 with stainless steel trash racks. At Catawba, previous inspections have revealed only minor degradation; no deterioration that could cause a loss of intended function has been identified. The staff finds that the McGuire and Catawba operating experience indicates that the underwater inspection activities of the NSW structures are effective in managing the aging effects of the structures.

3.0.3.18.3 FSAR Supplement

The staff reviewed Section 18.2.27 and Section 18.2.26 of the FSAR supplements for McGuire and Catawba, respectively, in Appendix A of the LRA. The staff found that some important industry standards and the NRC guidelines used for the AMP were not incorporated into the FSAR supplements. This issue was characterized as SER open item 3.0.3.18.3-1. In its response dated October 2, 2002, the applicant provided a revised FSAR supplement that included the appropriate industry standards. The staff finds that the revised FSAR supplement provides a summary description of the program at a level of detail commensurate with that which is provided in the staff's review guidance (Appendix A of NUREG 1800) and is, therefore, acceptable. Therefore, open item 3.0.3.18.3-1 is resolved.

3.0.3.18.4 Conclusions

The staff has reviewed the information provided in Section B.3.35 of LRA Appendix B and the summary description of the Underwater Inspection of Nuclear Service Water Structures in Appendix A of the LRA. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAIs. On the basis of this review and the above evaluation, the staff finds that the Underwater Inspection of Nuclear Service Water Structures program will adequately manage the aging effects such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.19 Ventilation Area Pressure Boundary Sealants Inspection

In response to open item 2.3-3, by letter dated October 28, 2002, the applicant submitted the Ventilation Area Pressure Boundary Sealants Inspection program. By letter dated November 14, 2002, the applicant submitted a corrected version of this program. In its letter, the applicant indicated that previously proposed programs that credited existing technical specification surveillances provided assurance that the design basis function of the structural sealants was being met. However, the staff was concerned that these surveillances, which focused on differential pressures between the pressure boundary envelopes and adjacent areas, tested the system fan's capability to compensate for sealant degradation and leakage. Therefore, the staff requested the applicant to propose an alternative program that would monitor or manage aging of the sealant specifically.

The Ventilation Area Pressure Boundary Sealants Inspection program is credited with monitoring the potential aging effects of cracking and shrinkage of structural sealant in ventilation system applications for which pressure boundary is an intended function. The staff reviewed the program description to determine whether the applicant has demonstrated that the Ventilation Area Pressure Boundary Sealants Inspection program will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.3.19.1 Technical Information in the Response to SER open item 2.3-3

The applicant provided a description of this program in a letter to the NRC dated November 14, 2002. The applicant stated that the purpose of this one-time inspection program is to characterize any cracking or shrinkage of structural sealants due to exposure to ambient conditions. The visual inspections will identify cracking and shrinkage of the structural sealants that would result in loss of intended function.

3.0.3.19.2 Staff Evaluation

The staff's evaluation of the program focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive and mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The LRA indicates that the corrective actions and confirmation process are implemented through the site corrective action process, while the administrative controls are implemented through the site procedures. The staff's evaluation of the corrective actions, confirmation process, and administrative controls is provided in Section 3.0.4 of this SER. The remaining seven elements are discussed below:

[Scope of Program] The scope of the Ventilation Area Pressure Boundary Sealants Inspection is the pressure boundary structural sealants installed in the ventilation pressure boundary of the control room, emergency core cooling system (ECCS) pump room, reactor building annulus, and fuel handling building. Pressure boundary structural sealants include, but are not limited to, sealants in the interface between a structural wall, floor, or ceiling and a non-structural component such as duct, piping, electrical cables, doors, and non-structural walls. The staff finds the program scope acceptable since the program manages aging for the structural sealants installed in the ventilation pressure boundary of the control room, ECCS pump room, annulus, and fuel handling areas.

[Preventive and Mitigative actions] No actions are taken as a part of this surveillance one-time inspection to prevent aging effects or to mitigate aging degradation. The staff concurs that no preventive actions are required for this condition monitoring program.

[Parameters Monitored or Inspected] Ventilation Area Pressure Boundary Sealants Inspection is a visual inspection for cracking or shrinkage of the structural sealants. The staff finds the parameters inspected are acceptable since a visual inspection of the structural sealants will detect the presence and extent of the aging effect which is cracking or shrinkage.

[Detection of Aging Effects] In accordance with the information provided in Monitoring and Trending, the Ventilation Area Pressure Boundary Sealants Inspection will detect cracking or shrinkage of the ventilation area pressure boundary structural sealants. There is no operating experience for cracking or shrinkage of structural sealants. Therefore, the staff finds the one-time visual inspection performed following the issuance of the renewed license, and prior to the end of the current operating term, an acceptable method to detect cracking or shrinkage of structural sealants. The one-time visual inspection will confirm that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function. If inspection results are not acceptable, specific corrective actions will be implemented by the applicant, in accordance with the corrective action program, to ensure the component intended function will be maintained during the period of extended operation.

[Monitoring and Trending] The Ventilation Area Pressure Boundary Sealants Inspection will visually inspect a representative sample of structural sealants at each station. Locations of inspections will be based on severity of the local ambient conditions taking into consideration temperature and radiation. The sample locations selected will provide a leading indication of the condition of all structural sealants within the scope of this activity. No actions are taken as part of this program to trend inspection results. For McGuire, this new one-time inspection will be completed following issuance of the renewed operating licenses for McGuire Nuclear Station, and by June 12, 2021 (the end of the initial license of McGuire, Unit 1). For Catawba, this new one-time inspection will be completed following issuance of the renewed operating licenses for Catawba Nuclear Station, and by December 6, 2024 (the end of the initial license of

Catawba, Unit 1). The staff finds that the one-time visual inspection of the structural sealants will confirm that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation. If inspections are not acceptable, specific corrective actions will be implemented by the applicant, in accordance with the corrective action program, to ensure the component intended function will be maintained during the period of extended operation.

[Acceptance Criteria] The acceptance criteria for the Ventilation Area Pressure Boundary Sealants Inspection is no unacceptable cracking or shrinkage that could result in the loss of the intended function of the structural sealant as determined by engineering evaluation. The staff finds this acceptance criterion adequate because it ensures that the condition of the sealant will be adequately evaluated, such that the intended function of the sealant will be maintained.

[Operating Experience] The Ventilation Area Pressure Boundary Sealants Inspection is a new one-time inspection activity for which there is no operating experience. However, similar visual inspections have been performed as part of the Inspection Program for Civil Engineering Structures and Components which has been found to be an acceptable aging management program for license renewal by the staff. The Ventilation Area Pressure Boundary Sealants Inspection is a new program that will use techniques with demonstrated capability and a proven industry record to detect cracking or shrinkage of seals. The staff finds the applicant's inspection method acceptable.

3.0.3.19.3 FSAR Supplement

The staff has reviewed the FSAR supplement summary description of the Ventilation Area Pressure Boundary Sealants Inspection in the applicant's response to open item 2.3-3, and has confirmed that it contains the appropriate elements of the program.

3.0.3.19.4 Conclusion

The staff reviewed the applicant's November 14, 2002, response to open item 2.3-3. On the basis of this review, the staff finds that there is reasonable assurance that the Ventilation Area Pressure Boundary Sealants Inspection will adequately manage the aging effects such that the intended functions will be maintained in accordance with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.0.4 Quality Assurance Program

The staff reviewed LRA Section B.2, "Program and Activity Attributes," of Appendix B to verify that AMPs were described in accordance with 10 CFR 54.21(a)(3) and 10 CFR 54.21(d). In Section B.2 of LRA Appendix B, the applicant described its quality assurance program information with respect to the various AMP elements. The staff's evaluation of the AMPs focused on how the AMP manages aging effects through the effective incorporation of the following ten elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effect, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The particular aspects reviewed by the staff in this section encompass three quality assurance program attributes:

corrective actions, confirmation process, and administrative controls. These three attributes of the quality assurance program are addressed for all of the applicant's AMPs.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components that are subject to an AMR will be adequately managed to ensure that their intended functions will be maintained in a manner that is consistent with the CLB of the facility throughout the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, those aspects of the aging management process that affect the quality of safety-related SSCs are subject to the quality assurance requirements of Appendix B to 10 CFR Part 50. For non-safety-related SSCs that are subject to an AMR, the existing 10 CFR Part 50, Appendix B, quality assurance program may be used by the applicant to address the attributes of corrective actions, confirmation process, and administrative controls.

3.0.4.1 Technical Information in the Application

In Section B.2 of LRA Appendix B, the applicant provides a general description of the corrective actions, administrative controls, and confirmation process common to aging management programs for SSCs within the scope of license renewal. The applicant's programs and activities that are credited with managing the effects of aging can be divided into new and existing programs. As described in Section B.2 of LRA Appendix B, the applicant uses the following specific attributes to describe these programs and activities:

- Program Scope: An identification of the specific structures or components managed by the program or activity.

- Preventive or Mitigative Actions: A description of the actions taken in the period of extended operation to either prevent aging effects from occurring or mitigate (i.e., lessen or slow down) aging degradation for prevention and mitigation programs. This attribute is not applicable for one-time inspections, condition monitoring, or performance monitoring programs.

- Parameters Monitored or Inspected: A description of what is being monitored or inspected for all inspections and programs. These descriptions include the observable parameters or indicators to be monitored or inspected for each aging effect managed. The observable parameters should be linked to the degradation of the structure or component intended functions in the period of extended operation.

- Detection of Aging Effects: The detection of aging effects should occur before there is a loss of structure and component intended function(s).

- Monitoring and Trending: A description of when, where and how program data are collected (i.e., all aspects of activities to collect data as part of the program). This description includes aspects such as method or technique (e.g., visual, volumetric, surface inspection), frequency, sample size, and timing of new/one-time inspections. This attribute also provides information that links the parameters to be monitored or inspected to the aging effects being managed. Trending is a comparison of the current monitoring results with previous monitoring results in order to make predictions for the future and to initiate actions as necessary.

- Acceptance Criteria: A description of the acceptance criteria for ensuring the structure or component intended function is maintained during the period of extended operation. The acceptance criteria may be based on design or current licensing basis information, as well as established industry codes or standards.

- Corrective Action and Confirmation Process: A description of the actions to be taken in the period of extended operation when the acceptance criteria or standard is not met. The corrective action and confirmation process that is described for each aging management program or activity applies to all structures and components within the scope of the program or activity. In some cases, the program itself includes its own corrective action and confirmation process.

  In other cases, the corrective action process is credited for corrective action and confirmation process. The corrective action process is a formal corrective action program which facilitates the correction of conditions adverse to quality. Corrective actions are documented. Data are periodically reviewed to identify positive or negative changes and to initiate additional actions, as necessary. The corrective action process is implemented by Nuclear System Directives (NSD) 208, "Problem Investigation Process (PIP)," and NSD 223, "Trending of PIP Data."

- Administrative Controls: A description of the administrative structure under which the programs and activities are executed. Examples of various administrative structures include program manuals, nuclear station directives, engineering support documents, plant procedures, and work orders. The administrative controls provide for a review and approval process.

- Operating Experience: The objective evidence that supports the determination that the program or activity provides reasonable assurance that the effects of aging will be adequately managed, such that the structure or component intended function(s) will be maintained consistent with the current licensing basis during the period of extended operation (i.e., 20 years from the end of the initial operating license).

3.0.4.2 Staff Evaluation

The staff evaluated aspects of the applicant's quality assurance program as it relates to the AMP activities defined in LRA Appendix A, "FSAR Supplements," and LRA Appendix B, "Aging Management Activities."

10 CFR 54.21(a)(3) requires a license renewal applicant to demonstrate that the effects of aging on structures and components subject to an aging management review will be adequately managed to ensure that their intended functions will be maintained consistent with the current licensing basis of the facility for the period of extended operation. Consistent with this approach, the applicant's aging management programs should contain the elements of corrective action, confirmation process, and administrative controls in order to ensure proper management of the aging programs.

Subsection B.2.2, "Attribute Definitions," of the LRA Appendix B stated that the applicant relied on the corrective action process as implemented through Nuclear System Directive (NSD) 208, "Problem Investigation Process (PIP)," and NSD 223, "Trending of PIP Data," to satisfy the corrective actions, confirmation process, and administrative controls attributes of the aging management programs that will be implemented at Catawba and McGuire for the period of extended operation.

Consistent with guidance in SRP-LRA, Appendix A, Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position HQMB-1)," license renewal applicants can rely on the existing requirements in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to satisfy these program elements (attributes). However, the Catawba/McGuire LRA did not establish or identify the role of the aforementioned NSDs with respect to the applicant's 10 CFR Part 50, Appendix B, quality assurance program in effect at these facilities.

For non-safety-related structures and components that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50, Appendix B, program to include these structures and components to address corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. In accordance with Appendix A, Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," Section A.2.2, Item 2 to the draft SRP, the applicant should document a commitment to expand the scope of its 10 CFR Part 50, Appendix B, quality assurance program to include non-safety-related structures and components in the FSAR supplement consistent with LRA, Appendix B, Section B.2. By letter dated January 17, 2002, the staff requested, in RAI 2.1-3, the applicant to confirm that NSD 208 and 223 govern the applicant's corrective action program, which is subject to the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." In its response dated March 1, 2002, the applicant confirmed that the applicable scope of the quality assurance program was expanded to include the non-safety-related SSCs within the scope of license renewal. The staff finds that committing to the applicant's quality assurance program for all aging management programs for safety-related and non-safety-related SSCs within the scope of license renewal is an acceptable approach to meeting Branch Technical Position IQMB-1.

In RAI 2.1-3, the staff requested the applicant to describe how the programs described in NSD 208 and NSD 223 would satisfy the requirements of 10 CFR Part 50, Appendix B, for SSCs subject to an aging management program at Catawba and McGuire during the period of extended operation. In its March 1, 2002, response to RAI 2.1-3, the applicant indicated that NSD 208, "Problem Investigation Process," provided a structured approach for a formal corrective program that facilitates the prioritization, evaluation, and correction of conditions adverse to quality, as defined by 10 CFR Part 50, Appendix B. NSD 223, "Trending of PIP Data," provided a process for an effective, structured method for analyzing PIP data. As stated in each aging management program and activity description provided in LRA Appendix B, this same corrective action program is credited for systems, structures, and components whose aging will be managed by these aging management programs and activities at Catawba and McGuire during the period of extended operation. Since the applicant's descriptions of these programs indicate that the programs meet regulations governing the quality assurance program, the staff finds this response acceptable.

3.0.4.3 Programs and Activities, FSAR Supplement

The applicant has provided a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation in FSAR Chapter 18, which also is included in Appendix A, Sections A.1 and A.2, to the LRA. The FSAR supplement provides a brief explanation of the new and existing programs that the applicant will use to manage the effects of aging. The explanation contains a summary of several important attributes of aging management programs, as defined in NEI 95-10 and SRP-LRA, such as inspections and techniques used to identify aging effects.

In conformance with 10 CFR 54.21(d) requirements, the applicant needed to describe how the programs described in NSD 208 and NSD 223 would satisfy the requirements of 10 CFR Part 50, Appendix B, "Quality Assurance Program," for SSCs subject to an aging management program as a commitment in the FSAR supplements for Catawba and McGuire. In its March 1, 2002, response to RAI 2.1-3, the applicant indicated that the following statement would be added to Section 18.1 of the McGuire and Catawba FSAR supplements:

> The PIP NSD 208 provides a structured approach for a formal corrective action program that facilitates the prioritization, evaluation, and correction of conditions adverse to quality, as defined by 10 CFR Part 50, Appendix B. This same corrective action program is credited for systems, structures, and components whose aging will be managed by the aging management programs and activities described herein.

Since the applicant indicated that the FSAR supplements would be updated to reflect the role of NSD 208 and NSD 223 in its 10 CFR Part 50, Appendix B, quality assurance program for SSCs subject to an aging management program during the period of extended operation, the staff finds its response acceptable.

3.0.4.4 Conclusion

The staff finds that the quality assurance attributes are consistent with 10 CFR 54.21(a)(3). Therefore, the applicant's quality assurance description for its aging management programs is acceptable. The staff finds that the applicant's FSAR supplement and update thereto in accordance with the March 1, 2002, response to the staff's RAI provides a sufficient description of the quality assurance programs and attributes and activities for managing the effects of aging.

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

The LRA includes the following reactor coolant mechanical components at Catawba and McGuire that require an AMR:

- reactor coolant piping and associated connections to other support systems (including reactor coolant pumps and inter-connected piping, pipe fittings, valves, and bolting)
- reactor vessels (including the control rod drive mechanisms)
- reactor vessel internals
- pressurizers (including safety relief valves and pressure relief tank)
- steam generators

Each reactor coolant system (RCS) at Catawba and McGuire consists of four primary piping loops interconnected at the reactor vessel. Each loop contains one reactor coolant pump (RCP), one steam generator, valves, and interconnecting piping. The pressurizer, connected to one of the hot legs, provides a means for controlling RCS pressure changes during reactor operations. The RCS also contains piping and components that allow venting of the reactor vessel and pressurizer.

The reactor coolant piping at Catawba and McGuire consists of Class 1 and non-Class 1 components. The applicant describes the system boundaries for the Class 1 RC piping and associated components in Section 2.3.1 of the LRA, "Reactor Coolant System," and for the non-Class 1 components in Section 2.3.3.32 of the LRA, "Reactor Coolant System (non-Class 1 components)." The non-Class 1 portions of the RCS (excluding the RCP motor oil collection sub-system) are relied upon to provide and maintain containment isolation and maintain system pressure boundary integrity. The reactor vessel leak-off lines are included within this set of components and are relied upon only in the event the reactor vessel flange inner seal leaks. The results from AMR for the non-Class 1 portions of the RCS are described in Section 3.3 of the LRA, "Aging Management of Auxiliary Systems," and are summarized in Table 3.3-41 of the LRA. The staff's evaluation of Section 3.3 of the LRA is described in Section 3.3 of this SER.

The applicant describes the results from AMR for the Class 1 portions of the RCS, including the reactor vessels, reactor vessel internals, pressurizers, steam generators, and Class 1 piping, valves, and pumps, in Section 3.1 of the LRA, "Aging Management of Reactor Vessel, Internals, and Reactor Coolant System."

Section 3.1 of the LRA defined the external and internal environments applicable to the reactor vessel, internals, and reactor coolant system as follows—

- Borated Water — Borated water is demineralized water treated with boric acid.
- Treated water — Treated water is demineralized water that may be deareated, treated with a biocide or corrosion inhibitors, or a combination of these treatments. Treated water does not include borated water, which is evaluated separately.
- Reactor Building — The Reactor Building environment is moist air. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.

Table 3.1-1 of the LRA, "Aging Management Review Results - Reactor Coolant System," summarizes the results from AMR for these RCS components. The applicant describes the applicable AMPs for these components in Appendix B of the LRA, "Aging Management Programs and Activities." This section of the SER includes the staff's review of the AMR results presented in Section 3.1 of the LRA and includes the mechanical components for all five RCS subsystems identified above.

3.1.1 Reactor Coolant Class 1 Piping, Valves, and Pump Casings

The Westinghouse-supplied primary piping includes branch connection nozzles and special items, such as resistance temperature detector (RTD) scoop elements, pressurizer spray scoop, sample connection scoop, reactor coolant temperature element installation boss, and the temperature element well itself.

The ASME Class 1 piping includes piping connected to the Westinghouse-supplied primary loop piping out to and including (1) the outermost containment isolation valve in piping which penetrates primary containment, or (2) the second of two valves normally closed during normal reactor operation in piping which does not penetrate primary containment. Some branch connections and instrument connections in the RCS are equipped with 3/8 inch ID flow restricting orifices that limit the maximum flow from a break downstream of the flow restrictor to below the makeup capability of the RCS. This orifice is used to establish the division from Class 1 to Class 2 instead of double isolation valves.

For Class 1 valves, the pressure-retaining portion of the component consists of the valve body, bonnet, and closure bolting. The valves are welded in place, with the exception of the pressurizer safety valves that have flanged connections. For the reactor coolant pumps, the pressure-retaining portion includes the pump casing, the main closure flange, the thermal barrier heat exchanger within the RCP, the RCP seals, and the pressure-retaining bolting.

3.1.1.1 Technical Information in the Application

The applicant identifies the Class 1 RCS piping, valves, and pumps within the scope of license renewal in Section 2.3.1.2 of the LRA. In Section 3.1 of the application, the applicant describes its AMR process for ASME Code Class 1 components and the aging management programs (AMPs) that will be used to manage aging effects in these components during the periods of extended operation for the McGuire and Catawba units. In Table 3.1-1 of the application, the applicant identifies that the following Class 1 RCS piping, valves, and pumps within the scope of license renewal require aging management reviews:

- the Westinghouse-supplied primary loop Class 1 piping of the RCS pressure boundary that are connected to the reactor vessel, the steam generators (primary side), and the RCP
- the Duke-designed Class 1 piping of other support systems that are attached to the primary loop piping
- pressure boundary portion of Class 1 valves (bodies and bonnets, bolting)
- pressure boundary portion of the RCP (casing, main closure flange, thermal barrier heat exchanger and bolting)

The applicant described its AMR of the Class 1 piping and associated components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," and in Table 3.1-1 of the application. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging for the RC Class 1 piping, valves, and pump casings will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant stated that the RCS Class 1 piping, valve, and pump components within the scope of license renewal have been designed to meet the requirements of ASME Boiler and Pressure Vessel Code, Section III, Subsection NB for Class 1 components. The predominant material of construction for the Class 1 components, including piping and pipe fittings, is stainless steel, including cast austenitic stainless steel (CASS). The internal surfaces of all Class 1 piping and associated components wetted by borated water are stainless steel. Some bolting and exterior surfaces of the pressure boundary components are identified as carbon or low-alloy steel. Design and welding considerations in the selection of materials for RCS components reduce the susceptibility of Class 1 piping and component materials to sensitization.

The Class 1 piping and associated components that are within the scope of license renewal are internally exposed to borated reactor coolant water at approximately 315.6 °C (600 °F) and 15.41 MPa (2235 psig). These components are located in the reactor building (i.e., containment) and are externally exposed to an air environment. External surfaces near mechanical piping connections (e.g., flanges) may also be exposed to borated water leakage. The thermal barrier heat exchangers for the RC pumps are also exposed to treated water.

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to Class 1 piping and associated components. However, Section 4.0 of the LRA includes the following TLAAs applicable to RC piping and associated components:

- metal fatigue for ASME Class 1 components
- RCP flywheel fatigue
- leak-before-break analyses

3.1.1.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies the following aging effects for the RCS Class 1 piping and associated components that are subject to an AMR:

- cracking
- loss of material
- reduction in fracture toughness
- loss of preload

3.1.1.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies three AMPs to manage the aging effects associated with the RCS Class 1 piping and associated components. The AMPs are:

- Chemistry Control Program
- Fluid Leak Management program
- ISI Plan

The applicant stated that these AMPs are "equivalent or similar to the corresponding program/activity that has been previously reviewed and found acceptable by the staff during the Oconee License Renewal review, as documented in NUREG-1723." The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the RCS Class 1 piping and associated components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Sections 3.1.1 and 3.1.2, LRA Table 3.1-1, and pertinent sections of LRA Appendices A and B regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RCS Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Table 3.1-1 of the LRA lists the Class 1 portions of the RCS piping and associated pressure boundary components that are within the scope of the license renewal and require aging management reviews, identifies the aging effects that require management for these components, and identifies the aging management programs that will be used to manage these effects.

3.1.1.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RCS piping and associated pressure boundary components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

The material of construction for the RCS Class 1 piping and associated components subject to an AMR is primarily stainless steel (including CASS) for pipe fittings, pump casings, and valve bodies. Carbon steel and low-alloy steel are used for RCP main flange bolting. Most RCS piping and associated components are exposed to borated water, treated water, and/or air. The applicant performed a review of industry experience and NRC generic communications relative to the RC piping and associated components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This review also included a review of plant-specific operating experience at both plants. Table 3.1-1 of the LRA identifies that the following aging effects are applicable to the RCS Class 1 piping and associated components requiring AMRs:

- cracking and loss of material of stainless steel components (including CASS) in borated water (internal surfaces)
- loss of material from carbon steel and low-alloy steel components in the reactor building environment (external surfaces)
- reduction in fracture toughness of CASS components (including valve bodies and bonnets, and the CASS McGuire 1 27.5" ID Loop B elbow) in a high-temperature borated water environment
- loss of preload of ASME Class 1 stainless steel and low-alloy steel bolting in the reactor building (i.e., air) environment

Loss of material due to erosion, or general corrosion, is not normally an issue for austenitic stainless steel (including CASS) RCS piping, pump, and valve components because the materials are normally inherently tough and resistant to general corrosion; however, loss of material may be an applicable effect for these components under wet conditions if the components have creviced areas that may be exposed to the fluids. Loss of material in the stainless steel components can occur if the components are subject to wear. The applicant has identified that loss of material is an applicable aging effect for all stainless steel Class 1 RCS piping, pump, and valve components that are exposed on their interior surfaces to borated or treated water environments. This is acceptable because it conservatively accounts for loss of material that could be induced by these aging mechanisms, even though these components do not normally have creviced areas or are not normally subject to wear.

The RCP main flange bolting made out of low-alloy steel (ferritic fasteners) is susceptible to loss of material due to corrosion. The applicant has identified that loss of material due to boric acid-induced corrosion, and specifically due to potential leakage of boric acid to external surfaces of Class 1 RCS components made from carbon or low-alloy steel (including bolted connections, and integral attachments and supports), is a potential aging effect requiring aging management. This is consistent with the staff's discussion of boric acid corrosion events that have occurred in the industry and that are summarized in NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants." The applicant's identification that loss of material is an applicable effect for Class 1 RCS components made from carbon steel or low-alloy steel is acceptable because it agrees with the staff's determination in NUREG/CR-5576 that loss of material resulting from postulated leakage of the primary coolant (i.e., postulated borated water leakage) is an applicable aging effect for PWR RCS components made from carbon steel or low-alloy steel.

Irradiation embrittlement is not a concern for the RCS piping and associated components because the expected neutron fluence is much less than the threshold level at which changes in properties of the material would occur. However, the applicant has identified that CASS components may be susceptible to loss of fracture toughness as a result of thermal aging. The loss in fracture toughness reduces the critical flaw sizes for CASS components. Components fabricated from CASS that have delta ferrite levels below the susceptibility screening criteria have adequate fracture toughness and do not require any supplemental inspection. As a result of thermal embrittlement, components that have a delta ferrite level exceeding the screening criterion may not have adequate fracture toughness and require additional evaluation or examination. The applicant evaluated all RC piping components (i.e., piping components, valve bodies, and RCP casing and main flanges) fabricated from CASS using the criteria delineated in the May 19, 2000, letter to NEI from NRC. Based on this evaluation, the McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow is the only ASME Class 1 piping component that exceeds the NRC-established threshold for susceptibility to thermal embrittlement and requires aging management. This is in accordance with the staff's analysis in its Interim Staff Guidance on CASS that was issued by NRC on May 19, 2000.[2] The applicant's identification that loss of fracture toughness is an applicable effect only for McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow made from CASS is acceptable to the staff because the applicant's inclusion of this aging effect for the McGuire 1, Primary Loop, 27½ inch ID, Loop B cold leg elbow, and omission of this effect for other CASS RCS piping components at McGuire and Catawba, has been based on the analytical methods for evaluating CASS RCS components for thermal aging, as given in the interim staff guidance that was issued in to the NEI and nuclear power industry in May 2001.

The RCS piping and pipe fittings, valve bodies larger than 4-inch nominal pipe size, and the RCP pressure boundary closure components may be susceptible to cracking by thermal fatigue. The applicant addresses this issue as a time-limited aging analysis (TLAA) in Section 4.3 of the application. The staff's evaluation of this TLAA is documented in Section 4.3 of this application.

Austenitic stainless steel is known to be susceptible to stress corrosion cracking if the external surface of the pipe or component comes in contact with halogen levels exceeding 150 ppb or sulfate levels exceeding 100 ppb. The applicant has identified in Table 3.1-1 of the application that cracking is an applicable effect for Class 1 stainless steel piping, valve, or pump components exposed to borated/treated water environments. Although the McGuire UFSAR, Section 5.2.3.3, and the Catawba UFSAR, Section 5.2.3.2.3, state that stress corrosion cracking of the austenitic stainless steel is not a concern because exposure to halogen or sulfates is unlikely, the staff concurs that halogen-induced stress corrosion cracking is a potential aging effect for austenitic stainless steel components that are exposed to borated/treated water environments. The applicant's identification of cracking as an applicable effect for austenitic stainless steel RCS piping components is acceptable because the scope of this general classification covers cracking of stainless steel components that could be induced by both stress corrosion and by thermal fatigue. Thermal fatigue of the RCS piping components is further assessed by the staff in Section 4.3 of this SER.

The applicant has identified that loss of preload due to stress relaxation is an aging effect applicable for bolted closures on the reactor coolant pumps (RCPs) and RCS valves. This is acceptable to the staff because it is in agreement with Table 3.1-1 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," which identifies that loss of preload is an applicable effect for bolted connections in the RCS.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the

---

[2] Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,* Project No. 690, dated May 2000.

applicant has identified all aging effects that are applicable for the Class 1 portion of the RC piping and associated components.

3.1.1.2.2 Aging Management Programs

The applicant identified existing programs for managing aging effects for the RCS Class 1 piping and associated components during the license renewal term. The applicant identified the following AMPs for managing the aging effects associated with the Class 1 RCS piping, pumps, and valves:

- Fluid Leak Management Program for the external surfaces of ferritic carbon steel or low-alloy steel components that could be potentially exposed to borated water leakage
- Chemistry Control Program and the ISI Plan for CASS components and stainless steel piping, fittings, and branch connections
- Chemistry Control Program alone for stainless steel orifices, valve bodies and bonnets, and thermal barrier heat exchanger tubing

The Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, and specifically for those made out of carbon steel or low-alloy steel. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0.

For the Class 1 RCS piping components, the ISI Plan (Section B.3.20 of LRA Appendix B) manages the aging effects of loss of material, cracking, gross loss of preload, and gross reduction in fracture toughness. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsections IWB. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. The ISI Plan also indirectly monitors for loss of fracture toughness in CASS Class 1 components that are susceptible to thermal aging (i.e., the McGuire 1, Primary Loop, 27½ inch ID Loop B cold leg elbow). The ISI plan is credited with managing the aging effects of several components in different structures and systems, and is therefore considered a common aging management program. This is discussed in detail in the following paragraph. The staff has evaluated this common AMP and, with the resolution of open item 3.0.3.10.2-1 pertaining to volumetric examination of small-bore piping, found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The McGuire 1, Primary Loop, 27½ inch ID Loop B, CASS cold leg elbow is fabricated from SA-351 CF8, is statically cast, and contains no niobium. The ferrite number is calculated at 22 percent using Hull's equivalent factors. As part of the ISI plan, the McGuire 1 cold leg elbow is included in the ASME Section XI, Subsection IWB and IWC inspections, in Section B.3.20.1 of the LRA. The applicant has stated it will perform an augmented inspection with applicable criteria from Code Case N-481 to manage reduction of fracture toughness by thermal embrittlement in the cold leg elbow during the period of extended operation. The staff accepted this Code Case for implementation in Revision 12 of Regulatory Guide 1.147 (May 1999). The augmented inspections will include a VT-2 visual examination of the elbow's exterior surface during the system leakage test that is performed each outage, and a VT-1 visual examination of the welded joints that connect the elbow to adjacent piping segments prior to entering the period of extended operation. These two visual examinations will be repeated in the fifth and sixth ISI intervals. A detailed evaluation to demonstrate the integrity and serviceability of the elbow will be performed by June 12, 2021 (i.e., end of the initial license of McGuire 1).

The Chemistry Control Program (Section B.3.6 of Appendix B to the LRA) provides water quality that is compatible with the materials of construction used in the Class 1 piping and associated components in order to minimize loss of material and cracking. This program is developed based on plant technical specification requirements and on EPRI guidelines, which reflect industry experience. The Chemistry Control Program is credited with managing the aging effects of several components in different structures and systems and is, therefore, considered a common aging management program. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for this system. The staff's evaluation of this AMP is provided in Section 3.0 of this SER. However, the staff identified RAI 3.1.1-1, which addresses how the Chemistry Control Program by itself would be capable of managing cracking in some of the Class 1 RCS piping components that were evaluated by the applicant in Table 3.1-1 of the application. The issue raised in RAI 3.1.1-1, and the steps taken by the applicant to resolve it, is discussed in more detail in the following paragraphs.

In accordance with Table 3.1-1, the applicant identified that the Chemistry Control Program will be used to manage the loss of material and cracking in RCS Class 1 orifices, valve bodies/bonnets, and thermal barrier heat exchanger tubing. By letter dated January 28, 2002, the staff requested, in RAI 3.1.1-1, the applicant to clarify how the aging effects associated with orifices are adequately managed without some verification of the effectiveness of the Chemistry Control Program (e.g., ISI or performance monitoring). In its response dated April 15, 2002, the applicant stated that the Chemistry Control Program maintains the environment in the RCS by controlling contaminants that could lead to loss of material and cracking. The applicant also stated that its basis for concluding that the Chemistry Control Program would be sufficient to manage loss of material and cracking in the orifices was that the applicant's review of pertinent operating experience had not yet identified any failure of these components and, therefore, no supplemental inspection activities would be necessary for managing these aging effects during the periods of extended operation. The staff determined that the applicant's response to RAI 3.1.1-1 did not resolve the issue regarding how the Chemistry Control Program by itself would be sufficient to manage loss of material and cracking in these orifices. The staff therefore concluded that some type of acceptable inspection program would be needed to manage these effects in the orifices as well. The staff's resolution of this issue is addressed in the following three paragraphs.

Table IWB-2500-1 to Section XI of the ASME Boiler and Pressure Vessel Code (henceforth Section XI) provides the following inspection requirements for orifices, valve bodies/bonnets, and tubing:

- Examination Category B-P, All Class 1 Pressure Retaining Components for Class 1 piping, valves and heat exchangers — system leak test and VT-2 visual examination of the pressure retaining boundary every refueling outage
- Examination Categories BM1 and BM2, "Pressure Retaining Welds in Pump Casings and Valve Bodies," and "Pump Casings and Valve Bodies" (respectively)
  - welds in valve bodies less than 4 inches in diameter — surface examination once an ISI inspection interval
  - welds in valve bodies greater or equal to 4 inches in diameter — volumetric examination once an ISI inspection interval
  - valve bodies exceeding 4 inches in diameter — visual VT-3 of the internal surfaces once an inspection interval

Based on these requirements, the staff noted that the ISI Plan for McGuire and Catawba was not credited as an AMP to manage loss of material and cracking in the stainless steel ASME Code Class 1 orifices, valve bodies/bonnets, and thermal barrier heat exchanger tubing in the same manner as it was credited to manage these effects in the McGuire and Catawba ASME Code Class 1 CASS components and Code Class 1 stainless steel piping. By letter dated June 26, 2002, the staff indicated that potential open item 3.1.1-1 was identified to address the unresolved issue raised in RAI 3.1.1-1. In potential open item 3.1.1-1, the staff asked the applicant why it had not credited the ISI Plan for managing these aging effects for ASME Code Class 1 orifices, valve bodies/bonnets, and thermal barrier heat exchanger tubing in the same manner as it had credited the ISI Plan to manage these effects in the ASME Code Class 1 components made from CASS materials and Code Class 1 piping made from austenitic stainless steel. By letter dated July 9, 2002, the applicant stated that it will take the following actions to resolve the issue of aging management for those components where the Chemistry Control Program was identified as the sole program for managing aging effects in these components:

1. Supplement Table 3.1-1 of the application by deleting the line item "Orifices" on page 3.1-7, row 3, and to include these components under the line entry entitled "Pipe and Fittings NPS @ 1 inch" on page 3.1-6, row 5 of the table. (The applicant and noted that both the Chemistry Control Program and Inservice Inspection Plan will manage aging of the piping components.)

2. Supplement Table 3.1-1 of the application by modifying the line item "Forged Stainless Steel Valve Bodies and/or Bonnets" on page 3.1-7, row 4, to add the Inservice Inspection Plan as an additional AMP to the Chemistry Control Program for managing aging in forged stainless steel valve bodies and bonnets.

3. Supplement Table 3.1-1 of the application by modifying the line item "Thermal Barrier Heat Exchanger Piping (Tubing) and Flanges" on page 3.1-8, row 3, to add the Reactor Coolant System Operational Leakage Monitoring Program as an additional AMP to the Chemistry Control Program for managing aging in the thermal barrier heat exchanger piping.

4. Supplement Table 3.1-1 of the application by modifying the line item "Immersion Heater Sheaths" on page 3.1-9, row 3, to add the Inservice Inspection Program as an additional AMP to the Chemistry Control Program for managing aging in the immersion heater sheaths.

The applicant's responses to potential open item 3.1.1-1 provide a justified reclassification or clarification of the classification for the components identified under the scope of the potential open item. These actions also provide an inspection program that is accepted by the NRC and will be used, in addition to the Chemistry Control Program, to manage loss of material and cracking in these components. Based on these considerations, the staff concludes that the issue is resolved.

On the basis of the evaluations above, the staff finds that these AMPs are acceptable for managing the pertinent aging effects and providing assurance that the intended function(s) of the RC Class 1 piping and associated components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.1.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the applicant's April 15, 2002, response to the RAI 3.1.1-1. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RC Class 1 piping and associated components will be adequately managed so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Pressurizers

The McGuire and Catawba reactor units each have one pressurizer connected to the RCS hot leg piping via the surge line and the cold leg piping via the spray line. The pressurizers are vertical, cylindrical vessels with hemispherical top and bottom heads. The spray line and surge line nozzles are provided with thermal sleeves to minimize thermal stresses in the line nozzles. Access to the pressurizers is provided through manway openings near the top of the pressurizers. During normal operation, the pressurizers contain a combination of borated reactor coolant and steam that is maintained at the desired temperature and pressure by the electric heaters and pressurizer spray system. The chemical and volume control system (CVCS) maintains the desired water level in the pressurizer during steady-state operation. Section 2.3.1.3 of the LRA, Section 5.4.10 of the Catawba UFSAR, and Section 5.5.10 of the McGuire UFSAR give a general description of the Westinghouse pressurizers at Duke plants, which are designed in accordance with the ASME Code, Section III.

The pressurizers are designed to accommodate insurges and outsurges caused by the power load transients. During an insurge, the spray system condenses steam to prevent the pressure from reaching the operating point of the power-operated relief valve. A continuous spray flow is provided to ensure that the water chemistry within the pressurizer is consistent with that in the RCS. During an outsurge, water flashes to steam due to the resulting pressure reduction and the automatic actuation of the heaters to keep the pressure above the minimum allowable limit. The design functions of the pressurizers are to maintain the structural integrity of the reactor coolant pressure boundary during steady-state operation and normal heatup and cooldown, and to limit pressure changes, to an allowable range, that are caused by reactor coolant thermal expansion and contraction during normal plant load changes.

3.1.2.1 Technical Information in the Application

The applicant described its AMR of the pressurizer sub-components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's responses to RAI 3.1.2-1, 3.1.2-2, 3.1.2-3, and 2.3.2.7-1, dated April 15, 2002. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging for the pressurizers will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The shell, lower and upper heads, and manway are fabricated from carbon steel and low-alloy steel, and are clad with austenitic stainless steel on all internal surfaces exposed to the reactor coolant. This provides corrosion resistance to the borated reactor coolant. The support skirt and flange are fabricated from carbon steel. The material for the surge, spray, relief, and safety nozzles is low-alloy steel clad with stainless steel. As indicated in Westinghouse WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," Duke pressurizer safe ends are constructed from stainless steel and welded to the nozzles with Inconel 82/182. The nozzles are buttered with Inconel 182 and post-weld heat treated (PWHT). Then, the safe ends are welded to the buttering with Inconel 82/182 with no subsequent PWHT. The heater well nozzles are stainless steel forged penetrations through which the immersion heaters are installed. The instrument nozzles are fabricated assemblies made from a stainless steel tube and a stainless steel forged coupling for interfacing with the connecting piping. In the applicant's response to RAI 2.3.2.7-1, dated April 15, 2002, the applicant added the pressurizer spray nozzle head to the scope of license renewal for the McGuire and Catawba nuclear units. The spray nozzle is fabricated from cast austenitic stainless steel (CASS) and is exposed to internal and external borated water environments.

The internal environments include borated water and steam at a maximum pressure of 17.13 MPa (2485 psig) and a maximum temperature of 360 °C (680 °F). The external environments include air, as well as borated water at coolant leakage locations in the pressurizer.

3.1.2.1.1 Aging Effects

In Table 3.1-2 of the LRA, the applicant identifies that the following aging effects are applicable to the pressurizer sub-components that require aging management:

- cracking
- loss of material
- loss of preload

In the applicant's response to RAI 2.3.2.7-1, the applicant added cracking as an applicable aging effect for the CASS pressurizer spray heads brought within the scope of license renewal by the applicant.

3.1.2.1.2 Aging Management Programs

The applicant identified existing programs for managing aging effects for the pressurizer sub-components during the license renewal term. The following existing AMPs are identified in the application:

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review

In the applicant's response to RAI 2.3.2.7-1, the applicant proposed two programs to manage cracking in the CASS pressurizer spray heads brought within the scope of license renewal: (1) the Chemistry Control Program, and (2) a new program, the Pressurizer Spray Head Examination.

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the pressurizer sub-components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to pressurizer sub-components. However, Section 4.0 of the LRA identifies a TLAA to address metal fatigue for ASME Class 1 components, which applies to pressurizer sub-components.

3.1.2.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.1.1 and 3.1.2, and in Table 3.1-1 of the LRA, and pertinent sections of Appendices A and B to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the pressurizer components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

In Table 3.1-1 of the LRA, the applicant lists the pressurizer sub-components within the scope of the license renewal with their intended functions, material groups, and environment. The table also identifies the aging effects requiring management, and the plant-specific AMPs required to manage these aging effects, during the period of extended operation. The list of components within the scope of license renewal are grouped in accordance with their component types.

3.1.2.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the pressurizer sub-components to provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Catawba and McGuire. This also included the plant-specific operating experience at both subject plants.

The materials of construction for the pressurizer are stainless steel, low-alloy steel, and carbon steel. The pressurizer surge, spray, relief, and safety nozzles are all buttered with nickel-based alloy (Alloy 82/182) weld build up. All surfaces of the pressurizer shells, lower and upper heads, and manways are fabricated from low-alloy and carbon steel, and are clad with stainless steel, which provides corrosion resistance to borated water exposure. In Table 3.1-1 of the LRA, the applicant identified the following aging effects associated with pressurizer sub-components that require aging management:

- cracking from the interior surfaces of nickel-based pressurizer sub-components that are exposed to a borated water/steam environment (including the applicant's AMR results for the pressurizer surge nozzle and spray nozzle thermal sleeve attachment welds fabricated from nickel-based alloy filler materials, as provided in the applicant's letter of November 21, 2002)
- loss of material and cracking from the interior surfaces of stainless steel pressurizer sub-components in a borated water/steam environment
- cracking and reduction in fracture toughness as applicable aging effect for CASS pressurizer spray heads that are exposed to a borated water/steam environment, as identified the applicant's response to RAI 2.3.2.7-1
- loss of material from the exterior surfaces of carbon steel and low-alloy steel sub-components that could potentially be exposed to borated water leakage environments
- loss of material, cracking, and loss of preload of the manway cover alloy steel bolts and studs
- loss of material and cracking in highly-stressed carbon steel and low-alloy steel pressurizer integral attachments (supports) that are exposed to the reactor building environment

Loss of material may occur in pressurizer components under certain conditions. Industry experience demonstrates that exposure to borated water may cause corrosion and lead to a loss of material in carbon or low-alloy steel RCS pressure boundary components, including the carbon/low-alloy steel pressurizer shells and heads, the high-strength alloy steel bolting materials, the carbon steel support skirt and flange, and the alloy steel integral attachments (supports). NUREG/CR-5576 provides a summary of boric acid wastage events that had occurred in low-alloy steel or carbon steel primary pressure boundary components of domestic PWRs through 1990. Since 1990, other significant boric acid wastage events have occurred in the industry, including the boric acid wastage event of the Davis-Besse reactor vessel head that was reported in March of 2002. To be consistent with this industry experience, the applicant has appropriately identified that loss of material is an applicable aging effect for the exterior surfaces of carbon or low-alloy steel pressurizer components that could be subjected to potential borated water leakage from the pressurizer. The interior surfaces of the carbon steel/alloy steel portions of the McGuire and Catawba pressurizer shells and heads are not exposed to the borated water/steam environment (i.e., they are clad with austenitic stainless steel to prevent exposure to the coolant) and, therefore, are not subject to boric acid-induced loss of material in this manner. The applicant's identification that loss of material is an applicable effect for pressurizer components made from carbon or low-alloy steel is acceptable because it agrees with the staff's determination in NUREG/CR-5576 that loss of material resulting from postulated leakage of the primary coolant (i.e., postulated borated water leakage) is an applicable aging effect for PWR RCS components made from carbon steel or low-alloy steel.

Crevice corrosion and pitting corrosion are mechanisms that may lead to a loss of material of stainless steel or stainless steel-clad components that are under creviced, borated conditions, and that require aging management for stainless steel in borated water. In WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," the Westinghouse Owners Group (WOG) concluded that loss of material from stainless steel or stainless steel-clad pressurizer components was not an applicable effect for Westinghouse PWRs due to the implementation of hydrogen water chemistry used to minimize the levels of dissolved oxygen in the primary coolant (i.e., borated water). In its safety evaluation on WCAP-14574-A, the staff concluded that the potential to develop crevice corrosion and pitting corrosion would be minimized if an applicant for renewal would confirm that it was implementing hydrogen water chemistry practices at its facilities. The applicant identified that it uses the Chemistry Control Program and hydrogen injection to maintain the hydrogen concentrations in the reactor coolant within specific limits, and to minimize the levels of dissolved oxygen in the coolant that otherwise could create environments conducive to the loss of material by crevice corrosion or stress corrosion cracking. For conservatism, however, the applicant has identified loss of material as an applicable aging effect for pressurizer components that are clad with stainless steel and for stainless steel pressurizer components that may have creviced areas and are exposed to the borated reactor coolant (e.g., heater immersion sheaths or stainless steel sleeves for the pressurizer surge and spray nozzles, etc.). This is acceptable to the staff because the applicant has identified loss of material as an applicable effect for stainless steel pressurizer components that may be exposed to the borated coolant under creviced conditions, and has taken a conservative approach relative to the staff's assessment in its SE on WCAP-14574-A.

Cracking of the pressurizer components may be induced by two primary aging mechanisms: thermal fatigue and stress corrosion cracking. Thermal fatigue is a phenomenon that may lead to cracking due to thermal-cyclical loading conditions. The applicant has appropriately identified that the pressurizer support skirt and flange, upper and lower heads, relief nozzle, safety nozzle, shell, spray nozzle, surge nozzle, instrument nozzle, manway and manway bolts/studs, immersion heater, seismic support lugs, and valve support bracket lugs are all susceptible to fatigue-related cracking. The applicant's thermal fatigue analysis for these pressurizer components is provided in LRA Section 4.3; the staff's evaluation is documented in Section 4.3 of this SER.

Pressurizer components made from austenitic stainless steel or nickel-based alloys, mainly the pressurizer cladding, nozzles, and thermal sleeves, are susceptible to SCC in the presence of borated water or steam. In Section 3.1 of the LRA, the applicant did not specifically address whether the potential exists for existing cracks in the pressurizer cladding, or associated weldments, to grow (as a result of thermal fatigue-induced crack growth) through the cladding and into the ferritic portions of the pressurizer sub-components to which the cladding is joined. The staff is concerned that intergranular stress corrosion cracking (IGSCC) in the heat-affected zones of 304 stainless steel supports that are welded to the pressurizer cladding, could grow as a result of thermal fatigue into the adjacent pressure boundary during the license renewal term. For the issue regarding whether IGSCC could initiate in the cladding weldments, the staff considers that these weldments would not require aging management in the period of extended operation, if an applicant could provide reasonable justification that sensitization has not occurred in these welds during the fabrication of these components.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-1, the applicant to discuss whether thermal fatigue-induced crack initiation and growth is an issue for the ferritic pressurizer components that are clad austenitic stainless steel, and specifically whether thermal fatigue-induced growth of an existing crack into the ferritic base material beneath the clad, or into the welds joining the cladding to the pressurizer base metals, is an applicable effect that requires aging management. In its response dated April 15, 2002, the applicant stated that, while the cladding and the welds that attach internal items to the pressurizer cladding may be sensitized, the location that is most likely to experience cracking by thermal fatigue is the welded joint that connects the surge nozzle to the pressurizer shell. The applicant also stated that, if cracking were to occur at the surface of the surge nozzle cladding and propagate into the base metal, volumetric examinations of the cladding performed in accordance with ASME Section XI, Examination Category B-D, would detect the flaw prior to loss of the pressurizer intended function. Based on the fatigue usage factors for the pressurizer shell and its nozzles, the staff considers this location to be the most limiting location for thermal fatigue-induced crack growth. The staff concludes that the applicant's implementation of volumetric examinations of this location will be sufficient to identify whether thermal fatigue-induced crack growth is an issue for the ferritic pressurizer components that are clad with stainless steel. The staff therefore considers RAI 3.1.2-1 to be resolved.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-2, the applicant to discuss how the implementation of plant-specific procedures and quality assurance requirements, if any, for the welding and testing of austenitic stainless steel provides reasonable assurance that sensitization and cracking had not occurred in the pressurizer cladding welds. In its response dated April 15, 2002, the applicant stated that the possibility that sensitized areas exist in the 304 stainless steel supports or their welds cannot be precluded even with controlled material selection and the implementation of manufacturing processes that minimize sensitization. Furthermore, the Chemistry Control Program, which precludes stress corrosion cracking in other PWR primary system materials, is also effective in preventing stress corrosion cracking in these pressurizer components and welds. The applicant also stated that rigorous control of oxygen and chlorides provides a benign environment that has been shown to be effective both in laboratory experiments and years of operating experience.

The applicant's response to RAI 3.1.2-2 proposes to use an acceptable mitigation strategy (i.e., the Chemistry Control Program) as the basis for precluding crack initiation by stress corrosion in the pressurizer cladding. When taken in context with the applicant's response to RAI 3.1.2-1, the applicant also proposes to inspect the locations in the McGuire and Catawba units that are most likely to experience cracking by thermal fatigue consistent with volumetric examinations performed in accordance with ASME Section XI Category B-D. For the McGuire/Catawba units, this is the weld that joins the surge nozzle and its cladding to the pressurizer shell. This inspection also will provide the applicant with an indication whether stress corrosion cracking has occurred in the pressurizer cladding. Therefore, the staff finds that the applicant's responses to RAIs 3.1.2-1 and 3.1.2-2, when taken together in context, resolve these RAIs because the issue of whether stress corrosion cracking is an issue for the pressurizer cladding will be determined by the applicant using the volumetric inspection technique.

In addition, the applicant stated, in LRA Table 3.1-1, that cracking is an applicable effect for the surfaces of stainless steel or nickel-based pressurizer components (including the cladding for alloy steel pressurizer component clad with austenitic stainless steel) that are exposed to the borated water/steam environment. The staff finds that the applicant's assessment of cracking for these stainless steel or nickel-based alloy pressurizer components is acceptable because (1) the applicant has appropriately identified cracking as an applicable effect for stainless steel and nickel-based pressurizer components, and (2) the applicant has addressed the issue of growth of pre-existing cracks through the cladding into the ferritic (i.e., carbon steel or alloy steel) base metals of the pressurizer.

Stress-induced cracking may occur in the surfaces of high-strength (> 150 ksi yield strength) alloy steel bolting materials (including nut, studs, and washers), and in alloy or carbon steel integral attachments that are under loaded (stressed) conditions and are exposed to the reactor building environment. In its safety evaluation on WCAP-14574-A, dated October 26, 2002, the staff concluded that the potential to develop SCC in alloy steel manway bolts will be minimized, if the yield strength of the material is held to less than 150 ksi, or the hardness is less than 32 on the Rockwell C hardness scale. In lieu of providing documentation that the yield strengths or Rockwell C hardness values for the bolting materials would conform to acceptable values provided in the staff's safety evaluation on WCAP-14574-A, the applicant has identified cracking as an applicable aging effect for the alloy steel pressurizer bolting materials that are exposed to the reactor building environment. The applicant similarly identified cracking as an applicable effect for the exterior surfaces of highly stressed alloy steel and carbon steel pressurizer supports that are exposed to the reactor building environments. The applicant's identification of cracking as an applicable effect for these components is conservative relative to the staff's safety evaluation of WCAP-14574-A, and is therefore acceptable to the staff. Bolted connections in plant systems may also be subject to a loss of preload (loss of mechanical closure integrity) due to the stress relaxation. The applicant has also identified in Table 3.1-1 of the application that loss of preload is one of the three applicable aging effects for the manway cover bolts/studs. The applicant's identification that loss of preload is an applicable effect for the manway cover bolts and studs is acceptable because it is in agreement with Table 3.1-1 of NUREG-1800, which identifies loss of preload due to stress relaxation as an applicable aging effect for bolted manway covers in the RCS.

In its April 15, 2002, response to RAI 2.3.2.7-1, which pertained to the staff's scoping and screening evaluation that is documented in Section 2.3.2.7 of the SER, the applicant added the pressurizer spray nozzle heads to the scope of license renewal for the McGuire and Catawba pressurizers. The pressurizer spray head serves a safety function of pressure control for the RCS but does not serve a pressure boundary function for the RCS. The spray nozzle is fabricated from CASS and is exposed to internal and external borated water environments. In the response to RAI 2.3.2.7-1, the applicant identified that cracking was an applicable effect for the CASS pressurizer spray nozzles. In the McGuire/Catawba application, both loss of material and cracking are applicable effects for other CASS components of the RCS that serve a pressure boundary function and that are exposed to borated water conditions. The staff concludes that loss of material will not significantly affect the spray pattern from the pressurizer spray heads to a point where the spray heads would not be capable of performing their safety function of providing pressure control for the RCS because the McGuire and Catawba pressurizer spray head designs do not use a perforated bottom plate to accomplish the spray function. Loss of material in the spray heads will not, in this case, lead to a loss or significant change in the spray distribution when the pressurizers are called upon to perform their spray functions. Based on this determination, and since this conforms to Table 3.1-1 of NUREG-1800, the staff concludes that only cracking need be identified as an applicable effect for the

CASS pressurizer spray heads within the scope of license renewal, and that the applicant's resolution of RAI 2.3.2.7-1 is acceptable.

According to the following excerpt from NRC Inspection Report Nos. 50-369/02-06, 50-370/02-06, 50-413/02-06, and 50-414/02-06, NRC inspectors identified that the pressurizer surge nozzle and spray nozzle thermal sleeves were not included within the scope of the ISI plans for the McGuire 1 and 2 and Catawba 1 and 2 stations.

> During the review, the inspectors identified the following discrepancies when comparing the ISI Plans with Section B3.20 and Table 3.1-1 of the McGuire and Catawba LRA:
>
> > Table 3.1-1 of the LRA lists the ISI Plan as an aging management program for loss of material and cracking of pressurizer surge and spray nozzle thermal sleeves. The McGuire and Catawba ISI Plans do not include these components.
> >
> > Table 3.1-1 of the LRA lists the ISI Plan as an aging management program for cracking and loss of material of the steam generator divider plates. The McGuire and Catawba ISI plans do not include these components.
>
> In both cases, the ISI plans were not the only aging management programs referenced. The applicant agreed with the discrepancies identified and stated that, for the two components identified, additional aging management reviews would be performed to determine if the programs taken credit for (absent the ISI Plan) were adequate to manage aging of the pressurizer spray and surge nozzle thermal sleeves and the steam generator divider plates.

The staff subsequently determined that the applicant had excluded these components from the scope of license renewal. Since this determination constituted a change to the LRA, the staff requested, in electronic correspondence dated October 23, 2002 (ADAMS Accession No. ML023290487), formal notification of this amendment to the original application submittal. In a letter dated October 28, 2002, the applicant provided the following explanation:

> With respect to the pressurizer surge and spray nozzle thermal sleeves, Table 3.1-1 of the Application groups the thermal sleeves with the nozzles. The nozzles perform a Reactor Coolant System pressure boundary function (§54.4(a)(1)(i)); the thermal sleeves do not. Aging management programs for these nozzles include Inservice Inspection Plan, Chemistry Control Program, Alloy 600 Aging Management Review, and of course the nozzles are within the Thermal Fatigue Management Program discussed in Chapter 4 of the Application. Duke is revising its in-house license renewal engineering specifications to correct the discussion of the thermal sleeves to state that they are not in scope because they do not perform a license renewal function.
>
> The steam generator (SG) divider plate is located in the lower head of each SG and separates the hot leg primary fluid from the cold leg primary fluid. Reactor coolant is located on both sides of the SG divider plate. Clearly it does not perform any function required by §54.4. The Application incorrectly called this a pressure boundary function. The Inspection Report correctly noted that the Inservice Inspection Plan does not include this component within the scope of inspections. Duke is revising its in-house license renewal engineering specifications to correct the discussion of the divider plate to state that it is not in scope because it does not perform a license renewal function as defined by §54.4.
>
> Changes to the in-house license renewal engineering specifications are being made in accordance with the Duke QA program.

The staff was concerned that the applicant had inappropriately concluded that the pressurizer surge and spray nozzle thermal sleeves and steam generator divider plates were not in scope to resolve the discrepancy identified by the NRC inspectors. Therefore, in a letter dated November 13, 2002, the staff expressed its concern that the decision to remove these components from the scope of license renewal involved a significant deviation from the scoping methodology defined in Chapter 2 of the applicant's license renewal application. The staff also expressed concern that the steam generator divider plate may be required to facilitate natural circulation cooldown during certain design basis event. The staff also noted that Table 2-1, "Summary of Subcomponents Requiring Aging Management Review," of WCAP-14574, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," indicated that aging management review is required for pressurizer spray and surge nozzle thermal sleeves.

In a letter dated November 14, 2002, the applicant provided a response that superceded its October 28, 2002, submittal on this item. The applicant stated that it had confirmed that the thermal sleeves for the pressurizer spray and surge nozzles were not included within the scope of Duke's current ISI plans for the McGuire and Catawba reactor units. The applicant's original AMR for these components is given in row 4 of page 3.1-9 of Table 3.1-1 of the LRA, and the scope of the AMR includes both the pressurizer surge and spray nozzle thermal sleeves (both of which are fabricated from stainless steel) and the Alloy 82/182 attachment welds that join the thermal sleeves to the associated nozzles. Therefore, the applicant proposed to credit only the remaining AMPs (Chemistry Control Program, Thermal Fatigue Management Program, and the Alloy 600 Aging Management review) for these components. In a letter dated November 21, 2002, the applicant supplemented the information provided in the letter of November 14, 2002, and modified its AMR for the thermal sleeves that are welded internally to the pressurizer spray nozzles and pressurizer surge nozzles by providing the following separate AMRs for the thermal sleeves and the associated Alloy 182/82 attachment welds:

Component Type	Component Function	Material	Environment	Aging Effect	AMPs
Pressurizer Surge and Spray Nozzle Thermal Sleeves	Note 1	Stainless Steel	Borated Water	Loss of Material Cracking	Chemistry Control AMP
Associated Attachment Welds for the Thermal Sleeves	Note 2	Nickel-based Alloy Weld	Borated Water	Cracking	Chemistry Control AMP Alloy 600 Aging Management Review

Note 1: The pressurizer surge and spray nozzle thermal sleeves support the pressurizer surge and spray nozzles, as stated in the applicant's revised AMR descriptions for the pressurizer surge and spray nozzle assembly (refer to the applicant's letter of November 21, 2002, to the NRC document control desk).
Note 2: The pressurizer surge and spray nozzle thermal sleeve attachment welds could degrade the RCS pressure boundary if cracking were to occur.

The applicant's revised AMR identifies that loss of material and cracking are applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves. This is consistent with the applicant's identification of aging effects for other stainless steel RCS components that are exposed to the primary coolant. The staff has evaluated loss of material and cracking in stainless steel components previously in this SER section, and concludes that these aging effects are applicable to the stainless steel pressurizer surge and spray nozzle thermal sleeves.

The associated attachment welds for the pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 182/82 filler metals. The applicant's revised AMR identifies cracking as the applicable aging effect for the welds. The staff has evaluated cracking in Alloy 600 and Alloy 182/82 materials previously in this section and concludes that cracking is an applicable aging effect for the pressurizer surge and spray nozzle thermal sleeve attachment welds fabricated from Alloy 182/82.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the pressurizer sub-components.

3.1.2.2.2 Aging Management Programs

The applicant identified the following existing programs for managing aging effects identified in Table 3.1-1 as being applicable to the pressurizer sub-components:

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review

The Chemistry Control Program (Section B.3.6 of LRA Appendix B) provides water quality that is compatible with the materials of construction used for the McGuire and Catawba pressurizer components in order to minimize loss of material and cracking. This program is developed based on plant TS requirements and EPRI guidelines, which reflect industry experience. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer sub-components. The staff's evaluation of this AMP is documented in Section 3.0 of this SER. As a result of the applicant's letters of November 14, 2002, and November 21, 2002, the applicant's new AMR for the pressurizer surge and spray nozzle thermal sleeves credits the Chemistry Control Program as the sole AMP for managing loss of material and cracking in the thermal sleeves. The applicant is no longer crediting the ISI plan for managing loss of material and cracking in the pressurizer surge and spray nozzle thermal sleeves. These thermal sleeves do not serve a pressure boundary function for the RCS, but do support the pressurizer surge and spray nozzles by protecting them against thermal cycling. Since the thermal sleeves do not serve a pressure boundary function by themselves, the staff concludes that it is acceptable to use a mitigative program, the Chemistry Control Program, as the basis for managing loss of material and cracking in the pressurizer surge and spray nozzle thermal sleeves.

The Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, specifically for those made out of carbon steel or low-alloy steel. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer sub-components. The staff's evaluation of this AMP is documented in Section 3.0.

For the pressurizer components, the ISI Plan (Section B.3.20 of LRA Appendix B) manages aging effects of loss of material, cracking, and gross loss of preload. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsection IWB. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the pressurizer. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

By letter dated January 28, 2002, the staff requested, in RAI 3.1.2-3, the applicant to clarify how the ISI Plan and Fluid Leak Management Program are sufficient to manage loss of preload of the pressurizer manway bolts and studs. In its response dated April 15, 2002, the applicant stated that the aging effect "loss of preload" that is identified for the pressurizer manway bolts/studs would manifest itself as leakage due to the loss of mechanical closure integrity and that, if there were a loss of mechanical closure integrity, the leakage would be detected by the Fluid Leak Management Program. The pressurizer pressure retaining components, including all bolted closures, are also visually inspected for leakage by the ISI Plan. The applicant's response to RAI 3.1.2-3 provides a valid basis of how the ISI Plan and Fluid Leak Management Program will be used to manage loss of preload in the bolts and studs. The staff concludes that the applicant's response resolves RAI 3.1.2-3. The applicant's basis for using the Fluid Leak Management Program and ISI Plan as the programs for managing loss of preload in the pressurizer manway bolts and studs is acceptable because both of the programs have acceptable inspection-based means of determining whether loosening of the bolted connections in the pressurizer manway covers has occurred.

The Alloy 600 Aging Management Review is presented in Section B.3.1 of LRA Appendix B. The review will be used to determine whether the applicant should augment or change the inspection activities currently proposed to manage cracking in ASME Code Class 1 Alloy 600/690, Alloy 82/182, and Alloy 52/152 locations in the RCS. In response to RAI 2.3.2.7-1, the applicant also proposed to implement a new aging management program, the "Pressurizer Spray Head Examination," to manage the aging effects that the applicant had identified in its response to the RAI as being applicable to the pressurizer spray head. The staff's evaluation of the Alloy 600 Aging Management Review and the Pressurizer Spray Head Examination are documented in the following two sections.

Alloy 600 Aging Management Review

The applicant described its Alloy 600 Aging Management Review in Section 3.1 of LRA Appendix B. The staff reviewed the application to determine whether the applicant had demonstrated that the Alloy 600 Aging Management Review will adequately manage the applicable effects of aging in the plants during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The objective of the applicant's Alloy 600 Aging Management Review (A600 AMR) is to provide general oversight and management of primary water stress corrosion cracking (PWSCC) in nickel-based alloy (Alloy 600) components within the scope of license renewal, and to ensure that nickel-based alloy locations are adequately inspected by the ISI Plan (Section B.3.20 of LRA Appendix B) or other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program (Section B.3.9 of LRA Appendix B), the Reactor Vessel Internals Inspection Program (Section B.3.27 of LRA Appendix B), and the Steam Generator Integrity Program (Section B.3.31 of LRA Appendix B).

The applicant stated that the A600 AMR will identify Alloy 600/690, 82/182, and 52/152 locations. A ranking of susceptibility to primary water stress corrosion cracking (PWSCC) will be performed for the nickel-based alloy locations. The applicant indicated that it will perform a review to ensure that nickel-based alloy locations are adequately inspected by the ISI Plan or other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, or the Steam Generator Integrity Program. This applicant's review will utilize industry and Duke-specific operating experience. The inspection method and frequency of inspection for the Alloy 600/690, 82/182, and 52/152 locations for the period of extended operation will be adjusted as needed, based on the results of this review. In addition, the applicant will develop supplemental inspection scopes for the period of extended operation as necessary.

For McGuire, the applicant stated that this review will be completed following issuance of the renewed operating licenses for the McGuire Nuclear Station, and by June 12, 2021, which corresponds to the end of the initial 40-year license period for McGuire 1. For Catawba, the applicant stated this review will be completed following issuance of the renewed operating licenses for the Catawba Nuclear Station, and by December 6, 2024, which corresponds to the end of the initial 40-year license period for Catawba 1. The applicant indicated that the results of these reviews will be incorporated into the unit-specific ISI plans for the ISI intervals during the period of extended operation.

The applicant did not describe the A600 AMR in terms of the specific program attributes that were defined in Section B.2.2 of Appendix B to the McGuire/Catawba applications. The staff therefore could not focus its evaluation of the A600 AMR on the following seven program attributes:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

By letter dated January 28, 2002, the staff requested, in RAI B.3.1-1, that the applicant confirm the following aspects of the A600 AMR:

1. The A600 AMR is simply a susceptibility ranking review calculation that will be used to determine whether inspection techniques proposed in aging management programs for managing aging effects in Alloy 600 components of the reactor coolant pressure boundary components (including reactor vessel internal components) should be enhanced or augmented; and

2. The program attributes are normally provided in the application for programs that are listed in the LRA as aging management programs. Since the A600 AMR is simply a review program, the program attributes for the review are not necessary.

In its response dated April 15, 2002, the applicant stated that the staff's description of the A600 AMR is correct. The purpose of the A600 AMR is simply to ensure that nickel-based alloy locations are adequately inspected by either the ISI Plan or other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and/or Steam Generator Surveillance Program. These aging management programs are described in detail in Sections B.3.20, B.3.9, B.3.27, and B.3.31 of LRA Appendix B, respectively, and evaluated in Sections 3.0.3.9.1, 3.1.3.2.2.1, 3.1.4.2.2.1, and 3.1.5.2.2.1 of this SER, respectively.

The applicant stated that the results of the A600 AMR will be used as an applicant initiative to determine whether a change to the inspection method and frequency of inspection criteria for Alloy 600/690, 82/182, and 52/152 locations is necessary during the periods of extended operation. It needs to be emphasized that the applicant uses inspection criteria in the ISI Plan, the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and the Steam Generator Surveillance Program as the basis for inspecting Alloy 600 locations in the RCS piping, RV and RV head penetration nozzles, RV internals, and SGs. The applicant's Appendix B corrective actions program adequately addresses findings that result from inspections performed in accordance with these inspection programs. The applicant has emphasized that A600 AMR will only to be used as an additional tool for determining whether the requirements in these programs for inspecting the Alloy 600 locations of the McGuire and Catawba nuclear plants need to be augmented. Since the corrective actions program is already in effect at the McGuire and Catawba stations, and since implementation of the corrective actions program will provide the applicant with a basis for augmenting the inspection requirements for RCS Alloy 600 locations should cracking or loss of material be detected, the staff finds that the A600 AMR is an acceptable tool for augmenting the inspection requirements in the ISI Plan, the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and the Steam Generator Surveillance Program. There is one exception to this. In letters dated November 14, 2002, and November 21, 2002, the applicant provided a revised AMR for the Alloy 182/82 attachment welds for the pressurizer surge and spray nozzle thermal sleeves. In these letters, the applicant credited the Chemistry Control Program and the A600 AMR for managing the aging effect of cracking. The applicant has stated the A600 AMR would be used to rank the susceptibility of the pressurizer surge and spray nozzle thermal sleeve welds to cracking. Based on these rankings, an augmented inspection program for these welds may be implemented.

In its letter dated November 21, 2002, the applicant augmented its FSAR supplement summary description of the Alloy 600 AMR by committing to provide the A600 AMR rankings for the pressurizer surge and spray nozzle thermal sleeve attachment welds to the staff for review prior to entering into the extended periods of operation for the McGuire and Catawba units. This will provide the staff with an opportunity to review the ranking for welds to determine whether an augmented program is necessary. The applicant's specific commitments to the FSAR supplement descriptions for the McGuire and Catawba A600 AMRs are given in the following paragraph. The staff concludes that the applicant's proposal to use the A600 AMR and the Chemistry Control Program as the bases for managing cracking in the pressurizer surge and spray nozzle thermal sleeve attachment welds is acceptable because the applicant has committed to provide the susceptibility rankings for the welds for NRC staff review, and because an augmented inspection program will be created if the rankings for the attachment welds warrant it.

FSAR Supplement: The applicant's FSAR supplement for the A600 AMR is provided in Section 18.2.1 of Appendix A of the LRA, and provides an overview of the review as described in Section B.3.1 of LRA Appendix B. In the letter dated November 21, 2002, the applicant provided the following commitments regarding the A600 AMR:

> Following the completion of the *Alloy 600 Aging Management Review* on each station, Duke will submit to the NRC the results for the pressurizer surge and spray nozzle thermal sleeves attachment welds. Duke understands that the staff will review these results and may request additional information to gain an understanding of the results.
>
> For McGuire, the results for the pressurizer surge and spray nozzle thermal sleeves attachment welds will be submitted to the NRC following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 (the end of the initial license of McGuire Unit 1).
>
> For Catawba, the results for the pressurizer surge and spray nozzle thermal sleeves attachment welds will be submitted to the NRC following issuance of renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 (the end of the initial license of Catawba Unit 1).

The applicant's FSAR supplement descriptions for the A600 AMR reflect the commitment to provide susceptibility rankings for the pressurizer surge and spray nozzle thermal sleeve attachment welds to the staff for review. Based on the applicant's response to the staff's request for additional information, as documented in the letter dated April 15, 2002, and the supplemental information provided in the applicant's letter of November 21, 2002, the FSAR supplement for the A600 AMR is acceptable.

The staff reviewed the information provided in Section 3.1 of LRA Appendix B. In addition, the staff considered the applicant's responses to the staff's RAIs provided in a letter to the NRC dated April 15, 2002. The applicant's current description of the A600 AMR provides a sufficient basis as to how the review will be used to determine whether the inspection frequencies, methods, and criteria specified in the ISI Plan for inspecting Alloy 600/690, 82/182, and 52/152 locations or in other existing programs, such as the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, the Reactor Vessel Internals Inspection Program, and the Steam Generator Integrity Program, need to be augmented or enhanced. The staff's evaluation of these programs is documented in Sections 3.0.3.9.1, 3.1.3.2.2.1, 3.1.4.2.2.1, and 3.1.5.2.2.1 of this SER, respectively. The staff's assessment of the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, as given in Section 3.1.3.2.2.1 of this SER, addresses the implications of the Oconee CRDM nozzle cracking events, the Davis-Besse boric acid wastage event, and NRC Bulletins 2001-001 and 2002-01 on the acceptability of the Control Rod Drive Mechanism and Other Vessel Head Penetration Program, and on the assurance of the structural integrity of the McGuire/Catawba RV head penetration nozzles during the extended periods of operation for the units. When implemented, the A600 AMR should incorporate the implications of the Davis-Besse boric acid wastage event into the review process. Resolution of this current operating issue is being pursued by the staff under 10 CFR Part 50. The outcome of this resolution will dictate the nature and extent to which the A600 AMR will be modified to address this issue.

On the basis of its review, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed by the A600 AMR so that there is reasonable assurance that the intended function(s) of the pressurizer sub-components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Pressurizer Spray Head Examination

The applicant describes the Pressurizer Spray Head Examination in its April 15, 2002, response to RAI 2.3.2.7-1. In its response, the applicant describes its evaluation of this program in terms of aging management program attributes provided in the Standard Review Plan for license renewal. The applicant credits this program as managing the effects of aging for the pressurizer spray heads for the McGuire and Catawba units.

The staff reviewed the applicant's description of the program to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in selected pressurizer spray heads during the periods of extended operation, as required by 10 CFR 54.21(a)(3).

The purpose of the pressurizer spray head examination is to characterize any cracking in the CASS pressurizer spray heads for the McGuire and Catawba units. The applicant states that it plans to inspect the operating unit with the most hours at operating temperature among the four units at McGuire and Catawba, and that McGuire 1 is expected to be the lead unit for this inspection. The applicant states that, after the results of the McGuire 1 inspection are evaluated, additional examinations may be performed on the pressurizer spray heads at McGuire 2 and Catawba 1 and 2.

The staff evaluated the pressurizer spray head examination, as described in the applicant's response to RAI 2.3.2.7-1, on the following seven program attributes for the program:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Pressurizer Spray Head Examination is documented in Section 3.0.4 of this SER.

[Scope of Program] The applicant stated that the scope of the Pressurizer Spray Head Examination is the internal spray head of the McGuire and Catawba pressurizers. The examination is a new one-time inspection of the McGuire 1 pressurizer spray head (which will be representative of the other units' pressurizer spray heads) to ensure that cracking of the spray heads will not lead to a loss of pressure control function for these components. The staff's basis for why the McGuire 1 pressurizer spray head is representative of the other units' spray heads is documented in the monitoring and trending section below. The examination is component specific. Therefore, the applicant's scoping attribute is acceptable to the staff.

[Preventive Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or mitigate aging degradation. Since the pressurizer spray head examination is a one-time inspection program, and does not rely on actions to prevent the occurrence of aging effects or to mitigate the degree of aging that can occur, the staff concludes that the applicant's preventive action attribute is acceptable.

[Parameters Monitored or Inspected] The applicant stated that the parameter inspected by the pressurizer spray head examination is cracking of the pressurizer spray head. In Section 3.1.2.2.7 of NUREG-1800, the staff states, in part, that crack initiation and growth due to SCC and PWSCC are applicable effects for pressurizer spray heads. The applicant's parameters monitored or inspected program attribute for the McGuire/Catawba pressurizer spray heads is acceptable because it is a one-time inspection program designed to detect cracking that could result from SCC or PWSCC.

[Detection of Aging Effects] The applicant stated that the Pressurizer Spray Head Examination is a one-time inspection and will detect the presence of cracking in the pressurizer spray heads. The pressurizer spray head examination is a one-time inspection designed to detect potential cracks in the spray heads prior to their growing to a size greater than the critical crack size, which is a limiting allowable crack size for the material. This accounts for changes (reductions) in the critical crack size resulting from a loss of fracture toughness induced by thermal aging.

In Section 3.1.2.2.7 of NUREG-1800, the staff recommends that a plant-specific aging management program be proposed to manage crack initiation and unacceptable crack growth in pressurizer spray heads because existing programs may not be capable of mitigating or detecting crack initiation and growth due to SCC. The applicant's detection of aging effects attribute for the McGuire/Catawba pressurizer spray heads is a one-time inspection program designed to meet this recommendation, and is therefore acceptable to the staff.

[Monitoring and Trending] The applicant stated that the Pressurizer Spray Head Examination is a visual examination (VT-3) of the pressurizer spray head, and that no actions are taken as part of this program to trend inspection or test results. The applicant stated that, for McGuire 1, this new inspection will be completed following issuance of a renewed operating license for McGuire 1 and by June 12, 2021, and that any inspection (if needed, based on the results of the McGuire 1 spray head examination) of the McGuire 2 pressurizer spray head will be completed by March 3, 2023. The applicant stated that, for Catawba, if warranted based on the results of the McGuire 1 examination, the new inspections will be completed following the issuance of the renewed operating licenses for Catawba 1 and 2 and by December 6, 2024, for Catawba 1, and February 24, 2026, for Catawba 2. The program is designed to perform a one-time visual inspection of the McGuire 1 pressurizer spray head to ensure that cracks will be detected prior to reaching the critical crack size for the CASS materials used to fabricate the spray heads. The applicant will evaluate the results of pressurizer spray head examination performed at McGuire 1 and will use them as the basis for determining whether additional pressurizer spray head examinations are warranted for McGuire 2 and Catawba 1 and 2. The applicant evaluated whether the CASS materials in the pressurizer spray heads are susceptible to thermal aging and applied the methods in the staff's Interim Safety Guidance on CASS[3] as an acceptable

[3] Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,"* Project No. 690, dated

basis for concluding that loss of fracture toughness was not an applicable aging effect for the McGuire and Catawba pressurizer spray heads. Since the McGuire and Catawba pressurizer spray heads are not susceptible to thermal aging, the CASS materials used to fabricated the spray heads are considered to be tough, fracture-resistant materials, and any cracking in the pressurizer spray head is therefore considered to be a slow-acting mechanism. Therefore, the staff expects minimal cracking, if any, in the spray heads. Based on these considerations, the staff concludes use of a one-time inspection of the pressurizer spray head at McGuire 1 will be acceptable for detecting cracking in the spray heads for the other three units prior to their failure, and for determining whether additional inspections of the pressurizer spray heads at McGuire 2 and at Catawba 1 and 2 are warranted. However, the staff's position is that VT-3 examinations may not be capable of detecting cracks that could occur in the pressurizer spray head. Therefore, the staff requested that the applicant amend the Pressurizer Spray Head Examination to state that VT-1 examination methods, which are capable of detecting and resolving cracks in the pressurizer spray heads, will be used for the one-time inspection. This issue was characterized as SER open item 3.1.2.2.2-1. The scope of open item 3.1.2.2.2-1 included the potential need to revise the acceptance criteria element and the FSAR supplement.

In its response to open item 3.1.2.2.2.-1, dated October 28, 2002, the applicant stated that the visual inspection method for the pressurizer spray head examination will be revised to VT-1 examination methods, and that the acceptance criteria were in accordance with those specified for VT-1 examinations in Section XI of the ASME Boiler and Pressure Vessel Code. The applicant also stated that these changes will be reflected in a revision of the FSAR supplement. The applicant's response reflects that the applicant will implement a visual examination method for the pressurizer spray head examination that is capable of detecting surface cracks in the spray head material, and that any cracks detected by the examination will be evaluated using established Section XI acceptance criteria. This meets the criteria in Section XI of the ASME Code for performing visual examinations of Code Class components for cracking and, therefore, resolves the issue raised in open item 3.1.2.2.2-1. The staff considers open item 3.1.2.2.2-1 to be closed.

[Acceptance Criteria] The applicant stated that the acceptance criterion for the pressurizer spray head examination will be in accordance with those for ASME Section XI, VT-3 examinations. Surface-breaking cracks detected by these visual examinations are required by 10 CFR 50.55a, "Code and Standards," to be evaluated against corresponding flaw evaluation criteria that are provided in an acceptable edition of Section XI, ASME Boiler and Pressure Vessel Code, as endorsed by the rule. The applicant will assess any cracks detected by the examination against the flaw evaluation criteria for surface-breaking flaws in the 1989 Edition of Section XI to the ASME Boiler and Pressure Vessel Code. This is an acceptable edition of Section XI endorsed by reference in 10 CFR 50.55a. The staff identified open item 3.1.2.2.2-1 pertaining to the applicant's proposed use of VT-3 rather than VT-1 examination technique. Therefore, the applicant should apply VT-1 examination acceptance criteria from an accepted edition of the ASME Section XI code to evaluate any surface-breaking flaws that might be detected as a result of the VT-1 examination.

May 2000.

[Operating Experience] The applicant stated that the Pressurizer Spray Head Examination is a newly proposed, one-time inspection for the McGuire and Catawba pressurizer spray heads, and that there is not any operating experience that is pertinent to the evaluation of the McGuire and Catawba pressurizer spray heads at this time. This is acceptable since the results from examination of the pressurizer spray head at McGuire 1 will provide the LRA-specific experience that will be used to determine whether additional examinations are warranted for the pressurizer spray heads at McGuire 2 and Catawba 1 and 2.

FSAR Supplement: The Pressurizer Spray Head Examination is a new aging management program proposed by the applicant to manage the aging effects in the CASS spray heads for the McGuire and Catawba pressurizers. The Pressurizer Spray Head Examination was not originally described in Chapter 18 of the FSAR supplements for the McGuire and Catawba Nuclear Stations. By letter dated April 15, 2002, in response to RAI 2.3.2.7-1, the applicant amended the application and provided its FSAR supplement description for the Pressurizer Spray Head Examination. The applicant's FSAR supplement description for this examination was identical to the applicant's program attributes for the examination, as provided in the response to the RAI. Therefore, revision of the FSAR supplement was warranted to reflect resolution of open item 3.1.2.2.2-1. The scope of open item 3.1.2.2.2-1 included the potential need to revise the FSAR supplement.

In its response to open item 3.1.2.2.2-1, dated October 28, 2002, the applicant stated that the FSAR supplements for McGuire and Catawba will be revised to VT-1 visual inspection and acceptance criteria, which will be in accordance with the ASME Section XI code. Therefore, the staff finds this aspect of SER open item 3.1.2.2.2-1 resolved.

In conclusion, the applicant has proposed in its response to RAI 2.3.2.7-1 to implement a one-time inspection program, the Pressurizer Spray Head Examination, for the McGuire and Catawba pressurizer spray heads. Based on the staff's evaluation of the program attributes for the Pressurizer Spray Head Examination, as described in the applicant's response to RAI 2.3.2.7-1 and evaluated in the paragraphs above, and with the resolution of open item 3.1.2.2.2-1, the staff concludes that the Pressurizer Spray Head Examination for the McGuire and Catawba pressurizers will be sufficient to detect cracking of the spray head prior to failure of the components, and to maintain the pressure control function of the spray heads during the periods of extended operation for the units.

On the basis of its review, and with the resolution of open item 3.1.2.2.2-1, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed by the Pressurizer Spray Head Examination so that there is reasonable assurance that the intended function(s) of the pressurizer sub-components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the applicant's April 15, 2002, responses to RAIs 2.3.2.7-1, 3.1.2-1, 3.1.2-2, 3.1.2-3, and B.3.1-1. On the basis of its review, and with the resolution of open item 3.1.2.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the pressurizer sub-components will be adequately managed so that there is reasonable assurance that these sub-components will perform their intended functions consistent with the CLB for the

McGuire and Catawba reactor units throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

The four reactor vessels (RVs) at McGuire and Catawba are cylindrical shells with welded hemispherical lower heads and flanged, gasketed hemispherical upper heads. Each vessel contains the core, core supporting structures, control rods, and parts directly associated with the core. The upper head contains 82 penetrations (78 for control rod drive mechanism (CRDM) penetrations and 4 auxiliary head adapters). Each vessel has an inlet nozzle and an outlet nozzle for each of the four primary piping loops located just below the flange. Coolant enters through the inlet nozzles, flows down the core barrel-vessel wall annulus, turns at the bottom, and flows through the core to the outlet nozzles.

The bottom head has 58 penetrations for connection and entry of in-core instrumentation. Each penetration consists of a tubular member made from Inconel, which is attached to the lower head by a partial penetration weld. Stainless steel conduits extend from the Inconel tubes down through the concrete shield area and up to a thimble seal table. The retractable thimble tubes, which travel within the conduit, are closed at the leading end, are dry inside, and serve as the pressure barrier between the reactor water pressure and the reactor building atmosphere. Mechanical seals between the thimbles and the conduits are provided at the seal table.

The reactor vessel is classified as Safety Class 1; therefore, the design and fabrication of the vessel was carried out in accordance with ASME Code, Section III, Class 1 requirements. The use of sensitized stainless steel as a pressure boundary material was eliminated by either a choice of material or by programming the method of assembly. The carbon/low-alloy steel vessels are clad on their internal surfaces with austenitic stainless steel to prevent the carbon/low-alloy steel materials from being in direct contact with primary coolant.

For Catawba 1 and McGuire 2, the cylindrical portions of the RVs and the beltline nozzles are made from forgings; for McGuire 1 and Catawba 2, the cylindrical portions of the RVs and the beltline nozzles are made up of several shells, each consisting of formed plates joined by full penetration, longitudinal, and circumferential weld seams. The hemispherical heads are made from dished plates. The vessel plates or forgings are joined by welding, using the single or multiple wire submerged arc and the shielded metal arc processes.

Section 2.3.1.4 of the LRA, UFSAR Section 5.4 for McGuire, and UFSAR Section 5.3 for Catawba describe the reactor vessel and its appurtenances.

3.1.3.1 Technical Information in the Application

The applicant described its AMR of the RV and CRDM pressure boundary components for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's April 15, 2002, response to the RAI. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging for the RV and CRDM pressure boundary components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Nineteen component types are listed in Table 3.1-1 of the LRA. They include shell components, nozzles, and several vessel penetration components, including the CRDM housings and instrumentation tubes and their sub-components. Seventeen of these components provide the pressure boundary function. The core support pads provide the support function for the RV internals, and the RV integral attachments provide the component support to the RV.

3.1.3.1.1 Aging Effects

Table 3.1-1 includes the materials of construction of the components, the service environment that they are exposed to, the aging effects that act on the components, and the AMPs that will be used to manage the aging effects during the period of extended operation. The service environment listed in the table for the RV and CRDM pressure boundary components is borated water. The environment for the RV integral attachments, the RV head closure studs, and the external surfaces of the RV is the reactor building atmosphere. The table lists the following aging effects that require management during the period of extended operation:

- cracking
- loss of material
- reduction of fracture toughness
- loss of preload

3.1.3.1.2 Aging Management Programs

The applicant identified existing programs for managing the aging effects for the RV and CRDM pressure boundary components during the license renewal term. The following existing AMPs are identified in the application:

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Integrity Program
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program
- RCS Operational Leakage Monitoring Program
- Bottom-Mounted Instrumentation Thimble Tube Inspection Program

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the RV and CRDM pressure boundary components will be maintained consistent with the CLB under all design loading conditions throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to RV and CRDM pressure boundary components. However, Section 4.0 of the LRA includes the following TLAAs applicable to RV and CRDM pressure boundary components:

- reactor vessel neutron embrittlement (Section 4.2 of the application)
- metal fatigue for ASME Class 1 components (Section 4.3 of the application)

The staff's evaluations of the reactor vessel neutron embrittlement and ASME Class-1 metal fatigue TLAAs are documented in Sections 4.2 and 4.3 of this SER.

3.1.3.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.1.1 and 3.1.2, and in Table 3.1-1, of the LRA, and pertinent sections of Appendices A and B to the LRA, regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function(s) of the RV and CRDM pressure boundary components will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The reactor vessel closure region (i.e., flanged upper head) is sealed by two hollow metallic O-rings. Seal leakage is detected by means of two leak-off communications — one between the inner and outer ring and one outside the outer O-ring. These leak-off lines are within the scope of license renewal and are addressed as one of the non-Class 1 RCS components within the scope of LRA Table 3.3-41, "Aging Management Review Results - Reactor Coolant System (Non Class-1 Components)." The staff's evaluation of the applicant's AMRs for the RCS leak-off lines is documented in Section 3.3.32 of this SER.

3.1.3.2.1 Aging Effects

In accordance with Section 3.1 of the LRA, the applicant has performed a review of industry experience and NRC generic communications relative to the RV and CRDM pressure boundary components to provide reasonable assurance that the aging effects that require management for specific material-environment combinations are the only aging effects of concern for the Catawba and McGuire RV and CRDM components. This also included the plant-specific operating experience at both subject plants.

The effects of aging associated with RV and CRDM pressure boundary components requiring aging management are:

- loss of material and cracking for internal surfaces of alloy steel, stainless steel, and nickel-based alloy RV/CRDM components exposed to borated water conditions
- reduction of fracture toughness for the alloy steel base-metal and weld materials in the intermediate and lower shells of the McGuire and Catawba RVs
- loss of material from the external surfaces of carbon or alloy steel RV components that are exposed to the reactor building environment and could potentially be exposed to borated water leakage
- loss of material, cracking, and loss of preload as applicable aging effects for the RV closure studs, nuts, and washers
- loss of material and cracking for external surfaces of carbon and alloy steel integral attachments to the RV that are exposed to the reactor building environment

Loss of material and cracking are caused by aggressive service environments, including corrosive species, low pH, and elevated temperatures. To mitigate these effects, reactor water coolant chemistry and pH are strictly controlled within prescribed limits during plant operation and shutdown. The RV and CRDM pressure boundary components may be subject to loss of material and cracking under certain conditions.

Loss of material may occur in the RV and CRDM pressure boundary components under certain conditions. Carbon steel and low-alloy steel components may be susceptible to general-corrosion-induced loss of material under wet or damp conditions. Industry experience also demonstrates that potential borated water leakage from the RCS pressure boundary may corrode away and lead to a loss of material in carbon or low-alloy steel RCS pressure boundary components. NUREG/CR-5576 provides a summary of boric acid wastage events that had occurred in primary alloy or carbon steel pressure boundary components of domestic PWRs through 1990. The applicant has identified that loss material is an applicable effect for the exterior surfaces of carbon or low-alloy steel RV components that could be subjected to potential borated water leakage. Therefore, the following carbon or low-alloy steel RV components may be susceptible to loss of material: (1) RV steel shells, flanges, rings, bottom heads, and upper closure heads, (2) high-strength alloy steel bolting materials, and (3) alloy steel integral attachments (supports). The interior surfaces of the carbon steel/alloy steel portions of the McGuire and Catawba RV shells and heads are not exposed to the borated water/steam environment (i.e., they are clad with austenitic stainless steel to prevent exposure to the coolant) and therefore are not subject to boric-acid-induced loss of material in this manner.

Loss of material may also occur in stainless steel or nickel-based alloy components if the components are exposed to wet creviced conditions or if the components are subject to wear. Loss of material may occur in the RV thimble tubes and CRDM housing flange bolting materials as a result of wear. The applicant has appropriately identified loss of material as being applicable to stainless steel and nickel-based alloy RV components that may be exposed to borated water under creviced conditions (i.e., RV clad components or CRDM/RV head nozzles/housings), or are subject to wear (i.e., in the RV thimble tubes or CRDM housing flange bolting). The applicant has also conservatively listed loss of material as an applicable aging effect for the RV inlet and outlet nozzle safe-ends at McGuire and Catawba. The applicant's identification of loss of material as an applicable effect for the McGuire and Catawba RV components is acceptable because it conservatively accounts for the potential for the RV components made from carbon steel/alloy steel, stainless steel, or nickel-based alloys to lose material either by boric acid corrosion, crevice corrosion, or wear.

The potential for cracking to occur in carbon or low-alloy steel RV materials is predominantly a phenomenon of thermal fatigue. Fatigue is caused by large cyclic changes in stress as a result of pressure and thermal transients during service. PWSCC may initiate in RV and CRDM pressure boundary materials fabricated from nickel-based alloys or austenitic stainless steels as a result of exposure to the primary coolant in conjunction with the presence of stresses. RV underclad cracking may be an issue for cladding joined to RV forgings fabricated from SA 508, Class 2 steels (i.e., cracking in the forgings directly adjacent to the stainless steel cladding), if the forgings were fabricated to a coarse grain practice and clad by high-heat-input submerged arc processes. The applicant did not consider this to be an applicable aging mechanism that could lead to cracking of the forging materials used to fabricate the McGuire 2 and Catawba 1 RVs since Duke construction-vintage programs for controlling the welding of stainless steel cladding to low-alloy steel components were consistent with guidelines of NRC Regulatory Guides 1.43 and 1.44. The applicant did, however, identify cracking as a potential applicable effect for low-alloy steel RV shells, RV heads, and RV integral attachment supports based on other aging mechanism considerations, as well as for the austenitic stainless steel RV cladding and nickel-based alloy CRDM nozzle and housing components that are exposed to borated water conditions. The applicant's identification of cracking as an applicable effect for these components is acceptable because it accounts for the potential for these components to crack either as a result of thermal fatigue or by stress corrosion cracking.

Reduction in fracture toughness is also of concern during the period of extended operation for some RV/CRDM components. The alloy steel weld and base metals in the RV beltline are subject to reduction in fracture toughness as a result of neutron embrittlement. Reduction in fracture toughness may also occur in certain types of CASS components as a result of prolonged exposure to service temperatures above 250 °C (482 °F) (i.e., as a result of thermal aging). The applicant has identified reduction in fracture toughness as an applicable effect for the RV beltline base metal and weld materials. The applicant addresses reduction of fracture toughness of the RV beltline materials in the TLAA for the RV materials, as given in Section 4.2 of the application. The staff's evaluation of the TLAA for the RV beltline materials is given in Section 4.2 of this SER.

The applicant also identified in Table 3.1-1 that the CRDM latch housing was fabricated from CASS; however, as stated in Section of 3.1.1 of the application, the applicant's CASS analysis did not identify that this component was susceptible to thermal aging because the component was centrifugally cast. Therefore, the applicant did not identify reduction in fracture toughness as an applicable effect for the CRDM latch housing. This is acceptable to the staff because it is in agreement with a staff position which states that reduction in fracture toughness is not an applicable effect for centrifugally cast CASS RCS components[4].

Inspection of bolted connections and components is part of the applicant's ISI program under ASME Section XI, Subsection IWB (Class 1) inspections. The ISI effort is based on the applicant's response to IE Bulletin 82-02, "Degradation of Threaded Fasteners in Reactor Coolant Pressure Boundary of PWR Plants," which addressed stress corrosion cracking of SA 4140 low-alloy, high-strength steel bolting materials. Table 3.1-1 of NUREG-1800 identifies that high-strength, low-alloy steel bolted connections may be degraded by three potential aging effects: (1) stress corrosion cracking, (2) potential loss of material as a result of general or boric acid leakage corrosion, and (3) loss of preload as a result of stress relaxation. The applicant has appropriately identified these effects for the RV bolts, studs, nuts and washers. This is acceptable to the staff because it is in agreement with the aging effects identified in Table 3.1-1 of NUREG-1800 for bolted connections of the RV and other RCS subsystems.

On the basis of the description of the internal and external environments, materials used, and the applicant's review of industry and plant-specific experience, the staff concludes that the applicant has identified all aging effects that are applicable for the RV and CRDM pressure boundary components.

3.1.3.2.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant lists the AMPs that will be used to manage the effects of aging in RV and CRDM pressure boundary components during the period of extended operation. They include:

---

[4] Letter from C. I. Grimes (NRC) to D. J. Walters (NEI), *License Renewal Issue No. 98-0030, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components,"* Project No. 690, dated May 2000.

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Integrity Program
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program
- RCS Operational Leakage Monitoring Program
- Bottom-Mounted Instrumentation Thimble Tube Inspection Program

In Table 3.1-1 of the LRA, the applicant lists all RV and CRDM pressure boundary components within the scope of the license renewal with their intended functions, material groups, and environment. Also, the table identifies the aging effects requiring management, and the plant-specific AMPs required to manage these aging effects, during the period of extended operation.

The Chemistry Control Program (Section B.3.6 of LRA Appendix B) provides water quality that is compatible with the materials of construction used for the McGuire and Catawba RV and CRDM components in order to minimize loss of material and cracking. This program is developed based on plant TS requirements and on EPRI guidelines, which reflect industry experience.

In Table 3.1-1 of the LRA, the applicant stated that cracking and loss of material associated with the thimble seal table would be managed solely by implementation of the Chemistry Control Program. By letter dated January 28, 2002, the staff requested, in RAI 3.1-3, the applicant to clarify how implementation of the Chemistry Control Program by itself would be sufficient to manage loss of material and cracking in the thimble seals. In its response dated April 15, 2002, the applicant stated that, in addition to the Chemistry Control Program, the thimble seals are visually inspected during startup from each outage to ensure that they are not leaking, and that the seals are disconnected every outage so that the flux thimbles may be retracted during refueling. The applicant stated that, prior to restart, the flux thimbles are reinserted and the high pressure seal is reinstalled, and that these connections are visually inspected for leakage during startup of the units. The applicant stated that this inspection is part of the ISI plan, ASME Section XI, Table IWB-2500, Examination Category B-P. In its response to RAI 3.1.3-1, the applicant also provided a revised AMR for the thimble seal table that credited the ISI plan as an additional program for managing cracking and loss of material in the thimble seals. The staff finds this to be acceptable because the applicant has proposed to use both a preventive/mitigative program and an inspection-based program as a means of managing aging effects in the thimble seals.

The staff has evaluated the Chemistry Control Program as a common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) was developed by the applicant in response to NRC Generic Letter 88-05. Inspections are performed to provide reasonable assurance that borated water leakage from the reactor coolant pressure boundary does not lead to undetected loss of material on the external surface of RC piping and associated components, specifically for those made out of carbon steel or low-alloy steel. The staff's evaluation of this AMP is documented in Section 3.0 of this SER. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components.

For the RV and CRDM components, the ISI Plan (Section B.3.20 of LRA Appendix B) manages the aging effects of loss of material, cracking, and gross loss of preload. The scope of the ISI plan for Class 1 components complies with the requirements of ASME Section XI, Subsections IWB. Depending on the examination category, the methods of inspections may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The examination methods required by Subsection IWB for implementation either directly inspect for loss of material and cracking in the Class 1 components and are capable of detecting the aging effects, or inspect for indications of reactor coolant leakage which, in the case of bolted connections, would be indicative of a loss of preload in the bolt. Management of reduction in fracture toughness for the RV intermediate shell and lower shell materials is addressed in the applicant's TLAAs for the RVs, as provided in Section 4.2 of the application. The staff evaluates these TLAAs in Section 4.2 of this SER. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the reactor vessel and CRDM pressure boundary. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Alloy 600 Aging Management Review is described in Section B.3.1 of LRA Appendix B. The applicant stated that it will implement this review to ensure that nickel-based alloy locations are adequately managed by the ISI Plan (Section B.3.20 of LRA Appendix B) or other pertinent aging management programs, such as the CRDM Nozzle and Other Vessel Head Penetration Program (Section B.3.9 of LRA Appendix B), the Reactor Vessel Internals Inspection Program (Section B.3.27 of LRA Appendix B), or the Steam Generator Surveillance Program (Section B.3.3.1 of LRA Appendix B). According to the LRA, this program is a review that utilizes industry and Duke operating experience to define the additional inspection work that needs to be carried out in support of these two AMPs. The inspection methods and frequency of inspection for the Alloy 600/690, 82/182, and 52/152 locations for the period of extended operation will be adjusted as needed, based on the review. The staff has evaluated this AMP and found it to be acceptable for managing the aging effects identified for RV and CRDM pressure boundary components. The staff's evaluation of this AMP is documented in Section 3.1.2.2.2 of this SER.

The applicant credited the CRDM Nozzle and Other Vessel Closure Penetration Inspection Program for managing cracking (specifically primary water stress corrosion cracking) of nickel-based RV head penetrations exposed to borated water environments to ensure that the pressure boundary function is maintained during the period of extended operation. This AMP is used in conjunction with the Fluid Leak Management Program and the RCS Operational Leakage Monitoring Program (Section B.3.25 of LRA Appendix B) to manage the effects of aging of RV head penetrations. The staff's review of this AMP is documented in the following pages of this SER section.

The applicant has credited the Reactor Vessel Integrity Program (Section B.3.26 of LRA Appendix B) for managing reduction in fracture toughness of RV beltline materials to assure that the pressure boundary intended function of the RV beltline is maintained for the period of extended operation. The program includes an evaluation of radiation damage based on the pre-irradiation and post-irradiation testing of Charpy-V-notch and tensile specimens. The applicant concludes that this AMP is capable of ensuring that RV degradation is identified and corrective actions are taken before allowable limits are exceeded. Neutron fluences used for the pressurized thermal shock (PTS), upper shelf energy, and pressure-temperature limit TLAAs are based on the latest RV surveillance capsule reports for the McGuire and Catawba units submitted to the staff as part of AMP B.3.26 of LRA Appendix B. The staff's review of this AMP is documented in the following pages of this SER section.

The Bottom-Mounted Instrumentation (BMI) Thimble Tube Inspection Program (Section B.3.5 of LRA Appendix B) is a condition monitoring program. In NRC Bulletin No. 88-09 and Information Notice No. 87-44, the staff identified flow-induced vibration as a cause for wear (i.e., thinning) of the thimble tubes, resulting in degradation of the RCS pressure boundary and potentially leading to non-insoluble leak of reactor coolant. The amount of vibration the thimble tubes experience is determined by plant-specific factors, such as the gap distance from the lower core plate to the fuel assembly instrument tube, the amount of clearance between the thimble tube and the guide or instrument tube, the axial component of the local fluid velocity, the thickness of the thimble tube, and the moment of inertia of the thimble tube. The staff concluded in the bulletin that the only effective method for determining thimble tube integrity is through plant-specific inspections and periodic monitoring. The program is designed to identify loss of material due to wear in the BMI thimble tubes prior to leakage. It uses eddy current techniques on all of the thimble tubes to estimate loss of material. The frequency of inspection is based on an analysis of data obtained using wear rate relationships developed in Westinghouse report WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," dated 1991. The staff's review of this AMP is documented in the following pages of this SER section.

The RCS Operational Leakage Monitoring Program is designed to provide an additional line of defense against aging effects that any result in leakage due to cracking and loss of mechanical closure integrity. Both McGuire and Catawba have continual RCS leakage limits and system surveillance requirements as described in their TS. In the scope of this AMP, the applicant stated that it also manages, in part, aging effects for Inconel penetrations through the RV head. The staff's evaluation of the common AMP is documented in the following pages of this SER section.

<u>CRDM Nozzle and Other Closure Penetration Inspection Program (VHP Nozzle Program)</u>

The applicant provides a description of the VHP Nozzle Program in Section B.3.9 of LRA Appendix B. The applicant states that the purpose of the VHP Nozzle Program is to manage cracking of nickel-based alloy reactor vessel head penetration (VHP) nozzles that are exposed to the borated water environment to assure that the pressure boundary function is maintained during the period of extended operation. The applicant also states that the Fluid Leak Management Program, which performs walkdowns looking for evidence of leakage, and the RCS operational leakage monitoring program, which monitors system leakage, are used in conjunction with the VHP Nozzle Program to manage aging of the reactor vessel head penetrations. This program is a condition monitoring program credited with managing PWSCC of high nickel alloy reactor vessel head penetrations and is a complementary program to the ISI Plan.

The applicant credited the McGuire/Catawba VHP Nozzle Program for managing aging effects in the McGuire/Catawba Alloy 600 VHPs. The staff evaluated the VHP Nozzle Program on the following seven program attributes for the program:

1. scope of program
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

The staff evaluates the other three program attributes for the VHP Nozzle Program (i.e., confirmatory actions, corrective actions, and administrative controls) as part of its review of the applicant's Quality Assurance Program. The staff's evaluation of the Quality Assurance Program is documented in Section 3.0.4 of this SER.

In accordance with the issues raised in Generic Letter (GL) 97-01 and NRC Bulletins 2001-001, 2002-01, and 2002-02, the staff considers that aging management of PWSCC in the McGuire/Catawba VHP nozzles is an emerging issue that needs to be resolved in coordination with ongoing industry efforts for the current license period. However, since the staff considers that the docketed information in the applicant's responses to RAI B.3.9-1, and to NRC Bulletins 2001-001, 2002-01, and 2002-02, provides the current updated CLB for the VHP Nozzle Program, the staff also evaluated the VHP Nozzle Program against this docketed information. The CLB for the applicant's VHP nozzles and the VHP Nozzle Program will be updated when the applicant submits its response to NRC Bulletin 2002-02 within 30 days of its issuance.

[Program Scope] The applicant stated that the scope of the VHP Nozzle Program includes the control rod drive mechanism nozzles and head vent penetrations of each reactor vessel. These penetrations include 78 Control Rod Drive Mechanism (CRDM) type penetrations and one head vent penetration. The four auxiliary head adapter penetrations on each head are visually inspected as part of the VHP Nozzle Program and volumetrically examined by the ISI Plan. The applicant's scoping attribute for this program is acceptable to the staff because it accounts for inspections of all Alloy 600 penetration nozzles that are used in the McGuire and Catawba RV head designs.

[Preventive Actions] The applicant stated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The applicant's Preventive Actions attribute for this program is acceptable to the staff because the program uses an inspection-based approach to monitor for aging in the VHP nozzles for the Catawba and McGuire units and does not rely on actions to prevent the initiation of aging effects or to mitigate the amount of aging that may occur.

[Parameters Monitored or Inspected] The applicant stated that the VHP Nozzle Program monitors cracking of nickel-based alloy nozzles with partial penetration welds in the reactor vessel closure head. The applicant's Parameters Monitored or Inspected attribute for this program is acceptable to the staff because industry experience indicates that PWSCC is an applicable aging effect in the Alloy 600 VHP nozzles of PWRs.

[Detection of Aging Effects] The applicant states that, in accordance with information provided in the Monitoring and Trending program attribute below, the VHP Nozzle Program will detect cracking of nickel-based alloy reactor vessel head penetrations prior to loss of component intended function. The staff's evaluation of the Detection of Aging Effects attribute is incorporated into the staff evaluation of the applicant's Monitoring and Trending attribute that follows.

[Monitoring and Trending] The applicant stated that the VHP Nozzle Program will inspect the control rod drive mechanism type penetrations, the head vent penetration, and the auxiliary head vent penetration. This program will consist of both visual and volumetric examinations. Visual inspections apply to all penetrations in the reactor vessel head. Visual inspections of all accessible CRDM type penetrations will be completed every refueling outage. During each 10-year ISI interval, insulation is removed and 100 percent visual inspection of the outside surface of the head will be performed. This inspection will include CRDM type penetrations, auxiliary head adapter penetrations, and the head vent. Volumetric inspections within this program apply to the CRDM type penetrations and the head vent penetration. The auxiliary head adapter penetrations are inspected volumetrically by the ISI Plan.

Currently, eddy current inspection is used for detection of cracking. A combination of eddy current, ultrasonic, and liquid penetrant will be used for sizing indications. These methods may be updated based on industry experience. The number of penetrations inspected will be based on both Duke-specific experience gained through inspections performed at Oconee. and through industry experience on similar Westinghouse plants shared through the Westinghouse Owner's Group Program. For McGuire, this new inspection will be completed following issuance of renewed operating licenses for McGuire Nuclear Station, and by June 12, 2021 (the end of the initial license of McGuire 1). For Catawba, this new inspection will be completed following issuance of renewed operating licenses for Catawba Nuclear Station, and by December 6, 2024 (the end of the initial license of Catawba 1). Due to length of time in operation, it is expected that Unit 1 results will provide a leading indicator for Unit 2 results at each station. The results of these inspections will form the basis for timing of future inspections. The timing of these inspections may change based on either Duke-specific or industry experience.

The current industry-wide program for monitoring cracking in Alloy 600 VHP nozzles is based on an integrated ranking and monitoring program for VHP nozzles developed by the industry in the late 1990s. This program is based on the industry's generic and plant-specific responses to GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations," which ranked the susceptibility of Alloy 600 VHPs to PWSCC based on probabilistic cracking models. Based on a conservative assessment, the applicant indicated that the VHP Nozzle Program, in part, would call for eddy current examinations of McGuire 1 and Catawba 1 VHP nozzles prior to June 12, 2021, and December 6, 2024, respectively. The applicant also indicated that a combination of eddy current testing, ultrasonic testing, and dye-penetrant testing would be used to size any recordable indications that result from the eddy current examinations used for detection purposes. The applicant has indicated that, due to length of time in operation, it is expected that Unit 1 results will provide a leading indicator for Unit 2 results at each station. The results of these inspections will form the basis for timing of future inspections. The timing of these inspections may change based on either Duke-specific or industry experience.

Between November 2000 and April 2001, reactor coolant pressure boundary (RCPB) leakage was identified from the VHP nozzles of four U.S. PWR-design light-water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These findings are significant in that the cracking was reported to initiate from the OD side of the nozzle, either in the associated J-groove welds or heat-affect-zones, and not from the inside surface of the nozzles as was assumed in the industry responses to NRC Generic Letter (GL)97-01. In regard to this experience, the degradation was severe enough to penetrate through the RCPB for the nozzles and represented the first report of circumferential cracking in U.S. VHP nozzles.

In response to the identified cracking, the NEI and the MRP submitted Topical Report TP-1001491, Part 2, "PWR Materials Reliability Program Interim Alloy 600 Safety Assessments for US PWR Plant (MRP-44)." This report included a revised susceptibility ranking model for PWR plants. This revised model placed the VHP nozzles for the McGuire and Catawba units within 120-145 EFPY of the time the same conditions were evident at the plant which identified the circumferential cracking in its CRDM nozzles. On August 3, 2001, the NRC issued NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Coolant Pressure Vessel Head Penetration Nozzles," to address the potential safety implication of these findings. The bulletin (ADAMS Accession No. ML012080284) emphasized the need to use effective examination techniques capable of detecting flaws in these nozzles, using an approach that was consistent with the relative susceptibility of the VHP nozzles, and recommended an inspection-based program for the U.S. PWR industry that was based on the revised susceptibility rankings provided in the MRP-44 report.

In RAI B.3.9-1, the staff informed the applicant that the program description for the VHP Nozzle Program, as described in Section B.3.9 of Appendix B the LRA, did not specify whether the applicant would continue to be a participant in the NEI program for managing PWSCC type aging in Alloy 600 VHP nozzles of U.S. PWR designed facilities, and whether the applicant would continue to use the program as a basis for evaluating the Alloy 600 VHPs in the McGuire and Catawba nuclear units during the proposed extended operating terms for the units. With respect to this program the staff asked the applicant to (1) discuss how the recent circumferential cracking discussed in NRC Bulletin 2001-01 would impact the aging management program for the McGuire and Catawba CRDM penetration nozzles and other vessel head penetration nozzles, and (2) discuss what additional activities the applicant would be participating in, if any, that will be implemented as part of this program.

In its response to RAI B.3.9.1, dated April 15, 2002, the applicant stated the following:

> ...the recent circumferential cracking issue discussed in Bulletin 2001-001 will not affect the... [VHP Nozzle Program] ... as proposed in the application. Since circumferential cracking was identified at Oconee Nuclear Station in November 2000, Duke has been aware of the concern prior to NRC issuance of Bulletin 2001-001. The Oconee experience was taken into account during development of the program described in Section B.3.9 of the application. As discussed under Monitoring and Trending in the program description, Duke has committed to base the number of penetrations inspected on Duke-specific experience gained through inspections performed at Oconee and through industry experience on similar Westinghouse plants shared through the Westinghouse Owners Group.

In March 2002, and since the issuance of RAI B.3.9-1, a bare surface examination of the Davis-Besse reactor vessel head has been completed. The licensee determined that a number of

CRDM nozzles for the unit had severely degraded and leaked as a result of PWSCC. In two of these leaking nozzles, boric acid residue buildup had been severe enough to induce wastage of the ferritic steel in the reactor vessel head adjacent to the penetration nozzles. The severity of the wastage in one of the nozzles was critical because the wastage had corroded away the adjacent ferritic material in the upper RV head completely down to the head's stainless steel cladding. To address the potential safety implication of these findings to the industry as a whole, the NRC issued NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002, and NRC Bulletin 2002-02, "Reactor Pressure Vessel Head Degradation and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002.[5]

Duke provided its response to Bulletin 2002-01 for the McGuire and Catawba units by letter dated April 1, 2002. In its responses to both Bulletins (2001-01 and 2002-01), the applicant indicated that the current program includes the following provisions: (1) inspection of the vessel head, including one-time visual examinations of the bare surfaces of the McGuire and Catawba upper vessel heads as recommended in Bulletin 2002-01, (2) enhancement or augmentation of inspections if leakage is detected in any of the McGuire or Catawba VHP nozzles, (3) repairs of leaking VHP nozzles either in compliance with the repair requirements of Section XI of the ASME Code or acceptable alternatives approved by the NRC, and (4) cleaning or removal of boric acid residues if they are detected on the RV heads of the McGuire and Catawba reactor units.

The information in the applicant's responses to RAI B.3.9-1, GL 97-01, and NRC Bulletins 2001-01, 2002-01, and 2002-02 indicates that the applicant is an active participant in the NEI program for monitoring and controlling PWSCC in VHP nozzles. The current program, as described and updated in the applicant's responses to Bulletins 2001-01, 2002-01, and 2002-02, indicates that the applicant has responded to the issues and action requests raised in the Bulletins.[4] The staff and nuclear power industry are pursuing resolution of the reactor vessel penetration nozzle cracking issue and the Davis Besse reactor vessel head wastage issue identified in October 2000. The staff is evaluating potential changes to the requirements governing inspections of Alloy 600 vessel head penetration (VHP) nozzles, PWR upper RV heads, and other RCS piping and components (specifically with respect to non-destructive examinations and the ability to detect cracking in the VHP nozzles and loss of material due to boric acid corrosion). These current operating issues raise questions about the capability of the VHP nozzles to perform their intended functions during the current license term. The Commission recognized that aging issues could arise during the license renewal review that raise questions about the capability of structures or components to perform their intended functions during the current term of operation, and provided for such issues in 10 CFR 54.30, which requires that such issues be addressed under the current license, rather than as part of the license renewal review. Therefore, these issues are beyond the scope of this license renewal review, pursuant to 10 CFR 54.30(b).

---

[5] The applicant will comply with the reporting requirements of the bulletin and submit its responses to NRC Bulletin 2002-02 within 30 days of the bulletin's date of issuance (August 9, 2002). When submitted, the applicant's responses to NRC Bulletin 2002-02 will update the CLB for the McGuire and Catawba VHP nozzles and the applicant's VHP Nozzle Program.

However, since these issues might not be resolved prior to issuance of the renewed operating licenses for the McGuire and Catawba units, the staff requested the applicant to commit to implementing any actions, as part of the VHP Nozzle Program, that are agreed upon between the NRC, NEI, MRP, and the nuclear power industry to monitor for, detect, evaluate, and correct cracking in the VHP nozzles of U.S. PWRs, specifically as the actions relate to ensuring the integrity of VHP nozzles in the McGuire and Catawba upper RV heads during the extended period of operation. This commitment will ensure that the applicant's VHP Nozzle Program (as described in the McGuire and Catawba UFSARs) will be capable of monitoring for, detecting, evaluating (see the discussion of evaluation criteria guidelines in the staff's evaluation of acceptance criteria below), and correcting cracking in the McGuire and Catawba VHP nozzles and associated upper RV heads before unacceptable degradation of the VHP nozzles or associated upper RV heads occurs. This issue was characterized as SER open item 3.1.3.2.2-2. Any updates to the VHP Nozzle Program that result from resolution of this issue should be reflected in the UFSARs for the McGuire and Catawba units.

By letter dated October 28, 2002, the applicant provided the following response to open item 3.1.3.2.2-2:

> In response to New Open Item 3.1.3.2.2-2, Duke incorporates by reference (pursuant to §54.17(e)) its response to NRC Bulletin 2002-02 dated September 6, 2002. The following regulatory commitments were made by Duke in response to this bulletin:
> (1) Catawba and McGuire Nuclear Stations will supplement their Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle inspection programs with non-visual NDE methods.
> (2) Plans will be submitted that more specifically address methods, scope, coverage, frequencies, qualification requirements, and acceptance criteria for future Catawba and McGuire inspections of the Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles within four years of the date of this response.
>
> In addition, the Alloy 600 Aging Management Review described in Appendix B.3.1 of the Application will be performed to ensure that nickel-based alloy locations are adequately inspected by the *Inservice Inspection Plan* (Appendix B.3.20) or other existing programs such as the Control Rod Drive Mechanism and Other Vessel Closure Penetration Program (Appendix B.3.9), the Reactor Vessel Internals Inspection (Appendix B.3.27), and the Steam Generator Surveillance Program (Appendix B.3.31). The review will demonstrate that the general oversight and management of cracking due to primary water stress corrosion cracking (PWSCC) is effective for the period of extended operation.
>
> The summary description of the Alloy 600 Aging Management Review contained in each station's FSAR supplement will be revised to add the following:
>
>> Consideration of industry operating experience is part of the Alloy 600 Aging Management Review. The NRC staff is currently reviewing industry experience with Alloy 600 locations as a result of the Davis-Besse event in March 2002. Any future regulatory actions that may be required as a result of this review will be provided by the staff in separate generic communications to all plants.
>>
>> The summary aging management program descriptions contained in this FSAR will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communication's that result from this event.

The summary description of the Control Rod Drive Mechanism and Other Vessel Closure Penetration Inspection Program contained in each station's FSAR supplement will be revised to add the following:

> This summary description will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communication's that result from the Davis-Besse event in March 2002.

The staff has reviewed the applicant's response to open item 3.1.3.2.2-2, which referenced Duke's responses to NRC Bulletins 2002-01 and 2002-02. CRDM nozzle cracking and RV head wastage issues documented in these NRC Bulletins are current operating issues that are being addressed for all PWR reactors and, therefore, involve matters that are not subject to a renewal review pursuant to 10 CFR 54.30. However, the applicant provided revised FSAR supplement summary descriptions of the VHP Nozzle Program and the Alloy 600 Review to indicate that these programs will be revised as necessary to reflect any new or revised commitments made by Duke in response to staff generic communications that result from the March 2002 Davis-Besse event. The commitment to incorporate resolution of this current operating issue into the VHP Nozzle Program and the Alloy 600 Review, as stated in the revised FSAR supplements, ensures that the methods implemented by the applicant for inspecting the McGuire and Catawba VHP nozzles and RV heads will be sufficient to detect PWSCC in the VHP nozzles. Therefore, the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the VHP Nozzle Program and the Alloy 600 Review will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff considers open item 3.1.3.2.2-2 closed. With respect to boric acid corrosion, the staff is continuing to gather information on industry programs to determine what, if any, regulatory action is needed.

[Acceptance Criteria] The applicant stated, for the visual inspection, any boron detected on the outer surface of the vessel head due to penetration leakage is unacceptable. The applicant stated, for the volumetric examination, axial flaws detected during volumetric inspection will be analyzed and accepted via the NUMARC acceptance criteria which was approved by the NRC in their SER dated November 19, 1993. The applicant stated that circumferential flaws will be analyzed and addressed on a case-by-case basis by the NRC. The applicant's responses to NRC Bulletins 2001-01 and 2002-01 update this to provide acceptance criteria for visual examinations performed on bare surfaces of the McGuire and Catawba RV heads. The applicant's responses to NRC Bulletins 2001-01 and 2002-01 state that the applicant considers any signs of boric acid residues on the surfaces of the reactor vessel heads to be indications of reactor coolant (borated water) leakage, and that indications of this nature will need additional evaluation and corrective action. However, the staff is currently resolving with the industry exactly what the requirements should be for inspections of VHP nozzles in U.S. PWRs, and the scope of any actions and/or activities agreed upon between the NRC and the industry for resolution of this issue will need to include exactly what the acceptance criteria will be for the VHP nozzle inspection techniques that are agreed on between the staff and the industry and what the corrective actions should be if cracking is detected. In the interim, the staff has issued flaw evaluation criteria guidelines that may be used as the flaw acceptance criteria for VHP nozzles.[6] This matter is addressed in open item 3.1.3.2.2-2.

[Operating Experience] The applicant stated that, on April 1, 1997, the NRC issued GL 97-01, "Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations." GL 97-01 indicated that the NRC did not object to individual licensees basing their inspection plans for vessel closure head penetrations on an integrated industry program. The applicant stated that McGuire and Catawba are participants in the WOG generic program to address GL 97-01, and that the industry's generic responses to GL 97-01 placed the VHP nozzles for domestic PWRs into three susceptibility groups based on the probability of having a 75 percent through wall crack. The applicant stated that the VHP nozzles for the McGuire and Catawba RV heads are in the greater than 15 EFPY grouping (would not expect a 75 percent through wall crack for more than 15 EFPY from January 1, 1997), which reflects the lowest susceptibility to cracking of the CRDM penetrations. The staff notes that this is based on the industry's GL 97-01 susceptibility rankings.

The applicant's responses to Bulletins 2001-001 and 2002-01 provide the applicant's updated susceptibility rankings for the McGuire and Catawba VHP nozzles and updated evaluations of how the VHP nozzle circumferential cracking event at the Oconee nuclear station and boric acid wastage event of the Davis-Besse RV head impact the applicant's proposed schedules and methods for monitoring PWSCC in the McGuire and Catawba VHP nozzles. The applicant's Operating Experience program attribute, as updated by the applicant's responses to NRC Bulletins 2001-01 and 2002-01, provides the applicant's review of pertinent VHP nozzle degradation events and reflects the applicant's most current CLB for resolving the issue of monitoring for PWSCC in the VHP nozzles of the McGuire and Catawba units. The staff anticipates that this will be updated to reflect the applicant's response to Bulletin 2002-02. This is acceptable since it meets the requirements of 10 CFR Part 54.

FSAR Supplement: The applicant's FSAR supplement for the VHP Nozzle Program is documented in Section 18.2.6, of Appendix A to the LRA and provides an overview of the program as described in Section B.3.9 of LRA Appendix B. In its SER with open items, the staff indicated that the applicant should modify the FSAR supplement descriptions of the VHP Nozzle Program to reflect the docketed information in the applicant's responses to RAI B.3.9-1 and to NRC Bulletins 2001-01 and 2002-01, as well as the information that will be provided in the applicant's response to NRC Bulletin 2002-02. The staff also stated that the applicant should modify its UFSARs for both McGuire and Catawba to reflect the resolution of the VHP nozzle integrity issue associated with open item 3.1.3.2.2-2 to the extent that such resolution impacts the AMP for license renewal. Since these items were addressed in its response to open item 3,1,3,2,2-2, and since a revised FSAR supplement was provided in this open item response, this issue is resolved.

In conclusion, the staff reviewed the information in Section B.3.9 of LRA Appendix B, the applicant's response to RAI B.3.9-1, and the information provided in the applicant's responses to the SER open item and NRC Bulletins 2001-0, 2002-01, and 2002-02. With the resolution of open item 3.1.3.2.2-2, the staff finds that the program will be an acceptable means of

[6] Letter from Jack R. Strosnider (NRC) to Alex Marion (NEI), "Flaw Evaluation Criteria," September 24, 2001.

monitoring and controlling age-related degradation in McGuire and Catawba VHP nozzles during the period of extended operation for each unit.

Reactor Vessel Integrity Program

The applicant describes its Reactor Vessel Integrity Program in Section B.3.26 of the LRA. This AMP is applicable to both McGuire and Catawba RVs. The applicant credits this program for managing the reduction in fracture toughness of RV beltline materials to assure that the pressure boundary of the beltline materials is maintained during the period of extended operation. In the program, the effects of irradiation will be determined by pre-irradiation and post-irradiation testing of Charpy V-notch and tensile samples.

The staff reviewed the applicant's description of the program and the program's attributes to determine whether the applicant had demonstrated that it will adequately manage the applicable effects of aging in RV beltline region materials during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The scope of this AMP is stated by the applicant to include all of the RV beltline materials, as defined in 10 CFR 50.61(a)(3). This program includes an evaluation of radiation damage based on pre-irradiation and post-irradiation samples periodically withdrawn from the RVs. The monitoring and trending within this AMP include fluence received by the specimens, effective full power years, cavity dosimetry, and monitoring of plant changes. Tables are included in the LRA to specify the RV irradiation capsule withdrawal schedules for McGuire and Catawba units.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Section B.3.26 of LRA Appendix B to determine if the Reactor Vessel Integrity Program will adequately manage the reduction in fracture toughness of the RV beltline material base metal and weld materials, so that the RV intended functions will be maintained consistent with the CLB throughout the period of extended operation for all four reactor vessels.

The staff evaluated the Reactor Vessel Integrity Program on the following seven program attributes:

1. program scope
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Reactor Vessel Integrity Program is documented in Section 3.0.4 of this SER.

[Scope of Program] The scope of the Reactor Vessel Integrity Program includes all beltline materials as defined in 10 CFR 50.61(a)(3). The scope of the test program for these materials involves the measurement of irradiation effects by pre-irradiation and post-irradiation testing of

Charpy V-notch and tensile samples. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

[Preventive Actions] According to the LRA, no actions are taken as part of this program to prevent aging effects or mitigate aging degradation of the RV. The Reactor Vessel Integrity Program is a surveillance monitoring program designed to monitor for materials property changes, specifically for loss of fracture toughness, in the materials used to fabricate the RVs for the McGuire and Catawba reactor units, and to comply with the reactor vessel material surveillance program capsule withdrawal and testing requirements of 10 CFR Part 50, Appendix H. The program uses Charpy-V impact testing of the surveillance capsule specimens as its method for monitoring changes (losses) in fracture toughness in the RV beltline materials. Surveillance programs implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, are not designed to prevent or mitigate aging effects before their occurrence. Therefore, the staff concludes the applicant's preventive actions attribute is acceptable because the program is not designed to be a preventive or mitigative type program for precluding aging effects prior to their occurrence.

[Parameters Monitored or Inspected] The applicant stated that this AMP monitors reduction of fracture toughness of beltline materials due to irradiation embrittlement. This is consistent with the scope of Reactor Vessel Integrity Program required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

[Detection of Aging Effects] The applicant stated that the effects of aging will be detected based on the data obtained in the monitoring and trending effort from the Reactor Vessel Integrity Program. This is consistent with the scope of RV material surveillance programs required to be implemented in accordance with the requirements of 10 CFR Part 50, Appendix H, and is therefore acceptable to the staff.

[Monitoring and Trending] Each of the Duke RVs has six specimen capsules located in guide baskets welded to the outside of the neutron shield pads directly opposite the center portion of the core. McGuire 1 and Catawba 2 capsules contain specimens that are oriented parallel and perpendicular to the principal rolling direction of the limiting shell plate in the core region. McGuire 2 and Catawba 1 specimens are oriented parallel and perpendicular to the principal forging direction of the limiting core region shell forging. Associated weld and heat-affected-zone specimens are also included in the capsules. From tests carried out according to industry approved industry standards, the effects of irradiation and the neutron fluence values for the RV beltline materials are estimated. The applicant stated that these data are used to analyze the upper shelf energy values and RT_{PTS} values used for the upper shelf energy and PTS structural integrity assessments for the reactor vessel beltline materials, and to generate pressure-temperature curves for the future operation of each RV (refer to TLAA Sections 4.2.1, 4.2.2, and 4.2.3 of the LRA).

The staff reviewed the surveillance capsule withdrawal schedules in Tables B.3.26-1 and B.3.26-2 of the LRA. In its review of these surveillance capsule withdrawal schedules, the staff determined that the withdrawal schedules for McGuire 1 and 2 and Catawba 1 and 2 were acceptable, with the exception being that the staff required further clarification of the applicant's withdrawal plans for McGuire 1 Capsule W and Catawba 2 Capsule U. This issue was characterized as SER open item 3.1.3.2.2-1. In open item 3.1.3.2.2-1, the staff requested further information regarding the applicant's plans for McGuire 1 Capsule W and Catawba 2 Capsule U. The staff's evaluation of the TLAAs for upper shelf energy, pressurized thermal shock, and the generation of pressure-temperature (P-T) limit curves is decumented in Sections 4.2.1, 4.2.2, and 4.2.3 of this SER, respectively.

In its response to open item 3.1.3.2.2-1, dated October 28, 2002, the applicant stated that the following surveillance capsules are in storage:

- McGuire 1: Capsule Z
- McGuire 2: Capsules Z and Y
- Catawba 1: Capsules U and X
- Catawba 2: Capsule Y

The applicant also indicated that the capsules are available for further testing if necessary.

The applicant stated that McGuire 1 Capsule W is a standby capsule and is being used to support the evaluation of material properties of the beltline RV weld material at a plant owned by a different licensee. The applicant stated that the weld material used in the fabrication of McGuire 1 Capsule W is not the limiting material for the McGuire 1 RV. The applicant also stated that Capsule W is not necessary to conform to the ASTM E-185 surveillance capsule withdrawal schedule that is required by 10 CFR Part 50, Appendix H, for McGuire 1. However, the applicant clarified that Capsule W will be removed from the RV and evaluated after the completion of cycle 18, which will cause it to have an accumulated fluence that is a little less than twice the projected fluence at the expiration of the extended period of operation.

The weld material used in the fabrication of the McGuire 1 surveillance capsules, including McGuire 1 Capsule W, is heat No. 20291/12008. This material is projected by the applicant's TLAA for PTS (refer to Section 4.2 of the LRA and the staff's assessment in Section 4.2 of this SER) to have a shift in reference temperature (ΔRT_{NDT} value) in the 100 to 200 °F range. Appendix H of 10 CFR Part 50 requires licensees to implement their RV surveillance programs in accordance with the withdrawal schedule and testing requirements of ASTM Standard Procedure E185. The ASTM E185 version of record for McGuire and Catawba is ASTM E185-82, which is an acceptable version of the standard invoked by 10 CFR Part 50, Appendix H. For a material with a projected ΔRT_{NDT} value in the 100 to 200 °F range, ASTM E185-82 requires a minimum of four capsules to be withdrawn and tested in accordance with the standard's testing methods. The final capsule is required to be removed and tested when the capsule has accumulated a neutron fluence that is between the projected fluence at the end of license (EOL) and twice the projected fluence at the EOL. For license renewal purposes, the end of license fluence is projected to occur at the expiration of the extended license (EOLE).

The revised withdrawal schedule for McGuire 1, as provided in the applicant's response to open item 3.13.2.2-1, indicates that the four surveillance capsules have already been removed and tested in accordance with ASTM E185-82. The revised withdrawal schedule indicates the third capsule (Capsule V) was removed at a fluence that is approximately equivalent to both the projected fluence for the vessel inner wall fluence at EOL and the 1/4T location at EOLE. The revised withdrawal schedule also indicates that the fourth capsule (Capsule Y) was removed at a fluence that is approximately equivalent to the projected fluence for the vessel inner wall fluence at EOLE. These capsules provide relevant data for the effect that neutron irradiation will have on the material properties for the McGuire 1 RV through the expiration of the extended period of operation. The revised withdrawal schedule in the applicant's response to open item 3.13.2.2-1 also indicates that a fifth McGuire 1 capsule, Capsule W, will be removed in April 2004 at an approximate fluence of 4.52 x 10^{19} n/cm^2, which is slightly less than twice the projected fluence for the RV at EOLE. If implemented, removal and testing of Capsule W will meet the withdrawal schedule criteria in ASTM E185-82 for a 5-capsule withdrawal program and will provide additional relevant information for the behavior of the McGuire 1 RV during the period of extended operation. This is conservative and acceptable since the applicant is only required to remove four McGuire 1 surveillance capsules for testing to meet ASTM E185-82. However, should the applicant choose to remove and test the specimens in McGuire 1 Capsule W for chemistry, fracture toughness, and fluence data, the applicant will report the data for NRC review, as required by 10 CFR Part 50, Appendix H, Section IV., and will apply the surveillance capsule data to the evaluations for PTS, as required by 10 CFR 50.61(c)(2) and (c)(3), and for USE and P-T limits, as required by 10 CFR Part 50, Appendix G, Section III. This closes open item 3.1.3.2.2-1 with respect to the staff's inquiries in regard to McGuire 1 surveillance Capsule W.

In its response to open item 3.1.3.2.2-1, the applicant also stated that Capsule U does not have to be removed and tested for the Catawba 2 RV surveillance program. The applicant stated that the projected shift in reference temperature (ΔRT_{NDT} value) at the end of the extended operating period is less than 100 °F and, therefore, only 3 capsules are required to be removed to meet the requirements of ASTM E185-82, as invoked by the requirements of 10 CFR Part 50, Appendix H. In spite of this, the applicant clarified that it is conservatively implementing a 5-capsule surveillance capsule withdrawal program for Catawba 2, even though the applicant is required by ASTM E185-82 to implement only a 3-capsule withdrawal program for the unit. The applicant provided a revised Note 2 in the withdrawal schedule for Catawba 2 in order to include this clarification in the proposed withdrawal schedule for Catawba 2 in the LRA.

The weld material used in the fabrication of the Catawba 2 surveillance capsules, including Catawba 2 Capsule 2, is heat No. 83648. This heat was also used to fabricate the circumferential and axial beltline welds in the Catawba 2 vessel. This material is projected by the applicant's TLAA for PTS (refer to Section 4.2 of the LRA and the staff's assessment in Section 4.2 of this SER) to have a ΔRT_{NDT} value that is less than 100 °F. For a material with a projected ΔRT_{NDT} value less than 100 °F, ASTM E185-82 requires a minimum of three capsules to be withdrawn and tested in accordance with the standard's testing methods. For a 3-capsule withdrawal schedule, the standard requires that the final capsule be removed and tested when the capsule has accumulated a neutron fluence that is approximately the projected fluence for the RV at the expiration of operation license. For license renewal purposes, this is when the capsule has accumulated a neutron fluence that is approximately the projected fluence at EOLE.

The revised withdrawal schedule for Catawba 2, as provided in the applicant's response to open item 3.13.2.2-1, indicates that the three surveillance capsules have already been removed and tested in accordance with ASTM E185-82. The revised withdrawal schedule indicates the second capsule (Capsule X) was removed at a fluence that is approximately equivalent to the both the projected fluence for the vessel inner wall fluence at EOL and the 1/4T location at EOLE. The revised withdrawal schedule also indicates that the third capsule (Capsule W) was removed at a fluence that is approximately equivalent to the projected fluence for the vessel inner wall fluence at EOLE. These capsules provide relevant data for the effect that neutron irradiation will have on the material properties for the Catawba 2 RV through the expiration of the extended period of operation. The applicant has stated that Capsule U is an optional surveillance capsule that may be removed and tested at the applicant's discretion. Based on the projected fluences for the Catawba 2 RV welds fabricated from heat No. 83648, the staff concurs that Capsule U is an optional capsule for a 3-capsule surveillance withdrawal program. However, should the applicant choose to remove and test the specimens in Catawba 2 Capsule U for chemistry, fracture toughness, and fluence data, the applicant will be required under the requirements of 10 CFR Part 50, Appendix H, Section IV, to report the data for NRC review, and to apply the surveillance capsule data to the evaluations for PTS, as required by 10 CFR 50.61(c)(2) and (c)(3), and for USE and P-T limits, as required by 10 CFR Part 50, Appendix G, Section III. This closes open item 3.1.3.2.2-1 with respect to the staff's inquiries in regard to Catawba 2 surveillance Capsule U.

[Acceptance Criteria] The applicant listed the acceptance criteria as follows:

- Charpy specimens must be removed from the surveillance capsules and tested to ensure that the upper shelf energy is greater than 50 ft-lb.
- Calculations of the reference temperature for pressurized thermal shock, RT_{PTS}, must be below the screening criteria of 270°F for plates, forgings, and longitudinal welds, and below 300°F for circumferential welds.
- Acceptable pressure-temperature curves must be maintained approved and current in the plant TS.
- Capsules included in the reactor vessel integrity program must be withdrawn on a schedule.

These acceptance criteria are consistent with the requirements for protection of the reactor vessels against pressurized thermal shock (PTS) events, as specified in 10 CFR 50.61, the requirements for upper shelf energy and P-T limits, as specified in 10 CFR Part 50, Appendix G, the requirements of 10 CFR 50.36 for incorporating the P-T limits for the reactor vessels and RCS into the plant TS, and the requirements for implementation of reactor vessel materials surveillance programs, as specified in 10 CFR Part 50, Appendix H. The staff therefore concludes that the acceptance criteria program attribute for Reactor Vessel Integrity Program is acceptable.

[Operating Experience] By letter dated January 28, 2002, the staff issued four RAIs (B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4) relative to the fast neutron exposure of the McGuire and Catawba reactor pressure vessel beltline materials. Each RAI asked the following questions:

1. Why does the magnitude of the end-of-license fast neutron fluence projection at the pressure vessel inner diameter change as each surveillance capsule is withdrawn and analyzed?
2. Why does the location of the projected maximum exposure of the pressure vessel change as each surveillance capsule is withdrawn and analyzed?

The staff reviewed the LRA and the applicant's responses to B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4, dated April 15, 2002, in order to evaluate the acceptability of the fluence methodology and fluence values to be used for application to the P-T curves and the calculation of the RT_{PTS} for all four units. The applicant submitted four surveillance capsule reports to address the staff's RAIs on neutron fluence:

1. WCAP-15117, "Analysis of Capsule V and the Dosimeters from Capsules U and X from the Duke Power Company Catawba 1 Reactor Vessel Surveillance Program" by E. Terek et. al., Westinghouse Energy Systems, October 1998.
2. WCAP-15243, "Analysis of Capsule V and the Capsule Y Dosimeters from the Duke Energy Catawba 2 Reactor Vessel Radiation Surveillance Program" by T. Laubham, et. al., Westinghouse Electric Company, LLC, September 1999.
3. WCAP-15253, "Duke Power Company Reactor Cavity Neutron Measurement Program for William B. McGuire 1 Cycle 12" by J. Perock et. al., Westinghouse Electric Company, LLC, July 1999.
4. WCAP-15334, "Duke Power Company Reactor Cavity Neutron Measurement Program for William B. McGuire 2 Cycle 12" by A. Fero, Westinghouse Electric Company, LLC, November 1999.

The staff determined that the four surveillance capsule reports use a fluence computational methodology that adheres to the guidance of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U.S. Nuclear Regulatory Commission, March 2001. This document provides the staff's bases for evaluating methodologies for neutron fluence dosimetry measurements and for calculating neutron fluence values used in reactor vessel structural integrity determinations. Since the applicant is using a computational neutron fluence methodology that meets the staff's recommended methods in RG 1.190, the staff finds that the applicant's methodology for calculating the neutron fluence values for the reactor vessel structural integrity TLAAs (specifically TLAAs 4.2.1, 4.2.2, and 4.2.3), and the resulting calculated neutron fluence values for the TLAAs, is acceptable. The staff's evaluation of the TLAAs for upper shelf energy, pressurized thermal shock, and the generation of P-T limit curves is documented in Sections 4.2.1, 4.2.2, and 4.2.3 of this SER, respectively.

The staff notes that the assumed effective full power years (EFPY) of operation to the end of the extended license is 54 EFPY for the Catawba Units and 51 EFPY for the McGuire Units. The projected neutron fluence values for these EFPY are conservative for RV neutron fluence.

FSAR Supplement: The staff reviewed Appendix A - FSAR supplement (McGuire Section 18.2.21 and Catawba Section 18.2.20) of the LRA and found that the description of the Reactor Vessel Integrity Program is consistent with Section B.3.26 of LRA Appendix B.

In conclusion, on the basis of its review of the Reactor Vessel Integrity Program, and with the resolution of SER open item 3.1.3.2.2-1 pertaining to the applicant's use of reactor vessel capsules, the staff finds that the continued implementation of this AMP provides reasonable assurance that the reduction in fracture toughness of RV beltline region materials will be adequately managed, such that the intended function(s) of the RV will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

Bottom-Mounted Instrumentation (BMI) Thimble Tube Inspection Program

The applicant described its BMI Thimble Tube Inspection Program in Section B.3.5 of LRA Appendix B. The applicant credits the BMI Thimble Tube Inspection Program for managing aging effects in the thimble tubes of the McGuire and Catawba reactor units, specifically loss of material due to wear in the BMI thimble tubes prior to leakage.

The staff reviewed this section of the application to determine whether the applicant has demonstrated that the aging effects of the BMI thimble tubes will be adequately managed by this program during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant indicated that the thimble tubes are part of the reactor coolant pressure boundary and that the bottom-mounted instrumentation Thimble Tube Inspection Program is a condition monitoring program. The program utilizes eddy current testing (ECT) to determine thimble tube wall thickness and predict wear rates for early identification of the need for corrective action before the potential thimble tube failure. The applicant also indicated that the BMI Thimble Tube Inspection Program was created and implemented in both plants in response to NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." To date the applicant has performed six inspections at Catawba (three inspections per unit) and four inspections at McGuire (two inspections per unit).

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that intended function will be maintained consistent with the CLB throughout the period of extended operation for the BMI thimble tubes.

The staff evaluated the BMI Thimble Tube Inspection Program on the following seven attributes for the program:

1. program scope
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

The staff's evaluations of these program attributes are given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the BMI Thimble Tube Inspection Program is documented in Section 3.0.4 of this SER.

[Program Scope] The applicant indicated that the scope of the BMI Thimble Tube Inspection Program includes all thimble tubes installed in each reactor vessel. This is acceptable to the staff because the program includes all thimble tubes within its scope for each reactor vessel.

[Preventive Actions] No actions are taken as part of this program to prevent aging effects or mitigate aging degradation. The staff agrees with this assessment because this program is an inspection-based detection program and does not include preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the BMI Thimble Tube Inspection Program monitors tube wall degradation of the BMI thimble tubes. The staff agrees with the applicant because failure of the thimble tubes would result in a breach of the reactor coolant pressure boundary. The staff also agrees with the applicant in that monitoring of the tube wall degradation of the BMI thimble tubes will ensure the tube structural integrity.

[Detection of Aging Effects] The applicant stated that, as provided in the Monitoring and Trending section below, the BMI Thimble Tube Inspection Program will detect loss of material due to wear prior to component loss of intended function. The staff agrees with this assessment because the BMI Thimble Tube Inspection Program includes the use of eddy current testing and ensures that all of the thimble tubes are inspected. The use of eddy current testing will detect tube wear or tube degradation, and thus prevent tube failure that will result in a breach of reactor coolant pressure boundary. Therefore, the staff finds this approach acceptable.

[Monitoring and Trending] The applicant stated that inspection of the BMI thimble tubes is performed using eddy current testing (ECT). All of the thimble tubes are inspected. The frequency of examination is based on an analysis of the data obtained using wear rate relationships that are predicted based on Westinghouse research presented in WCAP-12866, "Bottom-Mounted Instrumentation Flux Thimble Wear." These wear rates, as well as the results of the eddy current examinations, are documented in site-specific calculations. The ECT results are trended and inspections are planned prior to the refueling outage in which thimble tube wear is predicted to exceed the Acceptance Criteria specified below. The staff finds the monitoring and trending aspects of the BMI Thimble Tube Inspection Program acceptable because the tube inspections are planned based on site-specific calculations. This will ensure that the thimble tubes continue to perform their intended function.

[Acceptance Criteria] The applicant indicated that the acceptance criteria for the BMI thimble tubes is 80 percent through wall (thimble tube wall thickness is not less than 20 percent of initial wall thickness). This acceptance criteria was developed by Westinghouse in WCAP 12866, "Bottom-Mounted Instrumentation Flux Thimble Wear," and reported to the NRC by Duke. The NRC staff finds the 80 percent through wall acceptance criteria to be acceptable because the remaining 20 percent will provide adequate structural integrity until the tube is capped or replaced. Also, the maximum number of thimble tubes that can be capped on a unit is 14, and a minimum of 75 percent, or 44 of 58 total tubes, are required to be in service in order to perform core power distribution surveillance.

[Operating Experience] On July 26,1988, the NRC issued IE Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors." The NRC requested that inspection programs be implemented that included the following:

- The establishment, with technical justification, of an appropriate thimble tube wear acceptance criterion (e.g., percent through wall loss). This acceptance criterion should include allowances for such items as inspection methodology and wear scar geometry uncertainties.
- The establishment, with technical justification, of an appropriate inspection frequency (e.g., every refueling outage).
- The establishment of an inspection methodology that is capable of adequately detecting wear of the thimble tubes (e.g., eddy current testing).

The applicant has implemented a program at McGuire and Catawba that meets these criteria based on a proprietary study performed for the Westinghouse Owner's Group.

Duke indicated that, since IE Bulletin 88-09 was issued, three inspections have been performed on Catawba 1 and three on Catawba 2 thimble tubes. The inspections on Unit 1 were performed during End Of Cycle (EOC) 1EOC-3 (1988), 1EOC-7 (1993), and 1EOC-11 (1999). The Inspections on Unit 2 were performed during 2EOC-2 (1989), 2EOC-3 (1990), 2EOC-5 (1993), and 2EOC-7 (1998). The inspections did not detect significant changes in wear rates for either unit. Currently, no tubes are capped on Unit 1, and two tubes are capped on Unit 2 due to wear. Wear projections performed in the referenced calculations have determined that further eddy current testing will not be required for Units 1 and 2 until 1EOC-7 (2008) and 2EOC-13 (2004), respectively, barring significant changes in cycle length or reactor geometry.

Similar inspections have been performed on McGuire 1 and 2. Unit 1 has been inspected twice, during 1EOC-5 (1988) and 1EOC- 14 (2001), with 10 tubes showing detectable wall loss. Two additional tubes were capped due to other types of damage. Unit 2 was inspected during 2EOC-5 (1989) and 2EOC-8 (1993), with eight tubes showing wear. Future inspections are currently planned to occur at 1EOC-19 (2008) for Unit 1 and 2EOC-16 (2005) for Unit 2. The staff finds that the McGuire and Catawba operating experience confirms that the BMI Thimble Tube Inspection Program is effective in detecting tube wear and tube degradation.

FSAR Supplement: In LRA Appendix A-1 (McGuire) and LRA Appendix A-2 (Catawba), the applicant provided new FSAR sections describing the BMI Thimble Tube Inspection Program. The information provided in the FSAR supplement is consistent with the program described in Appendix B, and no changes are required.

In conclusion, the staff has reviewed the BMI Thimble Tube Inspection Program, as described in Section 3.3.5 of LRA Appendix B. On the basis of its review, the staff finds that the applicant has demonstrated that this AMP will adequately manage aging effects identified for the reactor vessel thimble tubes, such that there is reasonable assurance that their intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reactor Coolant System Operational Leakage Monitoring Program

In Section B.3.25 of LRA Appendix B, the applicant described the Reactor Coolant System Operational Leakage Monitoring Program. The purpose of the Reactor Coolant System Operational Leakage Monitoring Program is to provide an additional line of defense against aging effects that may result in leakage due to cracking and loss of mechanical closure integrity. McGuire and Catawba have continual reactor coolant system TS leakage limits and system surveillance requirements, as defined in their technical specifications. The Reactor Coolant Operational Leakage Monitoring Program Is a condition monitoring program that provides reasonable assurance that leakage will be detected prior to loss of reactor coolant system function.

The staff reviewed the LRA to determine whether the applicant has demonstrated that this program will adequately manage the applicable effects of aging during the period of extended operation. It was noted that this program is not a new aging management program, but is an ongoing requirement of the technical specifications for the McGuire and Catawba units, as required by 10 CFR 54.21(a)(3).

The staff evaluated the Reactor Coolant System Operational Leakage Monitoring Program on the following seven attributes for the program:

1. program scope
2. preventive actions
3. parameters monitored or inspected
4. detection of aging effects
5. monitoring and trending
6. acceptance criteria
7. operating experience

The staff's evaluation of these program attributes is given in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Reactor Coolant System Operational Leakage Monitoring Program is documented in Section 3.0.4 of this SER.

[Program Scope] The applicant described the scope of the reactor coolant operational leakage monitoring program as all reactor coolant components that contain coolant; however, it is specifically credited with managing aging of bolted closures on the steam generators, pressurizer, and reactor coolant pumps, as well as the Inconel penetrations on the reactor vessel head and steam generator tubes. The staff noted that the applicant relies on a combination of the Reactor Coolant System Operational Leakage Monitoring Program, the Chemistry Control Program, and the ISI Program to manage cracking and loss of mechanical integrity of the subject components. The staff reviewed the scope of the program and concluded that because it is comprehensive, in that it includes those components that may affect the integrity of the reactor coolant system, the scope is appropriate to determine, in part, the effects of aging on those items within the program scope.

[Preventive or Mitigative Actions] The applicant indicated that no actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff considers the monitoring program to be designed to identify leakage and allow corrective action to be taken prior to loss of component function. Therefore, the staff agrees that there is not a need for preventive actions.

[Parameters Monitored or Inspected] The applicant stated that the Reactor Coolant System Operational Leakage Monitoring Program monitors reactor coolant system operational leakage and steam generator primary to secondary leakage. Because the program is required by plant TS, and is capable of identifying leakage at low levels, the staff finds the monitoring to be appropriate for the stated purpose of the program.

[Detection of Aging Effects] The applicant stated that the Reactor Coolant System Operational Leakage Monitoring Program is capable of detecting cracking of the reactor coolant system pressure boundary and loss of mechanical closure integrity of bolted closures in cases where leakage is occurring. Because the monitoring system is required by the plant TS, and the system is continuously monitored, the staff concludes that it is capable of detecting aging effects.

[Monitoring and Trending] The applicant stated in the LRA that the method for monitoring reactor coolant system operational leakage is specified in McGuire and Catawba Technical Specifications 3.4.13, RCS Operational Leakage, and 3.4.15, RCS Leakage Detection Instrumentation.

The NRC's regulations, in General Design Criterion (GDC) 30 of Appendix A to 10 CFR 50, require a means to detect and, to the extent practical, to identify the location of the source of reactor coolant system leakage. Regulatory Guide 1.45 describes methods acceptable to the NRC staff for selecting leakage detection systems. The primary method used by the applicant to detect leakage into the containment is measurement of the containment floor and equipment drain sump level. The sump level rate of change is calculated by the plant computer and can detect a 1 gallon per minute (gpm) leak within an hour. Leakage from the reactor coolant, main steam, and feedwater systems can be detected in this way. The containment ventilation unit condensate drain tank level change is another method used by the applicant to detect leakage. This system is also capable of detecting a 1 gpm leak. Radioactivity monitoring of particulate and gaseous radiation levels is also indicative of reactor coolant system leakage because of the activity levels contained within the reactor coolant system during operation of the plant. Primary to secondary leakage from steam generator tubes is detected by effluent monitoring (for activity) within the secondary steam and feedwater systems.

The applicant performs a reactor coolant water inventory balance every 72 hours at steady state operation, as specified in plant technical specifications, to verify that leakage is within allowable limits. Steam generator primary to secondary leakage is monitored continuously using an operator aid computer point, radiation monitors, condensate steam air ejector off gas, or secondary tritium samples, depending on monitoring equipment availability and operating mode.

Because the monitoring program meets NRC requirements as noted above, and is capable of identifying leaks as small as 1 gpm, the staff finds that the monitoring activity is acceptable for this program.

[Acceptance Criteria] The acceptance criteria for Reactor Coolant System Operational Leakage Monitoring Program are found in the plant TS (Limiting Condition for Operability 3.4.13, RCS Operational Leakage). Because the TS have been reviewed and approved by the staff, the staff finds this to be acceptable.

[Operating Experience] The applicant performed a search of licensee event reports (LERs) to demonstrate the effectiveness of the Reactor Coolant System Operational Leakage Monitoring Program for McGuire and Catawba. Many of the LERs were maintenance issues; however, several identified what the applicant considered to be age-related events. Some of these events included leakage due to loose valve bonnet bolts, leakage from an incore thermocouple fitting, a leaking compression fitting, and a weld failure due to fatigue resulting from cavitation. In all of the above cases, a determination was made that the events had no significance regarding the health and safety of the public.

The applicant noted that another use of this program, especially prior to steam generator replacement, is monitoring of primary to secondary leakage through the steam generators. Leakage that is still within allowable limits can be monitored, and a determination regarding timing of shutdown and repair of steam generator tubes can be made.

FSAR Supplement: Because the Reactor Coolant System Operational Leakage Monitoring Program is not a new program and currently is described in the McGuire and Catawba Technical Specifications, the staff finds that there is not a need to include the program description in the FSAR.

In conclusion, the staff finds that the Reactor Coolant System Operational Leakage Monitoring Program has been demonstrated to be capable of providing an additional line of defense against aging effects that may result in leakage due to cracking and loss of mechanical closure integrity. Based on the staff's review, the continued implementation of the Reactor Coolant System Operational Leakage Monitoring Program provides reasonable assurance that the aging effects will be managed, and that the reactor coolant pressure boundary will continue to perform its intended function for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.3 Conclusions

The staff reviewed the information included in Section 3.1.1 of the LRA, as supplemented by the April 15, 2002, response to the RAI. On the basis of its review, and with the resolution of open item 3.1.3.2.2-1 pertaining to the Reactor Vessel Integrity Program and open item 3.1.3.2.2-2 pertaining to the VHP Nozzle Program, the staff concludes that the applicant has demonstrated that the aging effects associated with the RV and CRDM pressure boundary components will be adequately managed, so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4 Reactor Vessel Internals

The reactor vessel (RV) internals consist of the lower core support structure, the upper core support structure, and the in-core instrumentation support structure. The lower core support structure consists of the core barrel, the core baffle, the lower core plate and support columns, the neutron shield pads, and the core support, which is welded to the core barrel. The lower core support structure is supported at its upper flange from a ledge in the reactor vessel, and its lower end is restrained from transverse motion by a radial support system attached to the vessel wall. The upper core support structure, which is removed as a unit during refueling, consists of the upper support assembly and the upper core plate, between which are contained the upper head injection (UHI) support columns and guide tube assemblies. The upper core support assembly is positioned in its proper orientation with respect to the lower support structure by slots in the upper core plate which engage the upper core plate alignment pins. The in-core instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom.

The RV internals support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and control rod drive mechanisms, direct coolant flow past the fuel elements, direct coolant flow to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the in-core instrumentation.

As described in Section 4.2.2 of McGuire UFSAR and Section 3.9.5 of Catawba UFSAR, the design and operating characteristics of the RV internals for McGuire and Catawba are identical, with the following exceptions. For McGuire, the UHI upper internals assembly originally provided passage for the UHI accumulator water from the vessel head plenum directly to the top of the fuel assemblies during a postulated LOCA. The UHI accumulator has been removed from service by capping the injection piping at the top of the vessel head. The UHI internals were not modified. For Catawba, the UHI upper internals assembly provide passage for the core cooling water from the vessel head plenum directly to the top of the fuel assemblies during a postulated LOCA.

3.1.4.1 Technical Information in the Application

The applicant described its AMR of the RV internals for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the applicant's responses to RAIs 3.1.4-1 through 3.1.4-4 and RAIs B.3.27-1 and B.3.27-2, all dated April 15, 2002. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging for the RV internals will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

RV internals are fabricated from stainless steel, with the exception of the irradiation specimen holder spring and the lower core support structure clevis inserts and fasteners, which are fabricated from a nickel-based alloy. Table 3.1-1 of the LRA, identifies a small number of the stainless steel RV internals made from CASS. These are the upper support column, including the base, conduit support, and thermocouple stop (U1); the 15x15 and 17x17 guide tube assembly; the UHI flow columns (base); and the BMI (upper end, cruciform).

The RV internals are immersed in borated reactor coolant water at a normal operating temperature of approximately 315 °C (600 °F). In the core region, they are also exposed to high neutron fluence.

3.1.4.1.1 Aging Effects

In Table 3.1-1 of the LRA, the applicant identifies that the following aging effects are generally applicable to the RV internals requiring AMRs:

- cracking
- loss of material
- loss of preload
- reduction in fracture toughness
- dimensional changes