NUREG-1772

# Safety Evaluation Report
Related to the License Renewal of McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2

Docket Nos. 50-369, 50-370, 50-413, and 50-414

Duke Energy Corporation

**U.S. Nuclear Regulatory Commission**
**Office of Nuclear Reactor Regulation**
**Washington, DC 20555-0001**

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**Division of Regulatory Improvement Programs**
**Office of Nuclear Reactor Regulation**
**U.S. Nuclear Regulatory Commission**
**Washington, DC 20555-0001**

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January 2003

**ABSTRACT**

This safety evaluation report documents the Nuclear Regulatory Commission's (NRC's) review of Duke Energy Corporation's (Duke's) application to renew the operating licenses for McGuire Nuclear Station, Units 1 and 2 (McGuire 1 and 2), and Catawba Nuclear Station, Units 1 and 2 (Catawba 1 and 2). The NRC's Office of Nuclear Reactor Regulation has reviewed the McGuire 1 and 2 and Catawba 1 and 2 license renewal application for compliance with the requirements of Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

On June 13, 2001, Duke submitted applications for renewal of McGuire 1 and 2 Operating License Nos. NPF-9 and NPF-17, which were issued pursuant to Section 103 of the Atomic Energy Act of 1954, as amended, for a period of up to 20 years beyond the current license expiration dates of June 12, 2021, and March 3, 2023, for McGuire 1 and 2, respectively. The McGuire nuclear facility is located 17 miles north-northwest of Charlotte, North Carolina, in Mecklenburg County. McGuire 1 and 2 are four-loop, Westinghouse pressurized-water reactors with nuclear steam supply systems designed to generate 3411 megawatts thermal, or 1129 megawatts electric.

In the same submittal of June 13, 2001, Duke requested renewal of the Catawba 1 and 2 Operating License Nos. NPF-35 and NPF-52, which were issued under Section 103 of the Atomic Energy Act of 1954, as amended, for a period of up to 19 years beyond the current license expiration dates of December 6, 2024, and February 24, 2026, respectively. The Catawba nuclear facility is located 18 miles southwest of Charlotte, North Carolina, in York County. Catawba 1 and 2 are four-loop, Westinghouse pressurized-water reactors with nuclear steam supply systems designed to generate 3411 megawatts thermal, or 1129 megawatts electric.

The NRC McGuire and Catawba license renewal project manager is Rani Franovich. Ms. Franovich may be reached at 301-415-1868. Written correspondence should be addressed to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

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ABBREVIATIONS

| | |
|---|---|
| ACI | American Concrete Institute |
| ACRS | Advisory Committee on Reactor Safeguards |
| ACSR | aluminum conductor steel reinforced |
| AFW | auxiliary feedwater (system) |
| AMP | aging management program |
| AMR | aging management review |
| ANSI | American National Standards Institute |
| AS | auxiliary steam (system) |
| ASME | American Society of Mechanical Engineers |
| ASTM | American Society for Testing and Materials |
| BMI | bottom-mounted instrumentation |
| BTP | Branch Technical Position |
| BWI | Babcock and Wilcox International |
| CASS | cast austenitic stainless steel |
| CCW | condenser circulating water (system) |
| CFR | Code of Federal Regulations |
| CIV | containment isolation valve |
| CLB | current licensing basis |
| CRDM | control rod drive mechanism |
| CSS | containment spray system |
| CUF | cumulative usage factor |
| CVCS | chemical and volume control system |
| DBA | design basis accident |
| DBD | design basis document |
| ECCS | emergency core cooling systems |
| ECT | eddy current test |
| EFPY | effective full-power years |
| ELL | Electrical Licensing Library |
| EOC | end of cycle |
| EOLE | end of life extended |
| EPDM | ethylene propylene dienyl monomer |
| EPL | vital batteries system |
| EPQ | diesel generator batteries system |
| EPRI | Electric Power Research Institute |
| EQ | environmental qualification |
| EQD | standby shutdown facility diesel batteries system |
| ETM | standby shutdown facility batteries system |
| FAC | flow-accelerated corrosion |
| FD | (system) flow diagram |
| FI | filtration |
| FP | fire protection |
| FSAR | final safety analysis report |
| GALL | Generic Aging Lessons Learned (Report) |
| GDC | general design criterion or general design criteria |
| GEIS | generic environmental impact statement |

| | |
|---|---|
| gpm | gallons per minute |
| GSI | generic safety issue |
| HAZ | heat-affected zone |
| HELB | high-energy line break |
| HVAC | heating, ventilation, and air conditioning |
| HT | heat transfer |
| I&C | instrumentation and controls |
| IASCC | irradiation-assisted stress corrosion cracking |
| ID | inner diameter |
| IGSCC | intergranular stress corrosion cracking |
| IPA | integrated plant assessment |
| IR | insulation resistance |
| ISG | interim staff guidance |
| ISI | inservice inspection |
| ITS | Improved Technical Specifications |
| LBB | leak-before-break (analysis) |
| LEFM | linear elastic fracture mechanics |
| LER | Licensee Event Report |
| LOCA | loss-of-coolant accident |
| LRA | license renewal application |
| LWR | light-water reactor |
| MeV | million electron volts |
| MIC | microbiologically induced corrosion |
| Mpa | mega pascals |
| MRP | Materials Reliability Project |
| MW | megawatts |
| NC | reactor coolant |
| NDT | nil ductility temperature, non-destructive testing |
| NEI | Nuclear Energy Institute |
| NEPA | National Environmental Policy Act |
| NFPA | National Fire Protection Association |
| NPAR | nuclear plant aging research |
| NRC | Nuclear Regulatory Commission |
| NSAC | Nuclear Safety Analysis Center |
| NSD | Nuclear System Directive |
| NSSS | nuclear steam supply system |
| NSW | nuclear service water (system) |
| NW | containment valve injection water (system) |
| ODSCC | outside diameter stress corrosion cracking |
| OSHA | Occupational Safety and Health Administration |
| P-T | pressure-temperature |
| P&ID | piping and instrumentation diagram |
| PB | pressure boundary |
| PCB | power circuit breaker |
| PIP | Problem Investigation Process |
| PORV | power-operated relief valve |
| ppb | parts per billion |
| ppm | parts per million |

| | |
|---|---|
| psig | pounds per square inch gauge |
| PTS | pressurized thermal shock |
| PWHT | post-weld heat treated |
| PWR | pressurized water reactor |
| PWSCC | primary water stress corrosion cracking |
| RAI | request for additional information |
| RCCA | rod cluster control assembly |
| RCP | reactor coolant pump |
| RCS | reactor coolant system |
| RF | interior fire water (system) |
| RG | regulatory guide |
| RHR | residual heat removal (system) |
| RPV | reactor pressure vessel |
| RTD | resistance temperature detector |
| RSG | replacement steam generator |
| RT | reference temperature |
| RV | reactor vessel |
| RVI | reactor vessel internals |
| RVID | Reactor Vessel Integrity Database |
| RWST | refueling water storage tank |
| SBO | station blackout (event) |
| SCC | stress corrosion cracking |
| SCs | structures and components |
| SER | safety evaluation report |
| SFP | spent fuel pool |
| SG | steam generator |
| SIS | safety injection system |
| SLC | Selected Licensee Commitments |
| SNSW | standby nuclear service water |
| SNSWP | standby nuclear service water pond |
| SR | surveillance requirement |
| SRP | Standard Review Plan |
| SCC | stress corrosion cracking |
| SCV | steel containment vessel |
| SE | safety evaluation |
| SER | safety evaluation report |
| SOC | Statement of Considerations |
| SSs | systems and structures |
| SSCs | systems, structures, and components |
| SSE | safe-shutdown earthquake |
| SSF | standby shutdown facility |
| SSS | standby shutdown system |
| TFMP | Thermal Fatigue Management Program |
| TGSCC | transgranular stress corrosion cracking |
| TH | throttle |
| TLAA | time-limited aging analysis |
| TR | testing requirement |
| TS | technical specification(s) |

| | |
|---|---|
| TSSR | technical specification surveillance requirement |
| UFSAR | updated final safety analysis report |
| UHI | upper head injection |
| UT | ultrasonic testing |
| VA | auxiliary building ventilation (system) |
| VC | control area ventilation (system) |
| VCP | Vessel Closure Penetration (Nozzle Inspection Program) |
| VD | diesel building ventilation (system) |
| VE | annulus ventilation (system) |
| VF | fuel handling building ventilation (system) |
| VHP | vessel head penetration |
| VK | miscellaneous structures ventilation (system) |
| VT | visual examination |
| W | Westinghouse |
| WCAP | Westinghouse topical report |
| WOG | Westinghouse Owners Group |
| YC | control area chilled water (system) |

# 1. INTRODUCTION AND GENERAL DISCUSSION

## 1.1 Introduction

This document is a safety evaluation report (SER) on the application to renew the operating licenses for McGuire Nuclear Station, Units 1 and 2 (McGuire or McGuire 1 and 2), and Catawba Nuclear Station, Units 1 and 2 (Catawba or Catawba 1 and 2), filed by Duke Energy Corporation (Duke or the applicant). Throughout this SER, "McGuire" or "Catawba" refers to both units (Unit 1 and Unit 2). When the staff discusses information specific to a particular unit, it will refer to that unit as McGuire 1, McGuire 2, Catawba 1, or Catawba 2.

By letter dated June 13, 2001, Duke submitted its application to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the McGuire and Catawba units' operating licenses for up to an additional 20 years. The application was received by the NRC on June 14, 2001. The NRC staff reviewed the McGuire and Catawba license renewal application (LRA) for compliance with the requirements of Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings. The project manager for the McGuire and Catawba safety review is Rani Franovich. Ms. Franovich may be contacted by telephone at (301) 415-1868 or by electronic mail at rlf2@nrc.gov. Alternatively, written correspondence can be sent to the following address:

License Renewal and Environmental Impacts Program
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: Rani Franovich, Mail Stop O-12D3

In its LRA, the applicant requested renewal of the operating licenses issued under Section 103 of the Atomic Energy Act of 1954, as amended, for McGuire 1 and 2 (License Nos. NPF-9 and NPF-17) and Catawba 1 and 2 (License Nos. NPF-35 and NPF-52). For McGuire 1, Duke requested a period of 20 years beyond the current license expiration date of June 12, 2021.

The current operating licenses for McGuire 2, Catawba 1, and Catawba 2 expire on March 3, 2023, December 6, 2024, and February 24, 2024, respectively. Duke had requested, by letters dated June 22, 1999, an exemption from 10 CFR 54.17(c), which prohibits an applicant for renewal from submitting its application earlier than 20 years before the expiration of its current operating license. By letters dated October 1, 2001, the NRC staff issued exemptions from this requirement for McGuire 2 and Catawba 1 and 2 with the safety evaluation reports enclosed. Therefore, in its license renewal application, Duke requested a period of 40 years from the date of the issuance of the renewed licenses for McGuire 2 and Catawba 1 and 2, which is less than 20 years beyond the current license expiration dates for these units.

In Section 1.5 of its LRA and in the June 13, 2002, transmittal letter, Duke Energy Corporation made the following request:

> As reflected in these proposed revisions to the license expiration dates, Duke recognizes the legal limits associated with the term of renewed operating licenses. We also note that the technical and environmental reviews performed in connection with this Application cover operation for a period of sixty years. Duke therefore requests that the NRC complete its safety and environmental reviews

> such that 60-years of operation are evaluated even though the renewed licenses issued may actually provide somewhat less than an additional 20-years of operation beyond the end of the current operating licenses of one or more of the McGuire or Catawba units.

To accommodate this request, the staff focused its attention on the time-limited aging analyses (TLAAs) provided in Chapter 4 of the LRA and identified the following sections of the LRA that described TLAAs that assumed 60 years of plant operation:

- Section 4.2, "Reactor Vessel Neutron Embrittlement"
- Section 4.3.2, "ASME Section III, Class 2 and 3 Piping Fatigue"
- Section 4.7.1, "Reactor Coolant Pump Flywheel Fatigue"

Other Chapter 4 sections of the LRA identify aging effects that will be managed by an aging management program, in accordance with 10 CFR 54.21(c)(iii), or identify aging that is not applicable to either McGuire or Catawba. The staff reviewed the three LRA Sections and associated TLAAs listed above and concluded that they remain valid for 60 years of operation. Therefore, they remain valid for the period of extended operation in accordance with 10 CFR 54.21(c).

The McGuire plant is located in northwestern Mecklenburg County, North Carolina, 17 miles north-northwest of Charlotte, North Carolina. Both McGuire units consist of Westinghouse pressurized water reactors with nuclear steam supply systems designed to operate at core power levels up to 3411 megawatts thermal, or approximately 1129 megawatts electric. Details concerning the plant and the site are found in the updated final safety analysis report (UFSAR) for McGuire.

The Catawba plant is located in the north central portion of South Carolina, in northeastern York County, approximately 18 miles southwest of Charlotte, North Carolina. Both Catawba units consist of Westinghouse pressurized water reactors with nuclear steam supply systems designed to operate at core power levels up to 3411 megawatts thermal, or approximately 1129 megawatts electric. Details concerning the plant and the site are found in the UFSAR for Catawba.

The license renewal process proceeds along two tracks: (1) a technical review of safety issues and, (2) an environmental review. The requirements for these two reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review is based on Duke's LRA and on the applicant's answers to requests for additional information (RAIs) from the NRC staff. In meetings and docketed correspondence, Duke has also supplemented its answers to the RAIs. The public can review the LRA and all pertinent information and material, including the UFSAR, at the NRC Public Document Room, 11555 Rockville Pike, Rockville, MD 20852-2738. In addition, the McGuire and Catawba LRA and significant information and material related to the license renewal review are available on the NRC web page at www.nrc.gov.

This SER summarizes the findings of the staff's safety review of the McGuire and Catawba LRA and describes the technical details considered in evaluating the safety aspects of the proposed operation of the plants for up to an additional 20 years beyond the term of the current operating licenses. The staff reviewed the LRA in accordance with NRC regulations and the guidance presented in the NRC "Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants," which was issued as NUREG-1800 in July 2001.

Chapters 2 through 4 of the SER document the staff's review and evaluation of license renewal issues that have been considered during the review of the LRA. Chapter 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). Appendix A is a chronology of the NRC's and the applicant's principal correspondence related to the review of the LRA. Appendix B is a bibliography of the documents used during the review. The NRC staff's principal reviewers for this project are listed in Appendix C. Appendix D contains a list of commitments provided by the applicant in a letter dated December 16, 2002, and confirmed by the staff.

In accordance with 10 CFR Part 51, the staff prepared draft plant-specific supplements to the generic environmental impact statement (GEIS). The supplements discuss the environmental considerations related to renewing the licenses for McGuire and Catawba. The draft plant-specific supplements to the GEIS were issued separately from this report. Specifically, NUREG-1437, Supplement 8, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding McGuire Nuclear Station, Units 1 and 2," issued May 2002, is the draft environmental impact statement for McGuire. Similarly, NUREG-1437, Supplement 9, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Catawba Nuclear Station, Units 1 and 2," issued May 2002, is the draft environmental impact statement for McGuire.

## 1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, licenses for commercial power reactors to operate are issued for up to 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations, not technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC anticipated interest in license renewal and held a workshop on nuclear power plant aging. That led the NRC to establish a comprehensive program plan for nuclear plant aging research (NPAR). On the basis of the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not involve technical issues that would preclude extending the life of nuclear power plants.

In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to life extension for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54. The NRC participated in an industry-sponsored demonstration program to apply the rule to pilot plants and develop experience to establish implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly for the implementation of the maintenance rule, which also manages plant aging phenomena.

As a result, in 1995 the NRC amended the license renewal rule. The amended 10 CFR Part 54 established a regulatory process that is expected to be simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR Part 54 was clarified to focus on managing the adverse effects of aging rather than on identifying all aging mechanisms. The rule changes were intended to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort to amend 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal and to fulfill, in part, the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

### 1.2.1 Safety Reviews

License renewal requirements for power reactors are based on two principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provides and maintains an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain SSCs during the period of extended operation and a few other safety issues.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles, the rule (in 10 CFR 54.4) defines the scope of license renewal as including those plant SSCs (1) that are safety-related, (2) whose failure could affect safety-related functions, and (3) that are relied on to demonstrate compliance with the Commission's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout.

Pursuant to 10 CFR 54.21(a), the applicant must review all SSCs that are within the scope of the rule to identify SCs that are subject to an aging management review (AMR). SCs that are subject to an AMR are those that perform an intended function without moving parts, or without a change in configuration or properties, and that are not subject to replacement based on a qualified life or specified time period. As required by 10 CFR 54.21(a), the applicant must demonstrate that the effects of aging will be managed in such a way that the intended function or functions of the SCs that are within the scope of license renewal will be maintained, consistent with the current licensing basis (CLB), for the period of extended operation.

Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental effects of aging that may affect active equipment are more readily detectable and will be identified and corrected through routine surveillance, performance monitoring, and maintenance activities. The surveillance and maintenance programs and activities for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required to continue throughout the period of extended operation.

Pursuant to 10 CFR 54.21(d), each LRA is required to include a supplement to the final safety analysis report (FSAR). This FSAR supplement must contain a summary description of the applicant's programs and activities for managing the effects of aging.

Another requirement for license renewal is the identification and updating of time-limited aging analyses (TLAAs). During the design phase for a plant, certain assumptions are made about the initial operating term of the plant, and these assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs will be adequately managed for the period of extended operation.

In July 2001, the NRC issued Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating License;" NUREG-1800, "Standard Review Plan for the Review of License Renewal Application for Nuclear Power Plants" (SRP-LR); and NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." These documents describe methods acceptable to the NRC staff for implementing the license renewal rule, and techniques used by the NRC staff in evaluating applications for license renewal. The draft versions of these documents were issued for public comment on August 31, 2000 (64 FR 53047). The staff assessment of public comments was issued in July 2001 as NUREG-1739, "Analysis of Public Comments on the Improved License Renewal Guidance Documents." The regulatory guide endorsed an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 3, issued in March 2001. The regulatory guide will be used along with the SRP to review this LRA and to assess topical reports on license renewal submitted by industry groups. As experience is gained, the NRC will improve the SRP and clarify the regulatory guidance.

### 1.2.2 Environmental Reviews

In December 1996, the staff revised the environmental protection regulations in 10 CFR Part 51 to facilitate environmental reviews for license renewal. The staff prepared a "Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants" (NUREG-1437) to document its evaluation of the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. Analyses of environmental impacts of license renewal that must be evaluated on a plant-specific basis are identified as Category 2 issues in 10 CFR Part 51, Subpart A, Appendix B. Such analyses must be included in an environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the NRC performs a plant-specific review of the environmental impacts of license renewal, including whether there is new and significant information not considered in the GEIS. Four public meetings were held, two near McGuire on September 25, 2001, and two near Catawba on October 23, 2001, as part of the NRC's scoping process to identify environmental issues specific to the plant. The results of the environmental review and a preliminary recommendation on the license renewal action were documented in NRC draft plant-specific Supplements 8 and 9 to the GEIS, which were issued on May 6, 2002, and May 13, 2002, for McGuire and Catawba, respectively. Four additional public meetings have been conducted, two near McGuire on June 12, 2002, and two near Catawba on June 27, 2002 (during the 75-day comment period for draft plant-specific Supplements 8 and 9 to the GEIS). At the meetings, the staff described the environmental review and answered questions from members of the public to help them formulate their comments on the review. Final Supplements 8 and 9 to the GEIS were issued in December 2002.

Draft Supplements 8 and 9 to the GEIS present the NRC's preliminary environmental analysis of the effects of renewing the McGuire and Catawba operating licenses for up to an additional 20 years. The analysis considers and weighs the environmental effects and alternatives that are available to avoid adverse environmental effects. On the basis of analyses and findings in the "Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants" (NUREG-1437), the environmental reports submitted by the applicant, consultation with other Federal, State, and local agencies, its own independent review, and its consideration of public comments, the staff recommended in Supplements 8 and 9 to NUREG-1437 that the Commission determine that the adverse environmental impacts of license renewal for McGuire and Catawba are not so great that preserving the option of license renewal for energy planning decisionmaking would be unreasonable.

## 1.3 Summary of Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the McGuire and Catawba LRA in accordance with Commission guidance and the requirements of 10 CFR 54.19, 54.21, 54.22, 54.23, and 54.25. The standards for renewing a license are contained in 10 CFR 54.29.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. Duke submitted this general information in Chapter 1 of its application for renewal of the McGuire and Catawba operating licenses. In 10 CFR 54.19(b), the Commission requires that LRAs include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The applicant states the following in Section 1.6 of its LRA regarding this issue:

> The current indemnity agreement for McGuire Nuclear Station (B-83) states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement. Item 3 of the Attachment to the indemnity agreement, as revised through Amendment No. 10, lists NPF-9 and NPF-17, the license numbers for McGuire Nuclear Station Units 1 and 2, respectively. Should the license numbers be changed upon issuance of the renewed licenses, Duke requests that conforming changes be made to Item 3 of the Attachment to Indemnity Agreement B-83, and any other sections of the indemnity agreement as appropriate.

> The current indemnity agreement for Catawba Nuclear Station (B-100) states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement. Item 3 of the Attachment to the indemnity agreement, as revised through Amendment No. 9, lists NPF-35 and NPF-52, the license numbers for Catawba Nuclear Station Units 1 and 2, respectively. Should the license numbers be changed upon issuance of the renewed licenses, Duke requests that conforming changes be made to Item 3 of the Attachment to Indemnity Agreement B-100, and any other sections of the indemnity agreement as appropriate.

The staff will use the original license number for the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility contain: (1) an integrated plant assessment (IPA), (2) current licensing basis changes during NRC review of the LRA, (3) an evaluation of TLAAs, and (4) an FSAR supplement. The applicant submitted the information required by 10 CFR 54.21(a), (c), and (d) in the Technical Information volume of the LRA. By letter dated June 25, 2002, the applicant submitted Amendment 1 to the LRA, which summarizes changes to the current licensing basis that have occurred at McGuire and Catawba during the staff's review of the LRA. This submittal satisfies the requirement of 10 CFR 54.21(b) and has been reviewed by the staff.

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. In Appendix D of the LRA, the applicant stated that no technical specification changes had been identified as being necessary to support issuance of the renewed operating licenses for McGuire 1 and 2 and Catawba 1 and 2.

The staff evaluated the technical information required by 10 CFR 54.21 and 54.22 in accordance with the NRC's regulations and the guidance provided in the initial draft SRP. The staff's evaluation of this information is documented in Chapters 2, 3, and 4 of this SER.

The staff's evaluation of the environmental information required by 10 CFR 54.23 is documented in the draft plant-specific supplements to the GEIS (NUREG-1437, Supplements 8 and 9).

### 1.3.1 Westinghouse Topical Reports

In accordance with 10 CFR 54.17(e), the applicant references certain Westinghouse Owners Group topical reports in each LRA. The applicant used topical reports to generically demonstrate that applicable aging effects for reactor coolant system components will be adequately managed for the period of extended operation.

- WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," Section 4.3.1, Westinghouse Electric Corporation, November 1996

- WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," Westinghouse Electric Corporation, November 1983

- WCAP-10585, “Technical Basis For Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis For McGuire Units 1 and 2,” June 1984, Westinghouse Electric Corporation

- WCAP-10546, “Technical Basis For Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis For Catawba Units 1 and 2,” June 1984, Westinghouse Electric Corporation

The staff issued the safety evaluation for WCAP-14535A on September 12, 1996. In accordance with the procedures provided in NUREG-0390, “Topical Report Review Status,” the staff requested that the Westinghouse Owners Group publish the accepted versions of the reports incorporating the transmittal letter and the staff's safety evaluation between the title page and the abstract. The accepted versions have an *A* (for “accepted”) after the report identification number.

The safety evaluations of the topical reports are intended to be stand-alone documents. An applicant incorporating the topical reports by reference into its LRA must ensure that the conditions of approval stated in the safety evaluations are met. The staff's evaluation of the applicant’s incorporation of the topical reports into the LRA is documented in Chapter 4 of this SER.

## 1.4 Summary of Open Items and Confirmatory Items

As a result of its review, the NRC staff issued an SER with open items on August 14, 2002, and identified and documented 41 open items and 4 confirmatory items. An issue was characterized as an open item if the applicant had not presented a sufficient basis for resolution, or if questions or concerns about the applicant’s license renewal application emerged late in the staff’s review, such that resolution could not be proposed by the applicant before the SER with open items was issued. An issue was characterized as confirmatory if the staff and applicant had agreed to a resolution, but information in official submittals from the applicant was needed. New open items involved issues that had not been the subject of staff RAIs. The applicant responded to the open and confirmatory items, as well as two other emerging issues pertaining to the treatment of electrical fuse holders and aging management of the pressurizer surge and spray nozzle thermal sleeves and the steam generator divider plates, in letters dated October 2, 2002, October 28, 2002, November 5, 2002, November 14, 2002, November 18, 2002, and November 21, 2002. The staff’s evaluation of the applicant’s responses to the emerging issues is documented in Sections 2.5.2.2, 3.1.2.2.1, and 3.6.1.2.1 of this SER.

The applicant’s responses to open and confirmatory items are described below.

<u>Open items 2.3-1 and 2.3-2.</u> The applicant failed to perform an AMR for the housings of active components (e.g., fans and dampers) that may perform critical pressure retention and/or structural integrity functions. Failure to maintain that function could prevent the associated active component from performing its function. Since these housings are within the scope of license renewal and are long-lived and passive, they are subject to an AMR in accordance with 10 CFR 54.21.

In its response to SER open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the fan and damper housings of ventilation systems that are in scope at McGuire and Catawba. The staff found the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER. The staff's evaluation of the AMR results is documented for applicable systems in Sections 3.2 and 3.3 of this SER.

<u>Open item 2.3-3.</u> The AMP (the Inspection Program for Civil Engineering Structures and Components) credited by the applicant for monitoring the aging of structures that include structural sealants as sub-components does not include, within its scope, building sealants. Therefore, this AMP was considered inadequate to manage the aging of building sealants, which are long-lived, passive structural sub-components within the scope of license renewal.

In its response to this open item, dated October 28, 2002, the applicant credited a visual inspection of the structural sealant used to maintain ventilation pressure boundary integrity of the control room area, emergency core cooling pump rooms, annulus, and fuel handling building. The staff found the applicant's response sufficient to resolve open item 2.3-3. The staff's evaluation of the Ventilation Area Pressure Boundary Sealants Inspection Program is documented in Section 3.0.3.19 of this SER.

<u>Open item 2.3.3.12.2-1.</u> By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.12-1, that the applicant provide the basis for not listing the turbocharger turbine flexible hoses in Table 3.3-15, since these components are passive, long-lived, and have intended functions to maintain pressure boundary. In its response dated April 15, 2002, the applicant stated that the flexible hose is replaced during periodic maintenance. The applicant implied that the hose is replaced based on qualified life in accordance with 10 CFR 54.21(a)(1)(i) and is, therefore, not subject to an AMR. However, since this was not clearly stated in the RAI response, this issue was characterized as an open item.

In its response to this open item, dated October 28, 2002, the applicant confirmed that the flexible hose in the diesel generator cooling water system is replaced on a qualified life every 6 years and, therefore, is not subject to an AMR. The staff agreed with this conclusion. Therefore, open item 2.3.3.12.2-1 is closed.

<u>Open item 2.3.3.13.2-1.</u> The applicant did not provide sufficient information in its response to RAI 2.3.3.13-1 to enable the staff to evaluate the adequacy of its replacement of synthetic rubber flexible expansion joints associated with the emergency diesel generator crankcase vacuum system during periodic maintenance. The applicant was requested either to (1) indicate if replacement of these components is based upon a qualified life or based upon condition or performance monitoring, or (2) specify the parameters that will be monitored as indicators of the components' condition or performance.

In its response to this open item, dated October 28, 2002, the applicant stated that the synthetic rubber flexible hoses on the inlet and outlet of the diesel generator crankcase vacuum blowers are inspected for cracking and signs of wear on a 6-year frequency and replaced based on condition. The staff found this to be an acceptable basis for excluding these hoses from an AMR. Therefore, open item 2.3.3.13.2-1 is closed.

Open item 2.3.3.14.2-1. The applicant did not provide sufficient information in its response to RAI 2.3.3.14-1 to enable the staff to evaluate the adequacy of its replacement of flexible hose connections associated with the emergency diesel generator fuel oil system during periodic maintenance. The applicant was requested either to (1) indicate if replacement of these components is based upon a qualified life or based upon condition or performance monitoring, or (2) specify the parameters that will be monitored as indicators of the components' condition or performance.

In its response to this open item, dated October 28, 2002, the applicant stated that the flexible hoses in the diesel generator fuel oil system are replaced on a qualified life every 6 years and, therefore, are not subject to an AMR. Since the component is replaced on a specified interval, the staff agreed with this conclusion. Therefore, open item 2.3.3.14.2-1 is closed.

Open item 2.3.3.19-1. McGuire UFSAR Section 9.5.1.2.1 states that fire hydrants are connected to the yard main. Furthermore, fire hydrants are considered passive and long-lived components in accordance with 10 CFR 54.21. Since the UFSAR is referenced in the license conditions for both McGuire and Catawba, and these components are discussed therein as providing a fire suppression function (which is required by 10 CFR 50.48), it appears that these components are required to meet the requirements of 10 CFR 50.48. The UFSAR does not distinguish between those fire hydrants that are required by 10 CFR 50.48 and those that are not. McGuire is required to meet Appendix A to BTP 9.5-1 and Catawba is required to meet the position documented in CMEB 9.5-1. Both documents state that "outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this, hydrants should be installed approximately every 250 feet on the yard main system." Therefore, the applicant was requested to furnish documentation that demonstrates that the excluded fire hydrants are not required by 10 CFR 50.48 or identify these hydrants as being within the scope of license renewal and subject to an AMR.

During a meeting with the staff on October 1, 2002, and in its formal response to this open item dated October 28, 2002, the applicant stated that the fire protection plant designs for McGuire and Catawba are unique. By design, most plants rely upon the hydrants for compliance with 10 CFR 50.48 as a backup means of suppression to ensure defense-in-depth. However, the fire protection system in the auxiliary buildings for McGuire and Catawba consists of two headers that feed the automatic and manual suppression systems. These headers provide sectional isolation capability between the automatic and manual suppression systems such that a single failure cannot cause loss of water supply to both the automatic and manual means of suppression in a given area. As such, defense-in-depth exists in the fire protection system design in the auxiliary building for McGuire and Catawba. In addition, Duke stated that no potential sources of radioactive releases are protected in the event of a fire by those hydrants that are excluded from the scope of license renewal at McGuire or Catawba. Since the applicant does not rely on the hydrants as a backup means of suppression or to protect against the release of radioactive releases for compliance to 10 CFR 50.48, SER open item 2.3.3.19-1 is closed.

Open item 2.3.3.19-2. Operating license conditions for McGuire and Catawba, Supplement 2 of the McGuire and Catawba Safety Evaluation Reports (SERs) for original licensing, and Section 9.5.1.2.1 of the McGuire and Catawba UFSARs indicate that jockey pumps are provided to prevent frequent starting of the fire pumps by maintaining pressure in the yard mains in accordance with Section 6.b of BTP CMEB 9.5-1 and NFPA 20. The staff was concerned that the applicant has misapplied the QA Condition 3 designation for license renewal scoping purposes and excluded jockey pumps from the scope of license renewal, although the licensing basis of the plants indicates that these jockey pumps are relied upon to perform a function required by 10 CFR 50.48.

In its response dated October 28, 2002, Duke identified the jockey pump casings, piping, and other components of the fire water pressure maintenance sub-system as within the scope of license renewal. The applicant also provided the AMR results for the pressure maintenance subsystem of the fire protection system containing the jockey pump. Therefore, the staff was satisfied with the resolution of this issue. Open item 2.3.3.19-2 is closed. The staff's evaluation of the AMR results for the fire water pressure maintenance sub-system is documented in Section 3.3.19.2 of this SER.

Open item 2.3.3.19-3. Duke did not identify Catawba fire suppression equipment that provides fire water to lower containment carbon filters as within the scope of license renewal. Section 9.5.1.2.1 of the UFSAR states that the interior fire water system provides a fixed water suppression system for charcoal filters. On pages 48-50 of Duke's revised response to Appendix A to BTP APCSB 9.5-1, submitted to the NRC by letter dated November 4, 1983, Duke stated that lower containment carbon filters are provided with fire suppression capability. According to NRC Inspection Report 50-369/02-05, 50-370/02-05, 50-413/02-05 and 50-414/02-05 (ADAMS Accession No. ML021280003), Duke Specification CNS-1465.00-00-0006 states that carbon filters are protected by built-in water spray systems. The staff did not believe that the applicant's distinction between charcoal and carbon filters was material.

In its response dated October 28, 2002, the applicant stated that it had performed further review and determined that the piping, sprinklers, and valve bodies associated with the Catawba reactor building charcoal filter unit sprinklers should have been identified as within the scope of license renewal and subject to aging management review. The applicant indicated that the components of this portion of the Catawba FP system were listed in Table 3.3-27 of the LRA. Since the fixed water suppression system for the charcoal filters was included in scope and subject to an AMR, the staff was satisfied with its resolution. Open item 2.3.3.19-3 is closed. The staff's evaluation of the AMR results is documented in Section 3.3.19.2 of this SER.

Open item 2.3.3.19-4. A license condition for McGuire and Catawba states that Duke Energy Corporation shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSARs for the respective facilities. Sections 9.5.1.2.1 and 9.5.1.2.2 of the UFSARs state that manual hose stations and automatic sprinkler or deluge systems are provided for the protection of the oil storage house, the oxygen and acetylene gas storage yard area, the compressed flammable gas cylinder storage area, the main turbine piping and bearings, the unit start-up and standby oil-filled power transformers, the main turbine lube oil reservoirs, the hydrogen seal oil unit, and the feedwater pump turbines. The UFSARs do not differentiate between those manual hose stations and automatic sprinklers that are required to comply with 10 CFR 50.48 and those that are not. Additionally, the regulations governing fire protection apply to more than the protection of structures and equipment relied upon for safe plant shutdown. Therefore, the applicant was requested to furnish documentation that demonstrates that the fire protection features are not required by 10 CFR 50.48 or identify the components associated with these manual hose stations and automatic sprinkler or deluge systems as being within the scope of license renewal and subject to an AMR.

In its October 28, 2002, response to this open item, the applicant stated that separation was the only credited fire protection feature for those areas listed in the open item that are located in the yard. The staff agreed with the applicant's finding that the suppression systems in the outlying plant areas did not appear to be credited due to physical separation from surrounding buildings. In an augmented response dated November 18, 2002, the applicant stated that, although it disagreed with the staff's position with respect to manual hose stations in the turbine buildings, the equipment associated with these fire suppression features would be included in the scope of license renewal. The applicant also provided AMR results tables for the passive equipment brought into the scope of license renewal. Therefore, open item 2.3.3.19-4 is resolved. The staff's evaluation of the AMR results is documented in Section 3.3.19.2.

Open item 2.3.3.19-5. The staff agreed with the applicant that the strainers perform an intended function that meets one of the scoping criteria, specifically 10 CFR 54.4(a)(3). The staff's technical concern is that Duke uses lake water to supply their fire protection suppression systems at McGuire and Catawba. Lake water is corrosive and may contain sediment, which can potentially clog the fire pumps. In addition, the strainers keep debris from plugging the sprinkler nozzles in fire suppression systems in the event that sprinklers are actuated. This FP component should be managed in an AMP. However, the staff was concerned that the strainers were inappropriately screened out. Although the strainers may be in-line with and connected to the main fire pump, their function is passive (as is the pump casing's function). Since the applicant included the pump casings within the scope of license renewal, the staff believed that the strainers also should be within scope.

In its response dated October 28, 2002, the applicant stated that it had performed an AMR for the main fire pump strainers and provided the results of its review. These AMR results for the strainers were generically applicable to both McGuire and Catawba. The applicant indicated that each pump has a strainer that is within the scope of license renewal and is subject to AMR because it is a long-lived, passive component. This staff was satisfied with the resolution of this issue. Open item 2.3.3.19-5 is closed. The staff's evaluation of the AMR results is documented in Section 3.3.19.2 of this SER.

New open Item 2.3.3.19-6. 10 CFR 50.48 requires each operating nuclear station to have a fire protection plan. A license condition for McGuire and Catawba states that Duke Energy Corporation shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR for the respective facilities. Section 9.5.1.2.3, "Fire Protection, Category I Safety Related," of the McGuire UFSAR states that the manually operated water spray systems provide fixed spray patterns of water for Reactor Building Purge Exhaust Filters 1A, 1B, 2A and 2B. However, drawing MCFD 1599-02.01, coordinates H-3, G-3, C-5 and B-7, indicates that piping and sprinklers associated with this function are also excluded from scope. The staff was concerned that the manually operated water spray systems for these filters were inappropriately excluded from the scope of license renewal and an AMR.

In its response dated October 28, 2002, the applicant stated that the flexible hoses, piping, sprinklers, and valve bodies associated with the McGuire reactor building exhaust filters spray system should have been identified as within the scope of license renewal and subject to aging management review. The components of this portion of the McGuire FP system are listed in Table 3.3-26 of the LRA. The staff was satisfied with the resolution of this issue. Open item 2.3.3.19-6 is closed. The staff's evaluation of the AMR results provided in Table 3.3-26 of the LRA is documented in Section 3.3.19.2 of this SER.

Open item 2.3.3.35.2-1. The applicant did not provide sufficient information in its response to RAI 2.3.3.35-3 to enable the staff to evaluate the adequacy of its replacement of flexible hose connections associated with the standby shutdown diesel generator fuel oil sub-system during periodic maintenance. The applicant should indicate if replacement of these components is based upon a qualified life or based upon condition or performance monitoring. If replacement is based upon the latter, the applicant should specify the parameters that will be monitored as indicators of the components' condition or performance.

In its response to this open item, dated October 28, 2002, the applicant stated that the flexible hoses in the standby shutdown diesel generator fuel oil subsystem are inspected for cracking and signs of wear on an 18-month frequency and replaced based on condition. The staff found this to be an acceptable basis for excluding these hoses from an AMR. Therefore, open item 2.3.3.35.2-1 is closed.

Open item 2.5-1. By letter dated June 26, 2002, the applicant provided AMR results for the passive, long-lived structures and components associated with the offsite power path. Pending completion of the staff's review of this information, this item was characterized as open.

In its June 26, 2002, letter, the applicant indicated that the following passive component commodity groups (that were originally identified as out of scope) have been identified as being within the scope of license renewal and subject to an AMR: high-voltage insulators, phase bus (e.g., isolated-phase bus, nonsegregated-phase bus, bus duct), switchyard bus, and transmission conductors. In a letter dated October 2, 2002, the applicant clarified its response to SER open item 2.5-1, stating that all insulated cables and connections (power, control, and instrumentation applications) installed in the additional areas identified in the SBO open item response were, and still are, in scope as part of a bounding scope. The applicant also provided, in a letter dated October 28, 2002, a simplified one-line diagram of the SBO power recovery path and further clarified that insulated cables and connections included as part of the SBO power recovery path are considered to be part of the larger component commodity group, which includes all insulated cables and connections. Cables and connections in the SBO power recovery path were considered by the applicant to be within the scope of license renewal and subject to an AMR. Since the long-lived, passive component associated with the offsite power path for recovery from SBO events was included within the scope of license renewal in accordance with 10 CFR 54.4(a)(3), open item 2.5-1 is closed.

New open item 3.0.3.2.3-1. 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 should include a discussion in the FSAR supplement regarding the specific technical specifications and the EPRI guidelines that are mentioned in Appendix B for the Chemistry Control Program.

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). The applicant also augmented its McGuire and Catawba FSAR supplements to indicate that 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 found that the revised FSAR supplement is consistent with the program described in Appendix B of the LRA and considers open item 3.0.3.2.3-1 closed.

New open item 3.0.3.9.1.2(a-g). The applicant's acceptance criteria for heat exchanger preventive maintenance are not adequate to provide the staff with reasonable assurance that loss of material of the heat exchanger components will be adequately managed or monitored such that the intended functions of the heat exchangers will be maintained during the extended period of operation. This open item applies to seven aging management activities (a through f).

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 50.55a) and other pertinent factors in determining the acceptance criteria for loss of material, the staff found the applicant's response to SER open item acceptable. Therefore, open item 3.0.3.9.1.2 (a) is closed.

In its response to SER open item 3.0.3.9.1.2(b-g), dated October 28, 2002, 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 applicant further explained that eddy current testing at McGuire and Catawba is performed by a vendor who specializes in the practice, and that a four-step process is used to determine if test results are acceptable and generate the final test report. This process was described in detail in the applicant's October 28, 2002, response to this SER open item. The staff found that appropriate and adequate acceptance criteria for detecting heat exchanger tube degradation from loss of material were identified for these aging management programs. Therefore, open items 3.0.3.9.1.2 (b-g) are closed.

New open item 3.0.3.10.2-1. Since 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 staff believed that volumetric examination of a sample of small-bore Class-1 piping was needed to demonstrate that the effects of aging are being adequately managed during the period of extended operation. The staff also believed that a sample of affected welds selected for inspection should be based upon piping geometry, pipe size and flow conditions, and that the inspection should be performed by qualified personnel using approved station procedures.

In its response dated November 14, 2002, the applicant stated 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 also will be addressed. The applicant further indicated that 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. By letter dated November 21, 2002, the applicant augmented its response to clarify how the Small Bore Piping Examination will be implemented at McGuire and Catawba. The applicant stated that it 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's November 14, 2002, response to this open item. 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. Since volumetric inspection will ensure that the inspections of the small bore piping components will be capable of detecting cracking in the components, the staff considers SER open item 3.0.3.10.2-1 closed.

<u>New open item 3.0.3.10.2-2.</u> In October 2000, a through-wall crack was identified in the reactor vessel hot leg piping at V.C. Summer. 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 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 plans to take to address this operating experience as it applies to McGuire and Catawba.

In its response to open item 3.0.3.10.2-2, dated October 28, 2002, the applicant specified the McGuire and Catawba reactor coolant system piping that contains welds fabricated from Alloy 82/182 material, and the applicant described the actions it has taken, and will take in the future, to address this operating experience as it applies to McGuire and Catawba. The applicant further 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 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.

<u>New open item 3.0.3.11.3-1.</u> The FSAR supplements did not include references to several of the important industry codes and standards discussed in the applicant's March 11, 2002, response to the staff's RAIs on the Inspection Program for Civil Engineering Structures and Components. The staff requested the applicant to submit an updated summary description of the program to reflect these codes and standards.

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.

<u>New open item 3.0.3.13.2-1.</u> In the case of the buried piping, the staff finds the applicant's Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection 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 the most vulnerable locations.

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, the staff notified the applicant that open item 3.0.3.13.2-1 was considered resolved. 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. 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. The degree of degradation of the inside coating can give some idea of the condition of the outside coating. Since the sample of internal pipe at McGuire and Catawba 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. Additionally, the staff found a similar inspection program for Oconee acceptable. Therefore, open item 3.0.3.13.2-1 is considered closed.

<u>New open item 3.0.3.15.2-1.</u> In its description of the Service Water Piping Corrosion program, Monitoring and Trending element, the applicant stated that localized corrosion due to pitting and MIC will reveal itself through pinhole leaks in the piping components, that they are not a structural integrity concern, and that they cannot individually lead to loss of the component's intended function, since sufficient flow at prescribed pressures can still be provided by the system. The applicant also stated that these localized concerns will lead to structural integrity concerns only when a significant number of pinholes are present and that a trend of indications of through-wall leaks will trigger corrective actions. However, the staff believed that localized corrosion can result in the loss of the intended function to maintain pressure boundary 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).

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 a 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 taking appropriate corrective actions. The staff found 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.

<u>New open item 3.0.3.18.3-1.</u> The FSAR supplements did not include references to some important industry standards and the NRC guidelines used for the Underwater Inspection of

Nuclear Service Water Structures program. The staff requested that the applicant revise its FSAR supplements for McGuire and Catawba to reflect these standards and guidelines.

In its response dated October 2, 2002, the applicant provided a revised FSAR supplement that included the appropriate industry standards. The staff found 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.

<u>New open item 3.1.2.2.2-1.</u> Under the Monitoring and Trending element of the Pressurizer Spray Head Examination, the applicant stated that a visual examination (VT-3) would be performed, and that no actions are taken as part of this program to trend inspection or test results. However, the staff's position is that VT-3 examinations may not be capable of detecting cracks that may occur in the pressurizer spray head. The staff therefore 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. The scope of this open item included the potential need to revise the acceptance criteria for this program and the FSAR supplement summary description.

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 will be 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 UFSAR supplement. The applicant's response indicated 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 resolves the issue raised in open item 3.1.2.2.2-1. Therefore, the staff considers open item 3.1.2.2.2.-1 to be closed.

<u>New open item 3.1.3.2.2-1.</u> The staff reviewed the surveillance capsule schedules in Tables B.3.26-1 and B.3.26-2 of the LRA. For McGuire 1, capsule "W" is a standby capsule and would be withdrawn at a fluence that is significantly above the equivalent of 60 years. The staff was concerned that the applicant would need to remove this capsule and place it in storage to prevent further exposure and preserve its ability to provide meaningful metallurgical data. For Catawba 2, the staff was concerned that capsule "U" (a standby capsule) would need to be inserted in the reactor vessel and begin to accumulate fluences in an operating environment for data collection purposes. The staff believed that the applicant should place all pulled capsules in storage so that they may be saved for future use. In addition, the staff believed that, after the applicant has pulled all the capsules, it should use alternative dosimetry to monitor neutron fluence during the period of extended operation. The staff requested the applicant to describe its plans for this capsule.

In its response to open item 3.1.3.2.2-1, dated October 28, 2002, the applicant identified those surveillance capsules that are in storage and those that are available for further testing if necessary. The applicant discussed its RV material surveillance programs for McGuire and

Catawba and clarified its plans for removal and testing of surveillance capsule W (for McGuire 1) and surveillance capsule U (for Catawba 2). The staff concluded that the surveillance program is acceptable for the period of extended operation for all units and considers open item 3.1.3.2.2-1 closed.

New open item 3.1.3.2.2-2. 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 are emerging, current license issues that have not yet been resolved and, pursuant to 10 CFR 54.30(b), are beyond the scope of this license renewal review. 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, the NEI, Materials Reliability Project (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, 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. Any updates to the VHP Nozzle Program that result from resolution of this issue should be reflected in the McGuire and Catawba UFSARs.

In its response dated October 28, 2002, 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. 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 found that there was 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.

New open item 3.1.4-1(a). Since the fabricator for the McGuire 1 and Catawba 2 RVs is not the same as the design fabricators for McGuire 2 and Catawba 1 RVs or for the Oconee RVs, some uncertainty exists whether the inspections of welded RV internals at Oconee 1 and McGuire 1 will be truly representative of the condition of welded RV internals at McGuire 2 and the Catawba units. The staff believed that the applicant should schedule inspections of remaining RV internal plates, forgings, welds and bolts (i.e., core barrel bolts and thermal shield bolts) at all of the McGuire and Catawba reactor units.

In its response to open item 3.1.4-1(a), dated October 28, 2002, the applicant clarified that all of the RV internals for the McGuire and Catawba units were manufactured by Westinghouse, not by the fabricators of the RVs (i.e., neither Combustion Engineering nor Rotterdam Drydock fabricated the RV internals). The applicant provided an acceptable design-feature-based argument for concluding the baffle bolts and plates at McGuire were limiting in regard to the temperatures and fluences the materials would achieve when compared to those in the Catawba units, and stated that it would inspect the RV internals at both McGuire 1 and McGuire 2 during the periods of extended operation for the units and to use the results of the examinations as the basis for determining whether additional inspections of the RV internals at Catawba 1 and Catawba 2 would be necessary. The applicant stated that the RV internals at McGuire 1 will be inspected during the fifth ISI interval for the unit, and the RV internals at McGuire 2 will be inspected during the sixth ISI interval for the unit. Based on this response, the applicant will be performing inspections of the RV internals at five of the seven Duke-owned nuclear reactors (i.e., at Oconee and McGuire). Since the McGuire RV internals are projected to be limiting in comparison to those at Catawba, the staff concluded that the applicant's credited inspections for the RV internal core barrel components at McGuire (and at Oconee) will provide an acceptable basis for determining whether age-related degradation is applicable in the corresponding components at Catawba and for scheduling inspections at Catawba as necessary. This resolves open item 3.1.4-1(a).

<u>New open item 3.1.4-1(b).</u> The critical crack size acceptance criterion for RV internal forgings, plates, and welds, and RV internals made from CASS had not yet been established. Nor had any acceptance criteria been proposed for the inspections that might be proposed to monitor the RV internals for void swelling. The applicant will need to submit the critical crack size acceptance criteria for the RV internal forgings, plates, and welds, and RV internals made from CASS once the evaluations for these components have been completed and the critical crack sizes for these components have been established. Once the applicant has finalized its evaluation of void swelling of the RV internals, the applicant will also need to submit the acceptance criteria for dimensional changes that might result in the RV internal components as a result of void swelling. The staff requested a commitment from the staff to determine the critical crack size and submit this acceptance criterion (when it has been determined) to the staff.

In its response to open item 3.1.4-1(b), dated October 28, 2002, the applicant provided a summary description of the Acceptance Criteria attribute of the Reactor Vessel Internals Inspection for each station's FSAR supplement to address the need to submit the acceptance criteria established by industry programs for evaluating cracking, loss of fracture toughness, and void swelling in Westinghouse-designed RV internals to the staff for review and approval. This is acceptable to the staff, since the industry is currently in the progress of establishing what the techniques and acceptance criteria will be for evaluation of these aging effects in Westinghouse-designed RV internals. This resolves open item 3.1.4-1(b).

<u>New open item 3.1.4-1(c).</u> The staff requested the applicant to provide a commitment to update the "Detection of Aging Effects" program attribute in FSAR Supplement Section 18.2.22, "Reactor Vessel Internals Inspection," to reflect the second paragraph in the applicant's response to RAI B.27-2. This part of open item 3.1.4-1 was not identified in the SER with open items. For tracking purposes, the staff and applicant characterized this issue as SER open item 3.1.4-1(c).

In its response to open item 3.1.4-1(c), dated October 28, 2002, the applicant stated that the FSAR supplements for McGuire and Catawba will be revised to incorporate a statement that the visual inspection method selected for the inspection of RV internal plates, forging, and welds will be sufficient to detect cracks in the components prior to any growth to a size that is greater than the critical crack size (critical crack length) for the material. In its response, the applicant acknowledged that, for visual inspections of RV internals at McGuire and Catawba, it must implement a visual inspection technique that is capable of detecting surface cracks in the internal components. This acknowledgment resolves open item 3.1.4-1(c).

New open item 3.1.5-1. The staff requested the applicant to include a reference to NEI 97-06 in a summary description of the Steam Generator Surveillance Program or in Table 18-1 of the McGuire and Catawba FSAR supplements.

In its response dated October 28, 2002, the applicant provided a modified FSAR supplement summary description of this program. The revised FSAR supplement included a statement that inspections of the steam generator surveillance program follow the recommendations of NEI 97-06, "Steam Generator Program Guidelines." The staff found the changes acceptable because the modified FSAR supplement summary description will be consistent with the steam generator surveillance program described in Appendix B, Section B.3.31, of the Catawba and McGuire LRA. The staff considers open item 3.1.5-1 closed.

New open item 3.3.6.2.1-1. In its response to RAI 2.3.3.6-6, the applicant provided the AMR results for condenser circulating water system expansion joints at Catawba. The material for these expansion joints was specified as synthetic rubber coated with chlorobutyl rubber; the environment was specified as the yard. The applicant did not identify any aging effects; nor did the applicant specify any AMP for these components. However, the staff concluded that exposure of these expansion joints to ultraviolet (UV) rays could cause degradation over time. Because the applicant's description of the yard environment in the LRA did not address sun exposure, the staff was unable to verify that there are no applicable aging effects for these components. The applicant was requested to submit a more detailed description of the yard environment for the condenser circulating water system expansion joints to address UV exposure.

In its response dated November 14, 2002, the applicant agreed to add cracking and wear as potential aging effects and addressed the issue of potential degradation of the synthetic rubber expansion joint in the condenser circulating water system. The applicant stated that it would implement a one-time inspection of the expansion joints in order to characterize any cracking and wear of expansion joints exposed to raw water internal and the yard external environments. The applicant stated that, based on current operating experience, one-time inspection of the expansion joints will be adequate for protecting the system. The staff reviewed the AMR results and concluded that the aging effects specified for the expansion joint were consistent with industry experience for these combinations of materials and environments. The staff also evaluated the one-time inspection credited for these components and found that there was reasonable assurance that the applicant had demonstrated that the effects of aging associated with the one-time inspection of the expansion joints in the condenser circulating water system 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). Therefore, the staff considers open item 3.3.6.2.1-1 resolved.

New open item 3.3.17.2.1-1. In its response to RAI 2.3.3.17-2, the applicant provided the AMR results for a carbon steel emergency diesel generator starting air distributor filter in a sheltered environment. The applicant indicated that no aging effects were identified for this component. However, the staff noted that this conclusion was not consistent with the applicant's treatment of other carbon steel components in a sheltered (moist air) environment that are listed in Table 3.3-23, "Aging Management Review Results - Diesel Generator Starting Air System (McGuire Nuclear Station)." The applicant was requested to explain why the carbon steel emergency diesel generator starting air distributor filter in a sheltered environment is not subject to loss of material or to identify this aging effect and an AMP to manage or monitor the associated loss of material.

In its response dated October 28, 2002, the applicant provided a revised AMR results table for the diesel generator starting air distributor filter. The applicant specified loss of material as an aging effect and credited the Inspection Program for Civil Engineering Structures and Components. The aging effect specified is consistent with industry experience for the material and environment specified. Therefore, this response is acceptable to the staff and resolves open item 3.3.17.2.1-1.

Open item 3.3.35.2-1. The staff requested additional information pertaining to Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator." This table indicates that the cooling water and jacket water engine radiator heat exchanger has a heat transfer function that is managed by the Chemistry Control Program. Heat transfer monitoring is not identified as a capability of the Chemistry Control Program, as defined in Appendix B, Section B.3.6. The applicant was requested to explain how the Chemistry Control Program monitors the heat transfer function. In its response, the applicant stated that for the heat exchangers in the standby shutdown diesel generator cooling water and jacket water heating sub-system, fouling would not occur because there is constant flow through the heat exchangers and because the treated water in the system is filtered to remove particles. Therefore, no aging management program is required. The staff did not agree with the applicant's conclusion that fouling will not occur in the heat exchanger because of the constant flow through the heat exchanger. The staff recognized that sufficient flow through the heat exchanger may prevent areas of stagnation in which fouling may occur. However, the applicant had not substantiated its conclusion with any operating experience, such as maintenance and surveillance results, to demonstrate the success of this activity in preventing fouling. With respect to the filtering of the treated water to remove particles, the staff recognized that particulates are removed through a filtering process. However, the applicant did not list or credit a periodic surveillance of the filter to ensure that the entrained particles do not create a high differential pressure and adversely affect flow through the heat exchanger.

In its response dated October 28, 2002, the applicant identified fouling due to silting as an aging effect requiring management for the heat exchanger in the standby shutdown diesel cooling water and jacket water heating subsystem. The applicant further clarified that the standby shutdown diesel cooling water and jacket water heating subsystems are closed cooling water systems treated with corrosion inhibitors. The Chemistry Control Program was credited for managing fouling. The staff found that the clarifications and changes provided by the applicant are appropriate to ensure that the aging effects associated with the heat exchanger in the standby shutdown diesel cooling water and jacket water heating subsystem will be adequately managed during the period of extended operation. The identification of fouling as an aging effect and its management through corrosion inhibitors monitored by the Chemistry

Control Program were acceptable because the program precludes the formation of corrosion products that can cause the fouling of the heat exchanger and adversely impact the heat transfer function. Therefore, open item 3.3.35.2-1 is closed.

New open item 3.4.1.2.2-1. The applicant proposed to mitigate general corrosion and loss of material of the auxiliary feedwater system carbon steel piping components by chemistry control. However, the staff believed that the effectiveness of the Chemistry Control Program should be verified by implementing a one-time inspection of the internal surfaces of these components.

In its response dated October 28, 2002, the applicant stated that it had searched the operating experience database to determine if there had been any component failures, relevant industry operating experience, or problems discovered during routine maintenance and testing. The applicant did not find any loss of the intended functions of the auxiliary feedwater system components that could be attributed to the inadequacy of the chemistry control program. The applicant stated that routine maintenance of other secondary system components, such as the steam generators and main turbine, provides additional operating experience because they do operate during startup and shutdown and are of the same chemistry as the feedwater system and other secondary side systems. These secondary systems have also shown no degradation affected by water chemistry. However, the applicant added a statement to Section 18.3 of the McGuire and Catawba FSAR supplements to indicate that visual inspections of the interior surfaces of auxiliary feedwater system and main feedwater system components and piping will be performed when available, and that the inspection results will be documented in writing and available for inspection following issuance of renewed operating licenses for McGuire and Catawba. The staff finds the augmented Catawba and McGuire FSAR supplements acceptable because the applicant will inspect these internal surfaces specifically for aging effects (loss of material) and will document its findings in the inspection procedure. This deliberate inspection will provide an opportunity to verify that the Chemistry Control Program is effective and thereby satisfies the intent of the one-time inspection. The staff considers open item 3.4.1.2.2-1 closed.

Open item 3.5-1. Contrary to the applicant's claim that aging management of concrete components via periodic inspections is only necessary for concrete SCs that are exposed to harsh environments, the staff's position is that both the operating and environmental conditions, as well as the aging of concrete nuclear components, are subject to change throughout the period of extended operation. Therefore, the staff believed the applicant should periodically inspect these components. Although the applicant had performed an aging management review pursuant to 10 CFR 54.21(a)(3) for each structure and component that was determined to be in the scope of license renewal, the staff's position (issued by letters dated November 23, 2001, and April 5, 2002, is that aging management reviews should be used to differentiate between those components requiring only periodic inspections and those requiring further evaluation. Aging management review results of concrete structures and components may also be used to establish different scheduled inspection frequencies, similar to those recommended by American Concrete Institute 349.3R, for aging management programs. The staff was concerned that the applicant had not proposed periodic inspections of concrete components during the period of extended operation. Therefore, the staff was unable to make a reasonable assurance finding that in-scope concrete structures and components would maintain their structural integrity and intended functions.

In its response dated October 2, 2002, the applicant agreed to resolve open item 3.5-1 by committing to manage the aging of accessible concrete structural components during the period of extended operation. In a letter dated October 28, 2002, the applicant submitted revised AMR results tables for Section 3.5 of its LRA. In a letter dated November 14, 2002, the applicant state that it would manage loss of material, cracking, and change in material properties for the accessible concrete components identified in Tables 3.5-1 and 3.5-2 of the LRA. The applicant credited the Inspection Program for Civil Engineering Structures and Components to manage the specified aging effects. The applicant's periodic inspection of accessible concrete structures and components through its Inspection Program for Civil Engineering Structures and Components is acceptable to the staff. Therefore, open item 3.5-1 is closed.

Open item 3.5-2. The staff expressed concern that the applicant did not plan to periodically monitor groundwater during the extended period of operation to confirm that it is not aggressive to buried portions of concrete structures. As stated in the applicant's response to RAI 3.5.1, the chloride, sulfate, and pH values over the past 20 to 30 years are well below the limits where potential degradation of concrete may occur. In addition, the water contour tables for both Catawba and McGuire show that the water table levels decrease from the two nuclear stations outward to the surrounding areas such that only a chemical event at the nuclear stations would potentially impact their respective site environments, including the groundwater. However, in its response to RAI 3.5-1, the applicant did not commit to initiate corrective action in the event of a potential change to the site environment resulting from a chemical release during the period of extended operation. Such a corrective action would need to include a commitment to monitor the groundwater chemistry and to assess the potential impact of any changes to the groundwater chemistry on below-grade concrete components.

In a letter dated July 9, 2002, the applicant stated that it did not commit to initiate a corrective action in the event of a potential change to the site environment resulting from a chemical release during the period of extended operation, because such an event was not postulated. The applicant stated that it was not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Catawba or McGuire. A change in the environment due to a chemical release would be an abnormal event. The staff reviewed NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," and determined that aging effects from abnormal events need not be postulated specifically for license renewal. After the SER was issued with this identified as open item 3.5-2, the staff reviewed the guidance provided in NUREG-1800 and reconsidered the applicant's assertion that a potential change to the site environment resulting from a chemical release during the period of extended operation would be an abnormal event. The staff agreed that such a chemical release would not need to be postulated for the purposes of performing an aging management review for license renewal. Therefore, the staff closed open item 3.5-2 without any further information from the applicant. The applicant was notified of this resolution by electronic correspondence dated September 3, 2002.

Open item 3.5-3. Since the ice condenser wear slab, structural concrete floor, and crane wall were characterized as inaccessible and in a unique environment of low humidity and temperature, the staff acknowledged that there are no accessible concrete components in a similar environment that the applicant could use as an indicator of the aging of these inaccessible ice condenser components. However, the applicant indicated in its response to RAI 3.5-6 that portions of both the structural concrete floor, which is located beneath the ice condenser wear slab, and the crane wall are accessible for inspection. Specifically, the applicant stated that the structural concrete floor is accessible from below, and that the interior surface of the crane wall is open to the reactor building environment and accessible for inspection. For the ice condenser wear slab, the applicant indicated that a protective layer of ice would prevent water from coming into contact with the wear slab. Since the applicant did not plan to inspect potentially accessible portions of the ice condenser crane wall or accessible portions of the ice condenser structural concrete floor, the staff could not conclude, with reasonable assurance, that these concrete structures would be adequately monitored to ensure that their intended functions will be maintained during the extended period of operation.

In its response to open item 3.5-3, dated October 2, 2002, the applicant stated it had performed an additional review of the design of McGuire and Catawba and determined that the ice condenser wear slab was not within the scope of license renewal because it did not perform a license renewal function. With respect to the other structures identified in the SER open item, the applicant stated that it disagreed with the staff's conclusion that these structural components require aging management for the period of extended operation. Nonetheless, the applicant stated that it would perform periodic inspections of the accessible portions of the crane wall and ice condenser structural concrete floor during the period of extended operation as part of the Inspection Program for Civil Engineering Structures and Components. Since the ice condenser wear slab does not perform an intended function that meets the license renewal scoping criteria specified in 10 CFR 54.4, the staff agrees with the applicant's finding that the wear slab should not have been included within the scope of license renewal. The staff's review of this item is documented in Section 2.4.1.3.2 of this SER. In addition, since the applicant stated that it would manage the aging effects for the accessible portions of the crane wall and ice condenser structural concrete floor during the period of extended operation (as indicated in its response to SER open item 3.5-1), the staff considers open item 3.5-3 to be closed.

<u>New open item 3.5-4.</u> Neither the FSAR supplement nor the referenced TS and SLCs provided adequate descriptions of the Battery Rack Inspections. The applicant was requested to provide a summary description characterizing the important elements of the Battery Rack Inspections from Section B.3.2 of the LRA and the applicant's response to RAI B.3.2-1.

In its response dated October 2, 2002, the applicant provided a revision to Table 18-1 and Section 18.3 of the FSAR supplements for McGuire and Catawba. The revised FSAR supplements specified that inspections of the structural supports and anchorages of the battery racks would be performed. The staff found the applicant's revisions acceptable, since inspection of these specific sub-components of the battery rack structures was specified. Open item 3.5-4 is considered closed.

<u>New open item 3.5-5.</u> The staff reviewed the FSAR supplement provided in Appendix A-1 and Appendix A-2 of the LRA for McGuire and Catawba, respectively, and compared this information to that provided in Section B.3.10 of the LRA and the clarifications provided by the applicant in response to RAI B.3.10-1. Some important industry standards and the NRC guidelines used for the AMP were not incorporated into Section 18.2.7 of the FSAR supplement. The applicant was requested to update the FSAR supplements to incorporate the standards and guidelines.

In its response dated October 2, 2002, the applicant submitted revised McGuire and Catawba summary descriptions of the Monitoring and Trending attribute for this inspection program, which incorporated reference to the codes and standards listed in the RAI response. The staff found the applicant's revision to the FSAR supplements acceptable because the revisions ensure that the program will be governed by these codes and standards. Therefore, open item 3.5-5 is closed.

<u>Open item 3.6.1-1.</u> The applicant was requested to provide a technical justification that would demonstrate that visual inspection of high range radiation monitor and high voltage neutron monitoring instrumentation cables would be effective in detecting aging before current leakage could affect instrument loop accuracy.

In its response to open item 3.6.1-1, dated October 2, 2002, the applicant reiterated its view that visual inspections have proven to be effective and useful because visual inspections have revealed potential problems. In a subsequent response dated November 14, 2002, the applicant stated that it will implement a program specifically to resolve open Item 3.6.1-1. The name of this program is the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits. The scope of this program includes only non-EQ neutron flux instrumentation cables that are within the scope of license renewal. The other cables under discussion here, high-range radiation monitors/cables and the wide-range neutron flux monitors/cables, are included in the McGuire and Catawba EQ program and already covered for license renewal by this program. The staff found the applicant's response to SER open item 3.6.1-1 acceptable because the applicant will implement an AMP to monitor the aging of these sensitive cables. The staff also determined that the program established reasonable assurance that the intended function of electrical cables that are (1) not subject to the EQ requirement of 10 CFR 50.49, and (2) used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation. Therefore, open item 3.6.1-1 is closed.

<u>New open item 4.2-1 (not identified in the SER with open items).</u> By letter dated September 13, 2002, the staff requested additional information regarding the impact of the fracture toughness data from the Diablo Canyon 2 surveillance capsule on the PTS assessments for the longitudinal RV beltline welds fabricated from heat No. 21935/12002 at the end of the extended operating term (or end of life extended or EOLE). For tracking purposes, this request was characterized by the staff as open item 4.2-1.

In its response to open item 4.2-1, dated October 28, 2002, the applicant provided revised PTS and USE evaluations for these welds. The staff independently assessed the applicant's response to open item 4.2-1 and revised PTS and USE evaluations for the McGuire 1 RV welds and concluded that the revised $RT_{PTS}$ value for these welds at end of life extended meets the screening criterion for longitudinal welds as stated in the PTS rule and demonstrates that the McGuire 1 RV will comply with the fracture toughness and PTS criteria of 10 CFR 50.61 through the end of the extended period of operation for McGuire 1.

The staff also concluded that the revised USE value for applicable welds at EOLE is above 50 ft-lb screening criterion of the rule for ferritic materials in the irradiated condition and demonstrates that the McGuire 1 RV will comply with the USE screening criteria of 10 CFR Part 50, Appendix G, Section IV.A.1, through the expiration of the extended period of operation for McGuire 1. Therefore, the staff concludes that the applicant's TLAA for the PTS and USE evaluations of McGuire 1 are acceptable pursuant to 10 CFR 54.21(c)(1)(ii). This resolves open item 4.2-1.

Open item 4.3-1. In its response to a staff request for pressurizer sub-component cumulative usage factors (CUFs), the applicant indicated that modified operating procedures had been implemented at McGuire and Catawba to mitigate the effects of insurge/outsurge. In addition, historical plant instrument data were analyzed to determine the insurge/outsurge history both before and after modification of the operating procedures. The applicant indicated that an analysis including these events found that the design CUFs of all components will remain less than 1.0. By letter dated July 9, 2002, the applicant provided the CUFs for the sub-components listed in Table 2-10 of WCAP-14574-A, but did not discuss the impact of the environmental fatigue correlations on these sub-components. Pending completion of the staff's review of the information provided and assessment of the impact of the environmental correlations for these sub-components, this issue was characterized as an open item.

In its letter dated July 9, 2002, the applicant identified several pressurizer sub-components with relatively high design CUFs for McGuire and Catawba. These sub-components include the shell, spray nozzle, lower head heater penetration and nozzle weld, instrument nozzle, and surge nozzle. An assessment by the staff applying a conservative estimate of the environmental factor to these locations indicated that the CUFs may exceed 1.0 during the period of extended operation. However, Turkey Point and North Anna/Surry license renewal applicants used a combination of quantitative and qualitative assessments to argue that the actual CUFs, including environmental effects, are not expected to exceed 1.0 during the period of extended operation. If similar quantitative and qualitative assessments were performed for McGuire and Catawba, the staff would expect similar results to be obtained because McGuire and Catawba are Westinghouse NSSS designs, like Turkey Point, North Anna and Surry. The applicant stated that it would perform further evaluation of the surge line nozzle during the period of extended operation. The staff concludes that the applicant can use the surge line nozzle evaluation as a representative sample to address environmental effects on pressurizer sub-components for McGuire and Catawba during the period of extended operation. If the further evaluation of the surge line identifies the need for additional actions during the period of extended operation, then the applicant should demonstrate the acceptability of pressurizer sub-components, considering environmental fatigue effects, as part of its corrective action. The staff considers open item 4.3-1 closed.

New open item 4.3-2. By letter dated July 9, 2002, the applicant provided a table of CUFs for newer-vintage Westinghouse plant locations identified in NUREG/CR-6260. The staff's review of these data is ongoing. The Catawba UFSAR lists a large number of design cycles for charging and letdown flow changes. Duke's response to RAI 4.3-5 indicates that these transients cause insignificant fatigue and are not counted. The staff notes that NUREG/CR-6260 contains a discussion of these transients for the newer vintage Westinghouse plant and indicates that these transients are not normally counted at PWRs, although some PWRs have reported that the actual cycles of these transients are less than the numbers assumed in the design calculations. However, the NUREG/CR-6260 evaluation indicates the fatigue usage at the charging nozzle for these transients is significant when the reactor water environment is considered. The charging nozzle is one of the locations Duke will assess for fatigue environmental effects. As such, Duke should provide the design stresses and fatigue usage factors associated with the Catawba charging system flow changes.

In its response dated October 2, 2002, the applicant discussed the Catawba charging system flow transients. The applicant indicated that a review of the existing engineering calculations found that the charging and letdown flow change transients cause insignificant fatigue usage.

The staff also reviewed the engineering calculations during a September 18, 2002, meeting with the applicant (summarized by memorandum dated November 18, 2002) and confirmed that the Catawba charging flow transients were determined to cause insignificant fatigue usage. In its July, 9, 2002, submittal, the applicant identified relatively high design basis fatigue usage factors for the RPV outlet nozzle, surge line hot leg nozzle, charging nozzle, and safety injection nozzle for McGuire and Catawba. An assessment by the staff, applying a conservative estimate of the environmental factor to these locations, indicated that the CUFs of these components may exceed 1.0 during the period of extended operation. The applicant stated that it would perform further evaluations of these components, considering environmental effects, prior to the period of extended operation in response to SER open item 4.3-4. This commitment is provided in the revised FSAR supplements for Catawba and McGuire submitted by the applicant in a letter dated October 2, 2002. Therefore, open item 4.3-2 is closed.

<u>Open item 4.3-3.</u> The staff reviewed the Catawba Updated Final Safety Analysis Report (UFSAR), Section 1.7, Regulatory Guides, and Section 5.3.1.4, Special Controls for Ferritic and Austenitic Stainless Steels, and determined that sufficient information was provided in the UFSAR to conclude that underclad cracking was not a concern for Catawba 1 and 2. The staff also reviewed information, submitted by letter from the applicant dated July 9, 2002, to conclude that underclad cracking is not a concern for McGuire 1. However, the staff does not have sufficient information about the McGuire 2 fabrication process to conclude that underclad cracking is not a concern. If the applicant cannot provide conclusive evidence that the fabrication procedure does not result in underclad cracking, then it can furnish an analysis for the license renewal term.

In its response dated October 28, 2002, the applicant stated that Duke had compared the number of design cycles and transients used in the analysis contained in WCAP-15338 with the applicable number of design cycles and transients contained in McGuire Unit 2 design documents, and verifies that WCAP-15338 bounds the number of operating cycles and transients not only for McGuire 2, but also for Catawba Unit 1, whose RV is also fabricated from A508 Class 2 forging segments. In its response to open item 4.3-3, the applicant provided an FSAR supplement summary description to reflect that fatigue analysis in WCAP-15338 for RV underclad cracks in Westinghouse-designed reactors was bounding for the evaluation for RV underclad cracks at McGuire 2. Since the conclusions in WCAP-15338 are bounding and applicable to the evaluation of fatigue-induced crack growth of underclad cracks in the McGuire 2 RV, the staff concludes that the applicant has demonstrated that its analysis for postulated underclad cracks in the McGuire 2 RV remains valid for the extended operating period for McGuire 2, and that the applicant's TLAA for RV underclad cracks at McGuire 2 is acceptable pursuant to 10 CFR 54.21(c)(1)(i). The staff considers SER open item 4.3-3 closed.

<u>New open item 4.3-4.</u> Duke provided a McGuire FSAR supplement for Section 3.9.2 and a Catawba FSAR supplement for Section 3.9.3, which indicate that stress range reduction factors were used in the evaluation of ASME Class 2 and 3 piping systems. Duke also provided a McGuire FSAR supplement for Section 5.2.1 and a Catawba FSAR supplement for Section 3.9.1 to indicate that the Thermal Fatigue Management Program (TFMP) will continue to manage thermal fatigue into the period of extended operation. However, Duke did not describe its commitment to evaluate the effects of the environment on fatigue of reactor coolant system pressure boundary components in the FSAR supplement. Nor did Duke provide a description of its TFMP. A revised FSAR supplement was requested to reflect this information.

In its response dated October 28, 2002, the applicant provided FSAR supplements for Catawba and McGuire. The revised FSAR supplements provided summary descriptions of the TFMP for McGuire and Catawba. The revised FSAR supplements also included the applicant's commitment to perform additional evaluations of the effects of environmental fatigue on the critical locations identified in NUREG/CR-6260 prior to the period of extended operation. Therefore, open item 4.3-4 is closed.

Confirmatory item 2.3.3.26.2-1. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.26-2, the applicant to indicate if piping and nitrogen cylinders associated with a safety-related backup nitrogen control system were within the scope of license renewal. In its response dated April 15, 2002, the applicant confirmed that the Catawba main steam line PORVs are supplied with a nitrogen control system backup to the normal instrument air supply. This backup nitrogen control system consists of valves, tubing, and nitrogen bottles. The applicant stated that the nitrogen bottles are periodically replaced and, therefore, are not subject to an AMR. However, the applicant did not specify the details of the periodic replacement. In electronic correspondence dated July 16, 2002, the applicant stated that a Catawba technical specification surveillance procedure requires nitrogen cylinder replacement if the pressure in either nitrogen cylinder is less than or equal to 2420 psig. Pending the staff's receipt of this information in official correspondence, this item was characterized as confirmatory.

In its response to this confirmatory item, dated October 28, 2002, the applicant formally provided the information that had been furnished in electronic correspondence. The staff finds that the response provides an acceptable basis for excluding these nitrogen bottles from an AMR. Therefore, confirmatory item 2.3.3.26.2-1 is closed.

Confirmatory item 3.6.1-1. The applicant agreed to revise the corrective actions and confirmation process element of the Non-EQ Insulated Cables and Connections Aging Management Program to reflect that the program should consider the potential for moisture in the area of degradation. However, the FSAR supplement needed to be revised to reflect this change to the corrective actions and confirmation process element description.

In its response dated October 2, 2002, the applicant stated that it will add a statement to the Corrective Action & Confirmation Process of the Non-EQ Insulated Cables and Connections Aging Management program summary description contained in Chapter 18 of each station's FSAR supplement to indicate that corrective action should consider the potential for moisture in the area of degradation. The staff found the applicant's response to confirmatory item3.6.1-1 acceptable because the modification to the Non-EQ Insulated Cable and Connections Aging Management Program is reflected in the revised FSAR supplement. Confirmatory item 3.6.1-1 is closed.

Confirmatory item 3.6.2-1. The applicant eliminated the qualifier "significant" from its discussion of exposure to moisture. However, the FSAR supplement needs to be revised to reflect this change in the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program.

In its response dated October 2, 2002, the applicant stated that it will insert the summary description of the revised Inaccessible Non-EQ Medium Voltage Cables AMP (as provided in Duke letters dated July 9, 2002, Attachment 1, pages 89-91, and November 5, 2002) in each station's FSAR supplement in place of the program description previously provided. The staff found the applicant's response to confirmatory item 3.6.2-1 acceptable because the change to the program provided by the applicant will be reflected in the FSAR supplement.

<u>Confirmatory item 4.4-1.</u> To address Generic Safety Issue (GSI) 168, the applicant submitted, in a letter dated July 9, 2002, a technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging. However, the staff requested that the applicant also indicate that it will monitor updates to NUREG-0933, "A Prioritization of Generic Safety Issues," for revisions to GSI-168 during the review of its application, or that it will supplement its license renewal application if the issues associated with GSI-168 become defined such that providing the options or pursuing one of the other approaches described in the SOC becomes feasible.

In its response dated October 2, 2002, the applicant stated that, if the staff were to issue a generic communication that defines the issues associated with GSI-168 such that providing the options or pursuing one of the other approaches described in the SOC to 10 CFR 54 (FR Vol.60, No.88, May 8,1995) becomes feasible, then Duke would supplement its license renewal application. However, the applicant also specified that the staff generic communication should be issued prior to November 1, 2002, in order for Duke to evaluate its contents, prepare a response as a current licensing basis change, if any is required, and provide a supplement to the application (if necessary) in sufficient time for the staff to complete its review prior to the scheduled issuance of the SER for license renewal on January 6, 2003. The resolution to GSI-168 was not issued by the staff prior to November 1, 2002; thus, the applicant's alternative commitment is their original commitment that was stated above in their June 17, 2002, response to GSI-168. Pursuant to the requirements of Part 50, the staff will evaluate the applicant's compliance to the resolution of GSI-168 after its issuance and prior to the extended period of license renewal as part of 10 CFR 50.49 time-limited aging analyses. Resolution of GSI-168 pursuant with Part 50 meets the requirement of 10 CFR 54.21(c)(1)(iii) and is therefore considered acceptable. Confirmatory item 4.4-1 is considered closed.

# 2. SCOPING AND SCREENING

## 2.1 Scoping and Screening Methodology

### 2.1.1 Introduction

Title 10 of the *Code of Federal Regulations*, Part 54 (10 CFR Part 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants,” Section 54.21, “Contents of Application - Technical Information,” requires that each application for license renewal contain an integrated plant assessment IPA. Furthermore, the IPA must list and identify those structure and components (SCs) that are subject to an aging management review (AMR) from the systems, structures, and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4.

In Section 2.1, “Scoping and Screening Methodology,” of the Catawba and McGuire license renewal application (LRA), the applicant described the scoping and screening methodology used to identify SSCs at Catawba and McGuire that are within the scope of license renewal, and SCs that are subject to an AMR. The staff reviewed the applicant’s scoping and screening methodology to determine if it meets the scoping requirements set forth in 10 CFR 54.4(a) and the screening requirements set forth in 10 CFR 54.21.

In developing the scoping and screening methodology for the Catawba and McGuire LRA, the applicant considered the requirements of the license renewal rule, the Statements of Consideration (SOCs) for the rule, and the guidance provided by the Nuclear Energy Institute (NEI), “Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,” Revision 2, August 2000 (NEI 95-10). In addition, the applicant also considered the U.S. Nuclear Regulatory Commission (NRC) staff’s correspondence with other applicants and with the NEI in the development of this methodology.

### 2.1.2 Technical Information in the Application

In Chapters 2.0 and 3.0 of the LRA, the applicant provides the technical information required by 10 CFR 54.21(a). In Section 2.1, “Scoping and Screening Methodology,” of the LRA, the applicant described the process used to identify the SSCs that meet the license renewal scoping criteria under 10 CFR 54.4(a), as well as the process used to identify the SCs that are subject to an AMR as required by 10 CFR 54.21(a)(1).

Additionally, LRA Section 2.2, “Plant Level Scoping Results;” Section 2.3, “System Scoping and Screening Results: Mechanical;” Section 2.4, “Scoping and Screening Results: Structures;” and Section 2.5, “Screening Results: Electrical and Instrumentation and Controls,” describe in detail the process that the applicant uses to identify the SCs that are subject to an AMR.

Chapter 3 of the LRA, “Aging Management Review Results,” contains the following information—Section 3.1, “Aging Management of Reactor Vessel, Internals and Reactor Coolant System;” Section 3.2, “Aging Management of Engineered Safety Features;” Section 3.3, “Aging Management of Auxiliary Systems;” Section 3.4, “Aging management of Steam and Power Conversion Systems;” Section 3.5, “Aging Management of Containment, Structures, and Component Supports;” Section 3.6, “Aging Management of Electrical and

Instrumentation and Controls." Chapter 4 of the LRA, "Time-Limited Aging Analyses," (TLAAs) contains the applicant's evaluation of time-limited aging analyses.

*2.1.2.1 Scoping Methodology*

Section 2.1.1 of the LRA, "Scoping Methodology," discussed the scoping methodology as it related to the safety-related criteria in accordance with 10 CFR 54.4(a)(1), non-safety-related criteria in accordance with 10 CFR 54.4(a)(2), and the scoping criteria in accordance with 10 CFR 54.4(a)(3) for regulated events.

2.1.2.1.1 Safety-Related Systems, Structures, and Components

The LRA stated that the SSCs within the scope of license renewal include safety-related SSCs, which are those relied upon to remain functional during and following design basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions—

> 1) the integrity of the reactor coolant pressure boundary, 2) the capability to shut down the reactor and maintain it in a safe shutdown condition, or 3) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable.

The applicant used the guidance contained in Regulatory Guide (RG) 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants," and RG 1.29, "Seismic Design Classification," to establish those mechanical systems which met the scoping criteria of 10 CFR 54.4(a)(1). Piping Classes A, B, and C were designated as safety-related and subject to the requirements of 10 CFR 54.4(a)(1).

The Commission's regulations at *10 Code of Federal Regulations* Part 100, Appendix A, "Seismic and Geological Siting Criteria for Nuclear Power Plants," require that certain structures, systems, and components must remain functional during a safe-shutdown earthquake. The applicant determined the intended functions met the intent of the scoping criteria in 10 CFR 54.4(a)(1). The specific structures required to meet these criteria are identified in RG 1.29 as Seismic Category I and were considered within the scope of license renewal. The classification of each structure had been previously identified and documented in the Updated Final Safety Analysis Report (UFSAR).

The scoping criteria were not applied globally to all electrical systems and components. The scoping criteria were applied only to specific electrical systems in order to demonstrate that they were not within the scope of license renewal. The majority of electrical systems and components were included within the scope of license renewal by default without a detailed scoping evaluation having been performed.

2.1.2.1.2 Non-Safety-Related Systems, Structures, and Components

Certain non-safety-related piping and components had been designated as Duke System Class F. This pipe classification applied to piping and components whose pressure boundary loss could adversely affect safety-related systems and components due to physical interactions. All Duke Class F piping and components met the criteria of 10 CFR 54.4(a)(2) and were included within the scope of license renewal. Non-safety-related structures whose failure could affect the intended function of safety-related SSCs had been previously designated as Seismic Category II in accordance with RG 1.29. The applicant determined that these structures met the criteria of 10 CFR 54.4(a)(2) and were within the scope of license renewal. Structures not identified as Category I or II had been designated as Category III. Failure of a Category III structure would not have an impact on the integrity of Category I or II structures. Category III structures were not included within the scope unless they met the criteria of 10 CFR 54.4(a)(3). Specific non-safety-related electrical systems and components were reviewed against the scoping criteria of 10 CFR 54.4(a)(2).

2.1.2.1.3 Regulated Events

The systems, structures, and components required to maintain compliance with 10 CFR 54.4(a)(3) were determined through a review of the UFSAR, safety evaluation reports, licensing correspondence files, and other appropriate design documents.

*2.1.2.2 Screening Methodology*

Following the determination of SSCs within the scope of license renewal, the applicant implemented a process for determining which SCs, among those SSCs that were determined to be within the scope of renewal, would be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). Section 2.1.2 of the LRA, "Screening Methodology," discussed the screening activities as they related to the SSCs that are within the scope of license renewal. The specific screening activities for the various engineering disciplines were further described in the LRA in Section 2.1.2.1 for mechanical components, Section 2.1.2.2 for structural components, and Section 2.1.2.3 for electrical components.

2.1.2.2.1 Screening Methodology for Mechanical Components

Following identification of the SSCs within the scope of license renewal, the applicant performed the following screening review to determine which mechanical components would be subject to an AMR.

The mechanical components within the scope of 10 CFR Part 54 were reviewed to determine those components subject to an AMR in accordance with 10 CFR 54.21(a)(1). An AMR of a mechanical component is required if the component performs an intended function without moving parts or without a change in configuration or properties (i.e., passive) and if it is not subject to replacement on the basis of a qualified life or specified time period (i.e., long-lived).

The screening methodology involved three steps—

- establishment of the license renewal evaluation boundaries
- identification of the intended function(s) of each component
- identification of mechanical components subject to an AMR

The applicant established the evaluation boundaries as either safety-related, non-safety-related, or regulated event boundaries. Piping Classes A, B, and C were designated as safety-related. The intended functions were determined on the basis of the system function, which had been the basis for including the system within the scope of license renewal, and the component function, which is required to enable the system to perform its intended function. Duke Class F piping was designated as non-safety-related piping and components whose pressure boundary loss could adversely affect safety-related systems and components due to physical interactions. All Duke Class F piping and components met the criteria of 10 CFR 54.4(a)(2). Identification of the components subject to an AMR was performed using plant system flow diagrams (FDs), equipment databases, and the guidance of NEI 95-10, Appendix B.

2.1.2.2.2 Screening Methodology for Structural Components

Following identification of the structural components within the scope of license renewal, the applicant performed the following screening review to determine which structural components would be subject to an AMR.

The intended functions of the structural components were determined through a review of the UFSAR, engineering specifications, regulated event documentation, and the commitments made in response to design basis events. Structural component functions were reviewed to determine whether the structural component (1) supported the intended function of the structure, or (2) had a unique function not required to support the intended function of the structure. In addition, structural components were reviewed to determine whether the component was required to physically support non-safety-related components to prevent physical interaction with safety-related components in order to meet the requirements of 10 CFR 54.4(a)(2).

The structural components within the scope of 10 CFR Part 54 were reviewed to determine those components subject to an AMR in accordance with 10 CFR 54.21(a)(1). An AMR of a structural component is required if the component performs an intended function without moving parts or without a change in configuration or properties (i.e., passive) and if it is not subject to replacement on the basis of a qualified life or specified time period (i.e., long-lived).

The screening methodology involved three steps—

- generation of a list of structural components types
- identification of the intended functions of each component
- identification of structural components subject to an AMR

The applicant developed a list of structural components using the guidance of NUMARC 90-01, NUMARC 90-06, and Appendix B of NEI 95-10. Additional components were added on the basis of commitments made for compliance with regulated events, including fire protection (FP), environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transients without scram, and station blackout (SBO). In addition, the applicant reviewed other specific documents to determine any other structural components not previously identified.

2.1.2.2.3 Screening Methodology for Electrical Components

After identifying the SSCs within the scope of license renewal, the applicant also performed the following screening review to determine which electrical components would be subject to an AMR. As part of this effort, the applicant relied on the requirements set forth in 10 CFR 54.21(a)(1)(i), as supplemented by industry guidance in NEI 95-10, to develop a commodity evaluation approach on the basis of a plant level evaluation of electrical equipment. The applicant reviewed the component to determine whether the component was passive and long-lived.

The passive components were identified as the following items—

- electrical portions of electrical and Instrumentation and Control penetration assemblies
- high-voltage insulators
- insulated cables and connections
- phase bus
- switchyard bus
- transmission conductors
- uninsulated ground conductors

The application stated that all other electrical and I&C components were active and were not subject to an AMR.

Other electrical and I&C components were in scope only because they performed a passive pressure boundary function (elements, resistance temperature detectors (RTDs), sensors, thermocouples, transducers, and heaters). These components were electrically active, but were subject to an AMR only for the pressure boundary function.

Electrical components that were included in the applicants' environmental qualification program in accordance with 10 CFR 50.49 are replaced on the basis of a qualified life and therefore were not subject to an AMR. These components included certain insulated cables and connections, and all electrical and I&C penetration assemblies. No other electrical components were screened out on the basis of the long-lived screening criterion. The remainder of the integrated plant assessment involved only non-environmentally-qualified electrical and I&C components.

### 2.1.3 Staff Evaluation

From October 15 through 18, 2001, the staff performed an audit of the applicant's license renewal scoping and screening methodology developed to support the license renewal process and documented in the LRA.

The focus of the staff's audit was to evaluate the applicant's administrative control documents governing the implementation of its LRA scoping and screening methodology, and to review selected design documents, including scoping and screening result reports, which provided the technical basis for various plant systems, structures, and components evaluated as part of the LRA scoping and screening methodology.

### *2.1.3.1 Evaluation of the Methodology for Identifying Systems, Structures, and Components Within the Scope of License Renewal*

<u>Definition of Safety-Related Structures, Systems, and Components</u>

In LRA Section 2.1.1.1, “Safety-Related Structures, Systems, and Components,” the applicant appropriately stated that plant systems, structures, and components within the scope of license renewal that satisfy the scoping criteria in 10 CFR 54.4(a)(1) are

> (1) safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions—
>
>> (i) the integrity of the reactor coolant pressure boundary;
>>
>> (ii) the capability to shut down the reactor and maintain it in a safe shutdown condition; or
>>
>> (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or § 100.11 of this chapter, as applicable.

However, during the staff’s scoping and screening audit, conducted from October 15 to 19, 2001, the staff noted that Section 3.0, “Scoping Methodology,” of both Specifications CNS-1274.00-00-0002, “Catawba Systems and Structures Scoping for License Renewal,” and MCS-1274.00-00-0002, “McGuire Systems and Structures Scoping for License Renewal,” cited superseded regulatory text in establishing the scoping criteria to be used in identifying Catawba and McGuire structures, systems, and components in accordance with 10 CFR 54.4(a)(1) requirements. In particular, these specifications cited the following criteria in reference to 10 CFR 54.4(a)(1) scoping requirements—

> (a) Plant systems, structures, and components within the scope of this part are
>
> (1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design bases events (as defined in 10 CFR 50.49(b)(1)) to ensure the following functions—
>
>> (i) The integrity of the reactor coolant pressure boundary,
>>
>> (ii) The capability to shut down the reactor and maintain it in a safe shutdown condition, or
>>
>> (iii) The capability to prevent or mitigate the consequences of accidents that could result in potential off-site exposure comparable to the 10 CFR Part 100 guidelines.

By letter dated January 17, 2002, the staff requested the applicant, in RAI (request for additional information) 2.1-1, address the impact, if any, of not having explicitly considered in its scoping methodology for Catawba and McGuire those structures, systems, and components that are relied upon to ensure “the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, as applicable,” consistent with the current licensing basis CLB.

In its response dated March 1, 2002, the applicant indicated that it had reviewed the scoping criteria in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), and 10 CFR 100.11 as currently written in 10 CFR 54.4(a)(1)(iii) and determined that there was no impact on the scoping review it had described in its LRA. The applicant stated that for 10 CFR 50.34(a)(1), only 10 CFR 50.34(a)(1)(i) was applicable and referred to 10 CFR Part 100 for specific site evaluation factors. Section 100.11 of title 10 of the *Code of Federal Regulations* was applicable and was used in the scoping process. The applicant further indicated that 10 CFR 50.34(a)(1)(ii) was only applicable to 10 CFR Part 50 applications filed on or after January 10, 1997, and was therefore not applicable to Catawba and McGuire. In addition, the applicant stated that 10 CFR 50.67(b)(2) was not applicable because license amendments had not been made at either station to allow use of the revised accident source term. The applicant stated that the scoping methodology specifications would be revised to incorporate the current criteria of 10 CFR 54.4(a)(1)(iii) by June 30, 2002. On the basis of its review of the information provided by the applicant, the staff concluded that the applicant had documented that only a portion of the criteria was applicable to the applicant's plants and that the applicable portion had been incorporated into the license renewal activities. Therefore, the staff concluded that the response to the issue raised met the applicable regulations and was acceptable.

<u>Definition of Non-safety-related Structures, Systems, and Components</u>

Non-safety-related SSCs that are within the scope of license renewal are defined in 10 CFR 54.4(a)(2)—

> All non-safety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1) (i), (ii), or (iii) of this section.

In LRA Section 2.1.1.2, "Nonsafety-Related Systems, Structures and Components," the applicant provides its methodologies for identifying mechanical SSCs and electrical systems and components that satisfy the scoping criterion in 10 CFR 54.4(a)(2).

On the basis of its review of information provided by the applicant, the staff concluded that the applicant had adequately documented the 10 CFR 54.4(a)(2) criteria and had incorporated the information into the license renewal activities with the exception of one issue. The staff identified an issue concerning mechanical scoping as RAI 2.1-2, which is discussed in Section 2.1.3.1.1, "Mechanical Scoping Methodology." The staff concluded that the applicant's response to RAI 2.1-2 described a methodology that met the applicable regulations and, therefore, was acceptable.

<u>Regulated Events</u>

The staff determined, as stated in the LRA, that for regulated events, the systems, structures, and components required to maintain compliance with 10 CFR 54.4(a)(3) were determined through a review of the UFSAR, safety evaluation reports (SERs), licensing correspondence files, and other appropriate design documents and were included in scope on the basis of the requirements of 10 CFR 54.4(a)(3). The staff reviewed examples of documents that used this method and did not identify any discrepancies between the methodology documented and the implementation results.

2.1.3.1.1 Mechanical Scoping Methodology

The applicant based the scoping activities on several sets of information. The applicant had developed a set of FDs in 1971 using all design basis information and the FDs had been subsequently maintained current to date. Design basis documents (DBDs) had been prepared during design basis reconstitution (performed prior to license renewal activities). The DBDs were developed on the basis of the FDs, or compared to the FDs with the FDs being the reference standard. The FDs and DBDs were used to provide the basis for those mechanical systems meeting the criteria of 10 CFR 54.4(a)(1) and (a)(2). In addition, the appendices in Nuclear System Directive (NSD) 307, "Quality Standards Manual," were used, after the FDs were reviewed, to identify any systems which had not been previously identified.

The applicant used the guidance contained in RG 1.26 and RG 1.29 to establish those mechanical systems which met the scoping criteria of 10 CFR 54.4(a)(1). Piping Classes A, B, and C were designated as safety-related and subject to requirements of 10 CFR 54.4(a)(1). The applicant identified the safety-related mechanical boundaries using the FDs.

Certain non-safety-related piping and components had been designated as Duke Class F piping. This was applied to piping and components whose pressure boundary loss could adversely affect safety-related systems and components due to physical interactions. All Duke Class F piping and components met the criteria of 10 CFR 54.4(a)(2) and were included within the scope of license renewal. The applicant identified the Duke Class F boundaries using the FDs and all non-safety-related functions using the DBDs, UFSAR, calculations, specifications, and licensing correspondence. In addition, the applicant used the DBDs, UFSAR, calculations, specifications, and licensing correspondence to identify all mechanical components required to meet 10 CFR 54.4(a)(3).

The staff noted that piping Classes E, G, and H, which were seismically supported so as not to affect safety-related components, were not included in the scope of license renewal (the piping hangers were) but were possibly in the proximity of safety-related components. The staff discussed the applicant's approach to identifying non-safety-related components that could affect safety-related components with the applicant and, by letter dated January 17, 2002, requested, in RAI 2.1-2, specific clarification regarding the applicant's approach to scoping and screening non-safety-related SSCs in accordance with 10 CFR 54.4(a)(2).

In its response dated April 15, 2002, the applicant indicated that the initial design of the modern-vintage plants had incorporated detailed consideration of both fluid and spatial interactions of non-safety-related sources on safety-related equipment, was continued through the modification process, and provided the basis for meeting the scoping requirements of 10 CFR 54.4(a)(2). The analyses used had been performed for every area of the plants that housed safety-related equipment and included both spatial and fluid interaction. This response was further clarified during a May 24, 2002, telephone call, which was documented by memorandum issued June 7, 2002.

The applicant stated that all non-safety-related, high-energy piping in proximity of safety-related equipment was designated Duke Class F and was within the scope of license renewal. Piping Classes E, G, and H were moderate-energy pipe. The moderate-energy pipe had been analyzed on the basis of a postulated through-wall crack on pipes greater than 1-inch nominal pipe size. The spray was assumed to impact equipment up to 30 feet in all directions from the spray source. When potential impact had been identified, piping was rerouted, equipment was relocated, or the equipment was qualified for the effects of spray, temperature, and wetting.

Piping less than 1-inch nominal size was physically located in parallel runs with piping of various sizes. The smaller pipes were proximal to larger pipes that were evaluated for spray effects and such evaluations bounded the potential spray effects from the smaller piping. The applicant indicated that the potential of small-piping runs proximal to safety-related equipment, but not proximal to larger pipes, had been reviewed, and that this did not exist in areas containing safety-related equipment. The applicant's treatment of piping less than 1-inch nominal size also was explained during an NRC scoping and screening inspection, as documented in Inspection Reports 50-369/02-05, 50-370/02-05, 50-413/02-05, and 50-414/02-05, dated May 6, 2002, and during a May 24, 2002, telephone call, which was documented by memorandum dated June 7, 2002. Based upon the information presented during the conference calls and documented in the NRC inspection report, the staff concluded that the treatment of this class of very small pipe was acceptable.

The staff concluded that the applicant's approach to identifying non-safety-related SCs that could potentially affect safety-related SCs (e.g., designating pipe in high-energy systems and seismic hangers supporting pipe in moderate-energy pipe systems as within scope), and the rationale for excluding the less than 1-inch pipe due to its potential impact being bounded by the larger, proximal pipes, met the requirements of 10 CFR 54.4(a)(2) and was acceptable. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

For non-safety-related equipment (other than piping systems) in proximity to safety-related systems, the applicant indicated that it had taken the mitigative approach and determined that the seismic supports and restraints would prevent physical interaction and that the seismic supports and restraints were included within the scope of license renewal. The staff concluded that the inclusion of the seismic supports was adequate to restrain non-fluid-bearing equipment, since the method of potential impact was physical contact. On the basis of its review of the information, the staff concludes that the response to RAI 2.1-2 was acceptable because the applicant had demonstrated that it performed its scoping review in accordance with 10 CFR 54.4(a)(2).

2.1.3.1.2 Structural Scoping Methodology

As stated in Section 2.1.1.1.2 of the LRA, "Safety-Related Structures," the staff determined that all structures at both the McGuire and Catawba Nuclear Stations were classified according to their design function. Appendix A to 10 CFR Part 100, "Seismic and Geological Citing Criteria for Nuclear Power Plants," requires that all nuclear power plants be designed so that, if a safe-shutdown earthquake occurs, certain SSCs remain functional.

The applicant determined that the three functions meet the intent of those specified in the scoping criteria in 10 CFR 54.4(a)(1). The specific structures that are required to ensure these functions are satisfactorily implemented are identified in RG 1.29 as Seismic Category I structures. All safety-related structures were designated as Seismic Category I and are within the scope of license renewal. The classification of each structure had been previously determined and documented in the McGuire UFSAR and Catawba UFSAR. Category I structures had been identified through a review of the plant UFSAR.

Section 2.1.1.2.2 of the LRA, “Non-safety-Related Structures,” stated that structures whose continued function is not required, but whose failure could impact the function of safety-related SSCs or could injure control room occupants are designated as Seismic Category II in accordance with RG 1.29 Position C. The structures are classified as non-safety-related, but are designed to prevent detrimental effects to safety-related SSCs. Category II structures meet the intent of 10 CFR 54.4(a)(2) and were determined to be within the scope of license renewal.

Structures at McGuire and Catawba that were not identified as either Category I or II were classified as Category III structures. Category III structures were those whose functions were not related to nuclear safety and whose collapse under earthquake loading would not impair the integrity of seismic Category I or II items. Category III structures were not within the scope of license renewal unless they were determined to meet the criteria of 10 CFR 54.4(a)(3).

The classification of each structure had been previously determined and documented in the McGuire UFSAR and Catawba UFSAR. Category II structures were identified through a review of the plant UFSAR. The staff reviewed the classification of structure types, and discussed the process with the applicant, and the applicant provided a demonstration of the scoping process, including examples of application of the process and the resulting documentation. On the basis of this review, the staff did not identify any discrepancies between the methodology documented and the implementation results.

2.1.3.1.3 Electrical Scoping Methodology

The staff reviewed Sections 2.1.1.1.3, 2.1.2.3, and 2.5 of the LRA to determine the adequacy of the method that the applicant had used to identify the electrical components within the scope of license renewal in accordance with 10 CFR 54.4. During the scoping and screening methodology audit, the staff met with applicant representatives to discuss the applicant’s methodology for electrical scoping and to review design basis documents that support the LRA.

The staff reviewed document DPS (MCS, CNS) 1274.00-00-0006, “Electrical Component Integrated Plant Assessment and Evaluation of Time-Limited Aging Analysis for License Renewal,” Rev. 01, June 12, 2001. This document applied to both McGuire and Catawba plants. The purpose of the document was to describe the scoping and screening process used by the applicant to identify electrical components that were subject to an AMR and to present the results of that process.

The scoping criteria were not applied globally to all electrical systems and components. The majority of electrical systems and components were included within the scope of license renewal by default without a detailed scoping evaluation having been performed. The scoping criteria were applied only to specific electrical systems in order to demonstrate that they were not within the scope of license renewal. The staff finds this approach conservative and acceptable because it would identify more electrical components subject to an AMR than are required by the rule.

The staff reviewed the document MCS-1274.00-00-0002, “McGuire Systems and Structures Scoping for License Renewal,” Rev. 05, September 12, 2001, and a nearly identical document for Catawba. LRA Section 3.3 described the applicant’s electrical system and component scoping process. The applicant assumed that all electrical components were within the scope of license renewal unless a specific scoping evaluation was performed that demonstrated they were not within the scope of license renewal. The scoping process described by the applicant was used to determine that an electrical component or commodity group was not in scope for license renewal. In order to demonstrate that an electrical system, component, or commodity group was not within the scope of license renewal, a scoping evaluation was performed. The evaluation involved describing the system, component, or commodity group functions and then evaluating these functions against the scoping criteria of 10 CFR 54.4(a).

The staff reviewed several sections of the LRA which evaluated specific systems and components for application of the methodology (1) Section 4.3.1 (phase bus in the switchyard systems EA, EB, and ES of both plants) and (2) Section 4.3.2 (unit main power system EPA) and (3) Section 4.3.3 (6.9 kV normal auxiliary power system EPB). The applicant concluded that the only electrical components in the scope of license renewal and subject to an AMR were non-EQ insulated cables and connections. The staff reviewed the classification of electrical components and discussed the process with the applicant. The applicant provided a demonstration of the scoping process, including examples of how the process was applied and the resulting documentation. On the basis of this review, the staff did not identify any discrepancies between the methodology documented and the implementation results.

The staff considered the original information supplied in the LRA and additional information supplied by the applicant during the audit and subsequent responses to staff RAIs, particularly RAIs 2.5-1 and 2.5-2 (discussed in detail in Section 2.5.2 of this SER). This information included identification and inclusion in scope of the SSCs meeting the requirements of 10 CFR Part 54.4(a)(1) identification and inclusion in scope of the SSCs meeting the requirements of 10 CFR Part 54.4(a)(2) and identification and inclusion in scope of the SSCs meeting the requirements of 10 CFR Part 54.4(a)(3). On the basis of this information, the staff concludes that the method developed and implemented by the applicant is sufficient to ensure that all applicable SSCs are considered in scope of license renewal.

#### *2.1.3.2 Evaluation of the Methodology for Identifying Structures and Components Subject to an Aging Management Review*

##### 2.1.3.2.1 Mechanical Component Screening Methodology

The mechanical components within the scope of 10 CFR Part 54 were reviewed to determine those components subject to an AMR in accordance with 10 CFR 54.21(a)(1). An AMR of a mechanical component is required if the component performs an intended function without moving parts or without a change in configuration or properties (i.e., passive) and if it is not subject to replacement on the basis of a qualified life or specified time period (i.e., long-lived).

The screening methodology involved three steps—

1. establishment of the license renewal evaluation boundaries
2. identification of the intended function(s) of each component
3. identification of mechanical components subject to an AMR

The staff determined, as stated in the LRA, that the applicant had established the evaluation boundaries as either safety-related, non-safety-related, or regulated event boundaries. The applicant's Piping Classes A, B, and C were designated as safety-related. The applicant's Class F piping was designated as non-safety-related piping and components whose pressure boundary loss could adversely affect safety-related systems and components due to physical interactions.  All Class F piping and components met the criteria of 10 CFR 54.4(a)(2).  The intended functions were determined based on the system function, which is the basis for including the system within the scope of license renewal, and the component function, which is that which is required to enable the system to perform its intended function.  Identification of the components subject to an AMR was performed using plant system flow diagrams, equipment databases, and the guidance of NEI 95-10, Appendix B.

The staff reviewed the “Feedwater System Component Screening and Aging Management Review for License Renewal” and the “Safety Injection System Component Screening and Aging Management Review for License Renewal” as examples to determine how the methodology had been applied.  The applicant determined that the evaluation boundaries for the feedwater system had extended onto the FD of the auxiliary feedwater (AFW) system.  For the purposes of the feedwater system screening, the extended portions had been included in the feedwater system specification for completeness.

Again, using the feedwater system and safety injection system (SIS) as examples, the applicant demonstrated how it used scoping results to indicate evaluation boundaries on FDs.  The applicant demonstrated how it had evaluated components to determine if they were subject to an AMR.  Specifically, the applicant described how it (1) identified the components’ intended functions (using DBDs and the UFSAR) (2) determined the materials of construction (using FDs and vendor drawings) and (3) identified the internal and external environments (using FDs and DBDs).  The audit team did not identify any inconsistencies between the methodology described in the LRA and implementing procedures, and the process demonstrated by the applicant.

Some components that are common to many systems were evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as replace on condition commodities.  Examples of these commodities include filter media, such as paper filters, charcoal filters, and resins.  On page 2.1-21 of the LRA, the applicant stated that periodic testing and inspection programs are in place to monitor filter performance, degradation of which may be indicated by an increase in differential pressure or a change in absorption efficiency.  The filter mediums are replaced as conditions warrant and, therefore, are not subject to an AMR.  As stated in the SRP-LR, system filters, fire extinguishers, fire hoses, and air packs may be excluded, on a plant-specific basis, from an AMR under 10 CFR 54.21(a)(1)(ii) in that they are replaced on condition; however, the application should identify the standards that are relied on for replacement as part of the methodology description.  Since the applicant indicated that periodic testing and inspection programs are in place to monitor filter performance, degradation of which may be indicated by an increase in differential pressure or a change in absorption efficiency, the staff finds the applicant’s treatment of these consumables acceptable because it conforms to 10 CFR 54.21(a)(1)(ii).

#### 2.1.3.2.2 Structural Screening Methodology

The staff determined that Section 2.1.2.2, “Screening Methodology for Structural Components,” of the LRA provided the methodology for determining the structural components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) of the license renewal rule. The component screening methodology for McGuire and Catawba involved the following steps—

1. generation of a list of structural component types
2. identification of the intended function(s) of each structural component
3. identification of structural components subject to AMR

Consistent with the guidance provided in NEI 95-10, the structures and structural components within the scope of license renewal are long-lived and passive; therefore, they require an AMR. The tables contained in Section 3.5 of the LRA list the structural components that are subject to AMR along with their intended functions. The staff reviewed the list of structural component types, reviewed the intended functions for several examples of structures and structural components, and reviewed the process of identification of structural components subject to an AMR. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

2.1.3.2.3 Electrical Screening Methodology

The staff reviewed Sections 2.1.1.1.3, 2.1.2.3, and 2.5 of the LRA to determine the adequacy of the method used by the applicant to identify the electrical components subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1). The staff met with applicant representatives to discuss their methodology for electrical screening and to review basis documents that support the LRA.

The staff reviewed document DPS (MCS, CNS) 1274.00-00-0006, "Electrical Component Integrated Plant Assessment and Evaluation of Time-Limited Aging Analysis for License Renewal," Rev. 01, June 12, 2001. This document applied to both McGuire and Catawba Nuclear Stations. The purpose of the document was to describe the scoping and screening process used by the applicant to identify electrical components that were subject to an AMR and to present the results of that process.

The applicant began the process with a list of electrical commodities, which is the generic list from Appendix B of NEI 95-10. Next, the applicant applied passive screening that eliminated from the list all commodities that were active rather than passive (i.e.,components that performed an intended function without moving parts or without a change in configuration). The remaining seven passive commodities were insulated cables and connections, uninsulated ground connectors, transmission conductors, phase bus, switchyard bus, electrical portions of electrical penetrations, and high-voltage insulators.

The applicant applied long-lived screening criteria to the remaining passive components. Components that were to be replaced on the basis of a qualified life were removed from any further consideration for an AMR. The applicant concluded that all electrical components included in the applicant's environmental qualification program that were short-lived were screened out. The resulting list includes only non-EQ electrical components.

The staff reviewed several sections of the LRA which evaluated specific systems and components for application of the methodology. These sections are (1) Section 4.3.1 (phase bus in the switchyard systems EA, EB, and ES of both plants), (2) Section 4.3.2 (unit main power system EPA), and (3) Section 4.3.3 (6.9 kV normal auxiliary power system EPB). The applicant had concluded that the only electrical components in the scope of license renewal and subject to an AMR were non-EQ insulated cables and connections. The audit team did not identify any discrepancies between the methodology documented and the implementation results.

The staff reviewed information related to the methods used for screening of mechanical, structural, and electrical SCs. On the basis of the its review of information provided in the LRA, and additional information supplied by the applicant during the audit, the staff concludes that the applicant's methodology for identifying structures and components subject to an AMR meets the requirements of 10 CFR 54.21.

### 2.1.4 Conclusions

The staff review of the information presented in Section 2.1 of the LRA, the supporting information in the plants' UFSARs, the information presented during the scoping and screening audit and inspection, and the applicant's responses to the staff's RAIs, as discussed above, formed the basis of the staff's safety determination. The staff verified that the applicant's scoping and screening methodology, including its supplemental 10 CFR 54.4(a)(2) review, was consistent with the requirements of the license renewal rule and the staff's position on the treatment of non-safety-related SSCs. The staff concludes that there is reasonable assurance that the scoping and screening methodology used by the applicant to identify SSCs within the scope of the rule and SCs that are subject to an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21.

## 2.2 Plant Level Scoping Results

### 2.2.1 Introduction

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant identified the SSCs that are within the scope of license renewal and the systems and structures (SSs) that are not within the scope of license renewal. The applicant provided the results of its scoping review in Section 2.2 of the LRA, "Plant Level Scoping Results." The staff reviewed Section 2.2 of the LRA to determine whether there is reasonable assurance that the applicant has properly identified all plant level SSCs that are relied upon to mitigate design basis events as required by 10 CFR 54.4(a)(1) or whose failure could prevent mitigation of design basis events as required by 10 CFR 54.4(a)(2), as well as the SSCs relied on in safety analyses or plant evaluations to perform a function that is required by one of the regulations referenced in 10 CFR 54.4(a)(3).

### 2.2.2 Technical Information in the Application

#### *2.2.2.1 Systems, Structures, and Components Within the Scope of License Renewal*

The SSCs that the applicant has determined to be within the scope of license renewal are presented in Table 2.2-1, "McGuire Systems and Structures within the Scope of License Renewal," and Table 2.2-2, "Catawba Systems and Structures within the Scope of License Renewal," of the LRA. The mechanical systems listed in Tables 2.2-1 and 2.2-2 are described in Section 2.3 of the LRA. The structures listed in Tables 2.2-1 and 2.2-2 are described in Section 2.4 of the LRA. The electrical and instrumentation and control (I&C) components are described in Section 2.5. In regard to electrical systems, the applicant stated on pages 2.2-6 and 2.2-10 that, except for the switchyard systems, unit main power system, nonsegregated-phase bus in the 6.9 kV normal auxiliary power system, and uninsulated ground conductors, all other electrical, instrumentation, and control systems and components were found to be within the scope of license renewal.

*2.2.2.2 Systems and Structures Not Within the Scope of License Renewal*

The SSs that the applicant has determined not to be within the scope of license renewal are presented in Table 2.2-3, “McGuire Systems and Structures Not Within the Scope of License Renewal,” and Table 2.2-4, “Catawba Systems and Structures Not Within the Scope of License Renewal,” of the LRA. In regard to electrical systems and components, the applicant stated on pages 2.2-13 and 2.2-16 that the switchyard systems, unit main power system, nonsegregated-phase bus in the 6.9 kV normal auxiliary power system, and uninsulated ground conductors were found not to be within the scope of license renewal.

### 2.2.3 Staff Evaluation

The staff reviewed Section 2.2, and specifically Tables 2.2-1, 2.2-2, 2.2-3, and 2.2-4 of the LRA, to determine whether there is reasonable assurance that the applicant had properly identified all plant level SSCs that are within the scope of license renewal as required by 10 CFR 54.4. The staff focused its review on verifying that the implementation of the applicant’s methodology discussed in Section 2.1.1 of this SER did not result in the omission of SSCs from the scope of license renewal.

The staff used the UFSARs for both units of McGuire and Catawba in performing its review. Pursuant to 10 CFR 50.34(b), the UFSAR contains a description and analysis of the SSCs of the facility, with emphasis upon performance requirements; the bases, with technical justification, upon which such requirements have been established; and the evaluations required to show that safety functions will be accomplished. The UFSAR is required to be updated periodically pursuant to 10 CFR 50.71(e). Thus, the UFSAR contains updated plant-specific licensing basis information regarding the SSCs and their functions.

The staff sampled the contents of the UFSAR, based on the listing of the SSs in Tables 2.2-3 and 2.2-4 of the LRA, to identify whether there are SSs that may have intended functions in accordance with the scoping requirements of 10 CFR 54.4 but were listed by the applicant as not within the scope of license renewal.

During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 2.2.1-1, that the applicant provide the basis for listing the control rod drive ventilation system and the incore instrumentation area ventilation system on Table 2.2-3 as not within the scope of license renewal. The staff referred to Table 8-1 of McGuire UFSAR that lists both the control rod drive ventilation fans and the incore instrumentation room air handling units as receiving power from the 4160 volt essential auxiliary power system during a blackout or accident condition. In its response dated March 1, 2002, the applicant stated that the control rod drive ventilation system and the incore instrumentation area ventilation system are non-safety related ventilation systems and are not credited for any design basis event. The applicant further stated that the control rod drive ventilation system and the incore instrumentation area ventilation system are listed in

Table 8-1 of McGuire UFSAR as loads on the emergency diesel generators (EDGs) and that these systems, when powered by the EDGs, provide additional containment cooling and are not required to mitigate the consequences of design basis events. The staff finds the applicant's response acceptable because the control rod drive ventilation system and the incore instrumentation area ventilation system are not safety-related or credited for any design basis event and are not, therefore, within the scope of license renewal as defined in 10 CFR 54.4.

By letter dated January 23, 2002, the staff requested, in RAI 2.2.1-2, that the applicant provide the basis for listing the diesel building in LRA Table 2.2-3 as not being within the scope of license renewal, and for listing the Unit 1 and 2 diesel generator buildings in LRA Table 2.2-1 as within the scope of license renewal. In its response dated March 1, 2002, the applicant stated that the diesel building (#7434) is outside the protected area, houses power for the non-vital telecommunications building, and, as such, is not within the scope of license renewal. The applicant further explained that the Unit 1 and 2 diesel generator buildings house the emergency diesel generators and are within the scope of license renewal. Since the applicant explained that the diesel building listed in Table 2.2-3 does not meet any of the scoping criteria for license renewal, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.2.1-3, that the applicant provide the basis for listing the radwaste facility and the retired steam generator (SG) storage facility on Table 2.2-3 of the LRA as not being within the scope of license renewal. These structures contain significant levels of radioactivity and, as documented in Section 12.1.2.1 of the McGuire UFSAR, are shielded by thick concrete walls. In its RAI, the staff asked if an intended function of these walls is to mitigate the consequences of accidents that could result in potential offsite exposure. In its response dated March 1, 2002, the applicant stated that the walls of the radwaste facility and of the retired SG storage facility are designed for shielding and are not designed to mitigate the consequences of accidents that could result in potential offsite exposure comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11. Since the applicant demonstrated that the walls of the radwaste facility and of the retired SG storage facility do not meet the scoping criteria for license renewal as defined in 10 CFR 54.4, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.2.1-4, that the applicant provide the basis for listing the condensate system and the condensate storage system on LRA Table 2.2-3, as not being within the scope of license renewal. In its RAI, the staff referred to its February 19, 1992, safety evaluation for SBO for McGuire. In that safety evaluation, the staff stated that there was sufficient water to cope with decay heat removal during a 4-hour SBO event at McGuire, based on the ability to align the turbine-driven AFW pump to the AFW storage tank, the upper surge tank, and the condenser hotwell, as well as the ability to align the AFW to the condenser circulating water (CCW) system. In its response dated March 1, 2002, the applicant quoted another section of the February 19, 1992, safety evaluation—

> There are, however, no technical specifications limits on the levels of these water sources, and therefore, there are no guarantees that these sources of condensate will be available during an SBO event. If, for any reason, sufficient sources of condensate-grade water are unavailable, the licensee can align the turbine-driven AFW pumps to take suction from the CCW system, which can provide non-condensate-grade water for 72 hours. Therefore, McGuire has sufficient sources of water to cope with a four-hour SBO.

The staff finds the applicant's response acceptable because, as stated in the February 19, 1992, safety evaluation, there are no technical specifications limits on the condensate system and the condensate storage system water level, the systems are not relied upon in the plant evaluation to perform a function that demonstrates compliance with the SBO regulations, and, therefore, these systems are not within the scope of license renewal as defined in 10 CFR 54.4(a)(3).

By letter dated January 23, 2002, the staff requested, in RAI 2.2.1-5, that the applicant provide the basis for listing the retired SG facility on Table 2.2-4 of the LRA as not being within the scope of license renewal. This structure contains significant levels of radioactivity and, as documented in Section 12.1.2.1 of the Catawba UFSAR, is shielded by thick concrete walls. In its RAI, the staff questioned the intended function of these walls to mitigate the consequences of accidents that could result in potential offsite exposure. In its response dated March 1, 2002, the applicant stated that the walls of the retired SG facility are designed for shielding and are not designed to mitigate the consequences of accidents that could result in potential offsite exposure comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11. Because the applicant explained that these structures did not meet the scoping criteria for license renewal as defined in 10 CFR 54.4, the staff finds the applicant's response acceptable.

### 2.2.4 Conclusion

On the basis of its review of the information presented in Sections 2.2-1 and 2.2-2 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the information provided in response to RAIs, the staff concludes that there is reasonable assurance that the applicant has identified all SSCs whose intended functions meet the scoping requirements of 10 CFR 54.4.

## <u>2.3 System Scoping and Screening Results: Mechanical</u>

2.3.1 System Scoping and Screening Results: Reactor Coolant System

In Section 2.3.1, "Reactor Coolant System," of the LRA, the applicant described the SSCs of the reactor coolant system (RCS) that are subject to AMR for license renewal. The following RCS Class 1 components were described in Section 2.3.1 of the LRA—

- Class 1 piping, valves, and pumps
- pressurizer
- reactor vessel (RV) and control rod drive mechanism (CRDM) pressure boundary
- reactor vessel internals
- steam generator

*2.3.1.1 Reactor Coolant System*

In the McGuire and Catawba LRA, Section 2.3.1.1, "Reactor Coolant System Description," the applicant describes the RCS and RCS components that are within the scope of license renewal and subject to an AMR for McGuire and Catawba. The RCSs are similar for both facilities, and unless otherwise specified, the information provided below is applicable to the McGuire and Catawba RCSs. The McGuire UFSAR Chapter 5, "Reactor Coolant System," and the Catawba

UFSAR Chapter 5, “Reactor Coolant System,” provide additional information concerning the McGuire and Catawba RCSs, respectively.

### 2.3.1.1.1 Technical Information in the Application

As described in the LRA, the RCS consists of four similar heat transfer (HT) loops connected in parallel to the reactor pressure vessel. Each loop contains a reactor coolant pump (RCP), steam generator, and associated piping and valves. In addition, the system includes a pressurizer, a pressurizer relief tank (Class F), interconnecting piping, and instrumentation necessary for operational control. All major components are located in the reactor building.

During operation, the RCS transfers the heat generated in the core to the SGs, where steam is produced to drive the turbine generator. Borated demineralized water is circulated in the RCS at a flow rate and temperature consistent with achieving the reactor core thermal-hydraulic performance. The water also acts as a neutron moderator and reflector and as a solvent for the neutron absorber used in chemical shim control.

The RCS pressure boundary provides a barrier against the release of radioactivity generated within the reactor, and is designed to ensure a high degree of integrity throughout the life of the unit. RCS pressure is controlled by the use of the pressurizer, where water and steam are maintained in equilibrium by electrical heaters or water sprays. Steam can be formed (by the heaters) or condensed (by the pressurizer spray) to minimize pressure variations due to contraction and expansion of the reactor coolant. Spring-loaded safety valves and power-operated relief valves (PORVs) are mounted on the pressurizer and discharged to the pressurizer relief tank, where the steam is condensed and cooled by mixing with water.

Chapter 5, “Reactor Coolant System,” of both McGuire and Catawba UFSARs, provides additional information concerning the McGuire and Catawba reactor coolant systems. The component types, component functions, materials of construction, environments, aging effects, and aging management programs (AMPs)/activities for the McGuire and Catawba RCS are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include exterior surfaces of pressure boundary components, valve bolting material, reactor coolant pump main flange bolts, pressurizer manway cover bolts/studs, reactor vessel closure studs, nuts and washers, SG bolting, reactor vessel, and pressurizer integral attachments.

### 2.3.1.1.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the RCS components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba pertaining to the RCS and associated pressure boundary components, and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function or functions, the staff sought to verify that they either perform the function or functions with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation. The staff did not identify any omissions.

2.3.1.1.3 Conclusions

On the basis of its review of the information presented in Section 2.3.1.1 of the LRA and the supporting information in the McGuire and Catawba UFSARs, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the RCS and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

*2.3.1.2 Class 1 Piping, Valves and Pumps*

In the McGuire and Catawba LRA, Section 2.3.1.2, “Class 1 Piping, Valves and Pumps,” the applicant describes the RCS Class 1 piping and associated components that are within the scope of license renewal and subject to an AMR for McGuire and Catawba. The Class 1 piping and associated components are similar for both facilities, and unless otherwise specified, the information provided below is applicable to McGuire and Catawba. The McGuire UFSAR Section 5.5, “Component and Subsystem Design,” and the Catawba UFSAR Section 5.4, “Component and Subsystem Design,” provide additional information concerning the McGuire and Catawba RCS Class 1 piping and associated components, respectively.

2.3.1.2.1 Technical Information in the Application

The RCS Class 1 piping and associated pressure boundary components consist of the following items—

- Westinghouse-supplied primary loop piping which interconnects the reactor vessel, SGs, and reactor coolant pumps
- Duke-designed Class 1 piping
- pressure boundary portion of Class 1 valves (bodies and bonnets, bolting)
- pressure boundary portion of the reactor coolant pump (casing, main closure flange thermal barrier heat exchanger and bolting)

The Westinghouse-supplied primary loop piping consists of four loops of piping interconnecting the reactor vessel, SG, and reactor coolant pump in each loop. This piping includes branch connection nozzles and special items such as the RTD scoop elements, pressurizer spray scoop, sample connection scoop, reactor coolant temperature element installation boss, and the temperature element well.

Class 1 branch piping consists of piping connected at the Westinghouse-supplied primary loop piping out to and including (1) the outermost containment isolation valve (CIV) 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 Class 1 branch lines and instrument connections in the RCS are equipped with ⅜-inch inner diameter (ID) flow restricting orifices that limit the maximum flow from a break downstream of the flow restriction to below the makeup capability of the RCS. This orifice is used instead of double isolation valves to make the break from Class 1 to Class 2.

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 of the component includes the pump casing, the main closure flange, the thermal barrier heat exchanger within the reactor coolant pump, the reactor coolant pump seals, and the pressure retaining bolting. The reactor coolant pump seals are excluded from AMR because they are periodically replaced. Preventive maintenance is currently scheduled every three cycles for the reactor coolant pump seals unless data indicates that the inspection must be done more frequently.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba reactor coolant system Class 1 piping and associated pressure boundary components are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include hot and cold leg pipes, elbows, pipe fittings, branch connections, orifices, valve bodies and/or bonnets, reactor coolant pump casings, main pump closure flange, and thermal barrier heat exchanger piping (tubing) and flanges.

2.3.1.2.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the Class 1 piping and associated pressure boundary components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the Class 1 piping and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under

10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts, or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4 (a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation. The staff did not identify any omissions.

2.3.1.2.3 Conclusions

On the basis of its review of the information presented in Section 2.3.1.2 of the LRA, and the supporting information in the McGuire and Catawba UFSARs, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the Class 1 piping and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

*2.3.1.3 Pressurizer*

In the McGuire and Catawba LRA, Section 2.3.1.3, “Pressurizer,” the applicant describes the pressurizer and associated components that are within the scope of license renewal and subject to an AMR for McGuire and Catawba. The pressurizer and associated components are similar for both facilities, and unless otherwise specified, the information provided below is applicable to McGuire and Catawba. The McGuire UFSAR Section 5.5.10, “Pressurizer,” and the Catawba UFSAR Section 5.4.10, “Pressurizer,” provide additional information concerning the McGuire and Catawba pressurizers and associated components, respectively.

2.3.1.3.1 Technical Information in the Application

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads that is connected to the RCS on one of the hot legs of a coolant loop. Electrical heaters are installed through the bottom head of the pressurizer while the spray nozzle, relief, and safety valve connections are located in the top head of the pressurizer. The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for all four of the McGuire and Catawba pressurizers are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include lower head shell, upper head manway, surge nozzle, spray nozzle, relief nozzle, safety nozzle, immersion heaters sheath, surge and spray nozzle thermal sleeves, support skirt and flange, manway insert, heater well nozzle, instrument nozzles, surge nozzle safe end, spray nozzle safe end, relief nozzle safe end, and safety nozzle safe end.

2.3.1.3.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the pressurizer components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the pressurizer and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

During its review, the staff noted that some Westinghouse pressurizers are designed with seismic lugs and valve support bracket lugs. By letter dated January 28, 2002, the staff requested, in RAI 2.3.1-2, the applicant to verify whether such components exist in McGuire and Catawba plants; and if they do, then the applicant should explain why the subject components do not require an AMR. Based on past license renewal reviews, the staff believes that the subject components should be within scope requiring aging management, provided the pressurizers are designed with such components. In its response dated April 15, 2002, the applicant stated that the pressurizer seismic lugs are integral attachments to the pressurizer and are included in LRA Table 3.1-1 as “Reactor Vessel and Pressurizer Integral Attachments” (page 3.1-6, row 2). The valve support brackets are not used at McGuire and Catawba to provide support for safety and relief valves. The safety and relief valves are supported by pipe supports that attach to the pressurizer cavity wall. The staff agrees that the valve support brackets are outside the scope of license renewal, because they do not perform an intended function under 10 CFR 54.4(a)(1) and are not necessary to demonstrate compliance with any requirements referenced in 10 CFR 54.4(a)(3). The staff did not identify any omissions.

#### 2.3.1.3.3 Conclusions

On the basis of its review of the information presented in Section 2.3.1.3 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant’s response to the requests for additional information, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the pressurizer system and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

### *2.3.1.4 Reactor Vessel and Control Rod Drive Mechanism (CRDM) Pressure Boundary*

In the McGuire and Catawba LRA, Section 2.3.1.4, "Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary," the applicant describes the reactor vessel and CRDM and associated components that are within the scope of license renewal and subject to an AMR for both McGuire and Catawba. The reactor vessel and CRDM and associated components are similar for both facilities, and unless otherwise specified, the information provided below is applicable to the McGuire and Catawba. The McGuire UFSAR Section 5.4, "Reactor Vessel," and the Catawba UFSAR Section 5.3, "Reactor Vessel," provide additional information concerning the McGuire and Catawba reactor vessel and associated components, respectively.

#### 2.3.1.4.1 Technical Information in the Application

The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the core, core supporting structures, control rods and other parts directly associated with the core. The upper (closure) head contains 82 penetrations (78 for CRDM and 4 auxiliary head adapters). The vessel has inlet and outlet nozzles located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the annulus between the core barrel and the vessel wall, turns at the bottom, and flows up through the core to the outlet nozzles.

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

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for all four of the McGuire and Catawba reactor vessels are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include closure head dome, flange, ring and vessel flange, upper (nozzle) shell, primary inlet and outlet nozzles, inlet and outlet nozzle safe ends, intermediate shell, lower shell, bottom head spherical ring, dome, CRDM housings, upper head injection (UHI) auxiliary head adapter flange, head vent penetration, thimble assembly, bottom-mounted instrumentation (BMI) tubes (penetrations), thimble guide tubes, thimble seal table, and core support pads.

#### 2.3.1.4.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the reactor vessel and CRDM components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an

AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the reactor vessel, CRDM, and associated pressure boundary components, and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4 (a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

Wastage of carbon steel induced by borated water leakage through the pressure boundary in PWRs is a potential aging degradation for the components. Reactor vessel head lifting lugs are considered to be such components requiring aging management. However, if the components are currently covered under the Fluid Leak Management Program, then they may not require additional aging management. It appears that the subject components were not discussed in the LRA. By letter dated January 28, 2002, the staff requested, in RAI 2.3.1-1, the applicant to verify whether the components are within the surveillance program; and if not, to provide an explanation.

In its response dated April 15, 2002, the applicant stated that the reactor vessel head lifting lugs are considered to be a part of the exterior surfaces of RCS pressure boundary components that are listed in Table 3.1-1 (page 3.1-5, row 1) of the LRA. The aging effect of the reactor vessel head lifting lugs is managed by the Fluid Leak Management Program, which is described in Appendix B, Section B.3.15 of the LRA. The Fluid Leak Management Program is credited for managing loss of material due to boric acid wastage for alloy steel components such as the reactor vessel head lifting lugs. The staff agrees that the lifting lugs are within the scope of license renewal and are subject to the Fluid Leak Management Program, since the lugs are considered to be piece parts of the RCS pressure boundary. The staff did not identify any omissions.

2.3.1.4.3 Conclusions

On the basis of its review of the information presented in Section 2.3.1.4 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant's response to staff's RAI, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the reactor vessel and CRDM system and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

*2.3.1.5 Reactor Vessel Internals (RVI)*

In the McGuire and Catawba LRA, Section 2.3.1.5, "Reactor Vessel Internals," the applicant describes the RVI and associated components that are within the scope of license renewal and subject to an AMR for McGuire and Catawba. The RVI and associated components are similar for both facilities, and unless otherwise specified, the information provided below is applicable to the McGuire and Catawba. The McGuire UFSAR Section 4.2.2, "Reactor Vessel Internals," and the Catawba UFSAR Section 3.9.5, "Reactor Vessel Internals," provide additional information concerning the McGuire and Catawba reactor vessel internals and associated components, respectively.

2.3.1.5.1 Technical Information in the Application

The components of the reactor internals are divided into three parts consisting of the lower core support structure (including the entire core barrel and neutron shield pad assembly), the upper core support structure, and the in-core instrumentation support structure. The RVI support the core, maintain fuel alignment, limit fuel assembly movement, maintain alignment between fuel assemblies and CRDMs, direct coolant flow past the fuel elements and to the pressure vessel head, provide gamma and neutron shielding, and provide guides for the in-core instrumentation. The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for all four of the McGuire and Catawba RVI are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include upper support assembly, upper support column, upper support column bolts, upper core plate, upper core plate alignment pins, fuel alignment pins, hold-down spring, thermocouple column and crossrun assemblies, 17x17 and 15x15 guide tube assembly, UHI flow columns, core barrel flange, core barrel outlet nozzles, neutron panels, irradiation specimen holder, fasteners, baffle and former plates, baffle bolts, lower core plate, lower support column bolts, lower support plate, lower core support columns, radial keys and fasteners, clevis inserts and fasteners, and bottom-mounted instrumentation.

2.3.1.5.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the RVI components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the RVI and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

Section 3.9.1.3, page 3.9-4 of McGuire UFSAR states that the diffuser plate was relied upon when performing the dynamic system load analyses for reactor internals at McGuire to determine the behavior of lower structures when subjected to loads. Furthermore, based on past license renewal reviews of Westinghouse plants, the staff believes that the diffuser plate (provided there is one) should be within the scope requiring aging management because the component provides the safety function of structural and/or functional support for in-scope equipment, and/or provides flow distribution. By letter dated January 28, 2002, the staff requested, in RAI 2.3.1-3, the applicant to confirm whether the subject component was identified to be within scope requiring aging management for McGuire; and if not, to explain why. The staff further requested that the applicant update the UFSAR to correct the information. In its response dated April 15, 2002, the applicant stated that Duke’s investigation in preparing the response to RAI 2.3.1-3 had revealed that the summary analysis provided in UFSAR Section 3.9.1.3 of the McGuire UFSAR is a generic analysis that was provided by Westinghouse, the McGuire nuclear steam supply system vendor. The analysis described in the UFSAR reflects an earlier Westinghouse plant design that bounds the McGuire design. A review of plant drawings and communications between the applicant and Westinghouse confirmed that the McGuire RVI do not have a diffuser plate. The applicant stated that a Problem Investigation Process (PIP) report was initiated to clarify McGuire UFSAR Section 3.9.1.3. The applicant's assessment is acceptable, and the staff did not identify any omissions.

2.3.1.5.3 Conclusions

On the basis of its review of the information presented in Section 2.3.1.5 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant’s response to the requests for additional information, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the RVI and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

*2.3.1.6 Steam Generator*

In the McGuire and Catawba LRA, Section 2.3.1.6, “Steam Generator,” the applicant describes the SG and associated components that are within the scope of license renewal and subject to an AMR for McGuire and Catawba. The SGs and associated components are similar for both facilities, and unless otherwise specified, the information provided below is applicable to the McGuire and Catawba. The McGuire UFSAR Section 5.5.2, “Steam Generator,” and the Catawba UFSAR Section 5.4.2, “Steam Generator,” provide additional information concerning the McGuire and Catawba SGs and associated components, respectively.

2.3.1.6.1 Technical Information in the Application

The replacement steam generators (RSGs) at McGuire 1 and 2 and Catawba 1 were manufactured by Babcock & Wilcox International in Cambridge, Ontario, Canada. The McGuire 1 SGs were replaced in May 1997, and the McGuire 2 SGs were replaced in December 1998. The Catawba 1 SGs were replaced in October 1996. For Catawba 2, the SGs that were installed during original construction have not been replaced.

All SGs at both stations are vertical shell and U-tube evaporators with integral moisture separating equipment. Reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles equipped with stainless steel safe ends located in the hemispherical bottom head of the SG. Steam is generated on the shell side of the tubes and flows upward through the moisture separators to the outlet nozzle at the top of the SG. Feedwater flows directly into a downcomer section and is mixed with saturated recirculation flow before entering the tube bundle for the replacement SGs. The Catawba 2 SGs are equipped with a preheater and feedwater flow restriction, with main feedwater delivered just above the tube sheet. Subsequently, the water-steam mixture flows upward through the tube bundle and into the steam drum section. Centrifugal moisture separators, located above the tube bundle, remove most of the entrained water from the steam.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for all 16 of the McGuire and Catawba SGs are listed in Table 3.1-1 of the LRA. The component types that were identified in the table include primary head/cladding, primary nozzle closure rings, secondary manway, secondary manway covers, handhole covers, handhole pad, tubesheet/primary and secondary cladding, tubes/plugs, primary nozzles, primary nozzle safe ends, primary manway cover, plate/diaphragm, primary divider plate, steam drum boiler shells, steam dome conical shells, handhole, handhole diaphragm, small nozzles, primary manway and manway insert, primary chamber drain and coupling, feedwater thermal sleeve, feedwater limiter, steam outlet nozzle, flow restriction, steam outlet nozzle safe end, auxiliary feedwater nozzle, main feedwater nozzle, steam outlet nozzle, auxiliary feedwater nozzle safe end, and auxiliary feedwater distribution system.

2.3.1.6.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the SG components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the SG and associated pressure boundary components, and compared the information in the UFSAR with the information in the LRA, to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

Table 3.1-1 of the LRA identifies components for the SGs that require AMR. The following components were not listed in the table-anti-vibration bars, stay rod, tube bundle wrapper, and tube support plates. Based on past LRA reviews for the Westinghouse plants, and on the information provided in McGuire and Catawba UFSARs, the staff believes that these components perform the intended function of providing structural and/or functional support for in-scope equipment, namely the SG tubes, and, therefore, should be within the scope of license renewal and subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.1-4, the applicant to determine if the intended function of the above components to provide structural and/or functional support for the SG tubes is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) by confirming that none of the above-mentioned components in McGuire and Catawba units are credited for preventing tube failure during seismic events or during a main steam-line break accident. In its response dated April 15, 2002, the applicant stated that upon further review, Duke concluded that tube support structures on the secondary side of the SGs are within scope and subject to AMR. The tube support structures include items such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring, and U-bend arch bars for the replacement SGs at McGuire 1 and 2 and Catawba 1. For Catawba 2 SGs, items such as anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates are included. The applicant further stated that the items for all four units are included as “tube supports.” The AMR results for the tube supports, as proposed in the RAI response, are provided below and used to supplement Table 3.1.1 of the LRA—

- component type-SG tube supports
- component function-support
- material-alloy steel, stainless steel, carbon steel
- environment-treated water
- aging effect-cracking, loss of material
- aging management programs and activities-Chemistry Control Program, SG Surveillance Program

Because the applicant agreed that the SG subcomponents described in RAI 2.3.1-4 are within the scope of license renewal, the applicant's assessment of scoping and screening of SG sub-components is acceptable. The staff did not identify any additional omissions. The adequacy of the proposed aging management programs and activities for the tube supports is discussed in Section 3.1.5.2 of this SER.

2.3.1.6.3 Conclusions

The staff identified that the applicant did not include the tube supports of the SGs as within the scope of license renewal and subject to an AMR for McGuire and Catawba. However, the applicant subsequently added the SG tube supports to the scope of components subject to an AMR and provided the AMR results to the staff for review. The staff's evaluation of the AMR results for the SG support components is provided in Section 3.1.5.2 of this SER. Since no additional omissions were identified, the staff concludes that, on the basis of its review of the information presented in Section 2.3.1.6 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant's response to RAIs, there is reasonable assurance that the applicant adequately identified those portions of the SG and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

### 2.3.2 System Scoping and Screening Results: Engineered Safety Features

In Section 2.3.2, "Engineered Safety Features," of the McGuire and Catawba LRA, the applicant described the SSCs of the engineered safety features (ESFs) that are subject to an AMR for license renewal.

#### *2.3.2.1 Annulus Ventilation System*

In Section 2.3.2.1 of the LRA titled, "Annulus Ventilation System," the applicant identified portions of the annulus ventilation (VE) system and its components that are within the scope of license renewal and subject to AMR. The applicant noted in Section 2.3.2.1 of the LRA that the VE system is further described in Section 6.2 of both the McGuire and Catawba UFSARs.

The applicant evaluated component supports for heating, ventilation, and air-conditioning ductwork listed in Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the VE system in Section 2.1.2 of the LRA. The staff's scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff's evaluation of electrical components and instrumentation and controls in the VE system is documented in Section 2.5 of this SER.

##### 2.3.2.1.1 Technical Information in the Application

The independent VE system for all four units is considered an engineered safety feature (ESF). Each VE system has redundant trains consisting of a makeup air supply fan, a moisture eliminator, a filter train and associate piping, valves, and controls as necessary to accomplish the design bases. All major annulus ventilation components are located in the auxiliary building.

Two 100 percent capacity VE system exhaust fans and corresponding filtration (FI) trains are provided for each unit. The fans and filtration trains are supplied with both normal and class 1E emergency power. The moisture eliminator consists of a mechanical demister and a heater, which are designed to limit the relative humidity entering the filter train to below 70 percent, assuming intake air at 100 percent relative humidity. Each carbon filter is sized to accommodate the fission products released into the annulus following any of the postulated accidents. If one ventilation subsystem fails, the transfer of function to the other ventilation subsystem is performed manually from the control room by the operator.

The VE system functions to discharge sufficient air from the annulus to achieve and maintain a negative pressure with respect to the containment and the outside atmosphere following a loss-of-coolant accident (LOCA). In order to mix the inleakage in as large a volume as possible, a large flow of air is displaced from the upper level of the annulus, passed through the filter, and returned to the annulus at a low level. The applicant stated in the LRA that the VE system is further described in Section 6.2 of the McGuire and Catawba UFSARs. In Section 2.3.2.1 of the LRA, and Sections 6.1.8 and 9.4.9.1 of the McGuire and Catawba UFSARs, respectively, the applicant identified the following intended functions of the McGuire and Catawba VE system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

McGuire

Section 2.3.2.1 of the LRA—

- to create and maintain a negative pressure zone in the annular space between the steel primary containment and reactor building (secondary containment)
- to prevent the leakage of radioisotopes through the reactor building and into the environment, following a LOCA
- to maintain containment isolation integrity

Section 6.1.8 of the UFSAR—

- to maintain a post-accident negative pressure in the annulus between the containment and the reactor building, and collect and filter gaseous leakage from the containment during accident conditions
- to produce a slight negative pressure within the annulus, thus preventing outleakage and relieving the post-accident thermal expansion of air in the annulus
- to keep outleakage minimal (the reactor building also serves as a protective structure)
- to collect, delay, and filter gases leaking from the containment vessel

Catawba

Section 2.3.2.1 of the LRA—

- to limit operator and site boundary dose, following a design basis accident, to within the guidelines specified in 10 CFR Part 100
- to provide long-term fission product removal capability within the annulus through holdup and filtration

Section 9.4.9.1 of the UFSAR—

- to limit operator and site boundary doses following a design basis accident (DBA) to within 10 CFR 100 guidelines
- to produce and maintain a negative pressure of 0.25 inches water gauge throughout the annulus
- to reduce the concentration of radioactivity (specifically radioiodines) in the air within, and discharged from, the annulus through filtration and recirculation of annulus air
- to provide long-term fission product removal capacity within the annulus through holdup, decay, and filtration
- to minimize the release of radioactivity (specifically radioiodines) from the containment to the environment following a design basis LOCA

On the basis of the intended functions identified above for the McGuire and Catawba VE systems, the portions of these systems that were identified by the applicant as within the scope of the LRA include all VE system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1.2 of the LRA. On the basis of this methodology, the applicant identified the portions of the VE system that are within scope on the flow diagrams listed in Section 2.3.2.1 of the LRA. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams, and identified their intended functions. The applicant provided this list in Table 3.2-1 of the LRA.

The following component types are identified in Table 3.2-1 of the LRA as within the scope of license renewal and subject to an AMR-air flow monitors, ductwork, filters, pipe (McGuire only), valve bodies, and tubing. The applicant further noted in Table 3.2-1 of the LRA that the VE system pressure boundary function is the only applicable intended function of annulus mixing components that are subject to an AMR.

2.3.2.1.2 Staff Evaluation

To verify that the applicant identified the components of the VE system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagrams listed in Section 2.3.2.1 of the LRA that show the evaluation boundaries for the highlighted portion of the VE system that are within scope, and Table 3.2-1 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed UFSAR Sections 6.1.8 and 9.4.9 to determine if there were any portions of the VE system that met the scoping criteria in 10 CFR 54.4(a), but were not identified as within the scope. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA, and to determine if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VE system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.2-1 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled components from Table 3.2-1 of the LRA to verify that the applicant did identify the components subject to an AMR. The staff also sampled the structures and components that were within the scope of the LRA but not subject to an AMR. Based on this sample, the staff verified that these structures and components perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VE system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and LRA descriptions. The staff noted that Section 2.3.2.1 of the LRA provides a summary description of the system functions and a listing of flow diagrams. The flow diagrams highlight the evaluation boundaries, and Table 3.2-1 of the LRA tabulates the components within the scope and subject to an AMR for the VE system.  The corresponding drawings and UFSARs, however, show additional components that were not listed in Table 3.2-1 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR.  The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function, and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of fan housings from the scope of license renewal and/or an AMR.  In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA.  The applicant added that cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21.  The staff reviewed this response and determined that the applicant's basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are, therefore, within the scope of license renewal.  Furthermore, because the fan housings are passive long-lived components, they are subject to an AMR.  The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-2, specific information concerning the exclusion of damper housings from the scope of license renewal and/or an AMR.  In its response dated April 15, 2002, the applicant stated that dampers are not included in the AMR results tables in the LRA.  The applicant added that ventilation dampers, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21.  The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain the pressure boundary integrity (as are valve bodies and pump casings) and are, therefore, within the scope of license renewal.  Furthermore, because the damper housings are passive long-lived components, they are subject to an AMR.  The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the annulus ventilation system fan and damper housings that are in scope at McGuire and Catawba.  On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2.  The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation.  The staff's evaluation of the AMR results is documented in Section 3.2.1.2 of this SER.  Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-4, specific information concerning the exclusion of building sealants from the scope of license renewal and/or an AMR.  In its response dated April 15, 2002, the applicant stated that it does not define materials such as sealants to be structures or components.  The applicant stated the pressure boundary function is addressed by technical specification surveillance testing.  However, the applicant did not indicate that any of the technical specificaiton surveillance requirements (TSSRs) listed in its response were credited for aging management (and identified as AMPs).  Nor did the applicant furnish a description of or information pertaining to a TS surveillance AMP (including discussion of the 10 elements of the AMP) for the staff's review.

On page 2.1-24 of the LRA, the applicant stated that "seals associated with maintaining pressure boundary are limited to the divider barrier seals in the reactor building." Since the applicant does not discuss the treatment of structural sealants other than the divider barrier seal, it is not clear to the staff that building (structural) sealants were considered during an AMR of the structure (building) for which they are a subcomponent. Furthermore, according to page 3.5-10 of the LRA, the Inspection Program for Civil Engineering Structures and Components is credited by the applicant to monitor the aging of building concrete structural components (reinforced concrete beams, columns, floor slabs, and walls). According to Section B.3.21, of Appendix B of the LRA, the scope of the Inspection Program for Civil Engineering Structures and Components does not include structural sealants. Table 2.1-3, on page 2.1-15 of the SRP-LR, states that an applicant's structural AMP is expected to address structural sealants "with respect to an AMR program." The intent of this statement is that an applicant's structural AMP is expected to manage or monitor the aging effects of the structure and associated sub-components that are identified during the AMR. The basis for this SRP guidance is documented in the summary (issued January 21, 2000) of a December 8, 1999, meeting to discuss the staff's position on the treatment of consumables. This summary clearly states, on page 3, that structural sealants would be implicitly included at the component level and considered during the AMR. Since the structural AMP identified for the concrete structural components does not address structural sealants, and since that applicant did not identify the TS surveillances listed in its response as AMPs, or provide appropriate information to support the staff's review of these surveillances as AMPs, the staff characterized this issue as SER open item 2.3-3.

In its response to this open item, dated October 28, 2002, the applicant credited a visual inspection of the structural sealant used to maintain ventilation pressure boundary integrity of the control room area, emergency core cooling pump rooms, annulus, and fuel handling building. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open item 2.3-3. The staff's evaluation of the Ventilation Area Pressure Boundary Sealants Inspection Program is provided in Section 3.0.3.19 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-5, specific information concerning the exclusion of passive components associated with ductwork from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified these passive components as subcomponents of ductwork. The applicant also stated that ventilation grilles were installed only for aesthetic purposes and perform no intended license renewal function. Because passive components associated with ventilation ductwork referenced in RAI 2.3-5 perform no intended function, the staff agrees that they are not within the scope of license renewal.

Some components that are common to many systems, including the VE system, have been evaluated separately by the applicant in LRA Section 2.1.2.1.2 as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this report, the staff evaluated component supports for piping, cables, and equipment, which are discussed in LRA Section 2.4, "Scoping and Screening Results: Structures." In Section 2.5 of this report, the staff evaluated electrical components that support the operation of the VE system, which are discussed in LRA Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls.” The VE system instrumentation lines are evaluated with the VE system and are listed in Table 3.2-1 of the LRA as tubing.

The staff reviewed the LRA, supporting information in the UFSAR, and the applicant’s responses to RAIs. In addition, the staff sampled several components from the VE system flow diagram, as identified in LRA Section, to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

#### 2.3.2.1.3 Conclusions

On the basis of its review, and with the resolution of open items identified in this SER section, the staff has reasonable assurance that the applicant has adequately identified the VE system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

### *2.3.2.2 Containment Isolation System*

In Section 2.3.2.2 of the LRA, the applicant described the systems isolated by the containment isolation system and the components therein which are within the scope of license renewal and subject to an AMR. The containment isolation system is further described in Section 6.2.4 of the McGuire and Catawba UFSARs.

#### 2.3.2.2.1 Technical Information in the Application

The containment isolation system is an ESF with the intended function of isolating all nonessential fluid-bearing lines penetrating the containment in order to prevent the uncontrolled or unmonitored release of radioactivity to the environment. The applicant identified the following 12 systems as being isolated by the containment isolation system—

- breathing air system
- containment air release and addition system
- containment hydrogen sample and purge system (Catawba only)
- containment purge ventilation system
- containment ventilation cooling water system (McGuire only)
- conventional chemical addition system (McGuire only)
- equipment decontamination system
- ice condenser refrigeration system
- makeup demineralized water system
- station air system
- steam generator blowdown recycle system
- steam generator wet lay-up recirculation system

Based on the intended function of the containment isolation system identified above, the applicant identified the following five component types in this system as within the scope of license renewal and subject to an AMR-valve bodies, piping, tubing, orifices, and annubars.

The applicant further identified the intended functions of these component types to be maintaining the integrity of the containment isolation system pressure boundary.

### 2.3.2.2.2 Staff Evaluation

The staff reviewed Section 2.3.2.2 of the LRA, and the associated piping and instrumentation diagrams (P&IDs) to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment isolation system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff then reviewed the AMR results provided in Table 3.2-2 of the LRA to determine whether the applicant appropriately identified the components belonging to the containment isolation system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). In order to perform a conservative review, the staff focused on those components of the containment isolation system that were not identified as meeting the above requirements. The staff also reviewed Section 6.2.4 of the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted from Section 2.3.2.2 of the applicant's LRA.

As discussed below, the applicant considered within the scope of license renewal only the components of the containment isolation system which function as a pressure boundary to support containment isolation. The staff finds this approach to be acceptable because the 12 systems included in the containment isolation system are nonessential except for their containment isolation function. In its initial review, however, the staff identified seven instances on five containment isolation system piping and instrumentation diagrams where piping and valve bodies that appeared to serve as a pressure boundary for the containment isolation intended function had not been highlighted as within the scope of license renewal. As detailed in a telecommunication summary dated November 14, 2001, the applicant confirmed that these seven license renewal scoping boundaries had been incorrectly highlighted on the diagrams, and that the piping and valve bodies inadvertently omitted were actually considered to be within the scope of license renewal and subject to an AMR. In the same telecommunication summary, the staff also questioned whether the Catawba containment hydrogen sample and purge system was used to provide post-accident containment hydrogen concentration samples on which the manual operation of the containment hydrogen recombiners would be based. The applicant indicated that the containment hydrogen sample and purge system was not credited for this function, and that the safety-related hydrogen analyzers (which the applicant classified as part of the miscellaneous instrumentation system, reviewed in Section 2.3.2.9 of this SER) are credited with providing an indication of post-accident hydrogen concentration. The staff finds the applicant's responses satisfactory because they (1) support the conclusion that all components required for the containment isolation intended function are considered within the scope of license renewal, (2) support the conclusion that the twelve non-essential systems isolated by the containment isolation system do not have intended functions other than containment isolation, and (3) are consistent with the general information and descriptions concerning the containment isolation system provided in the LRA.

### 2.3.2.2.3 Conclusions

The staff concludes that, for both McGuire and Catawba, there is reasonable assurance that the applicant has appropriately identified the components of the containment isolation system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

*2.3.2.3 Containment Air Return Exchange and Hydrogen Skimmer System*

In Section 2.3.2.3 of the LRA, the applicant described the containment air return exchange and hydrogen skimmer system and the components therein which are within the scope of license renewal and subject to an AMR. This system is further described in Section 6.2 of the McGuire and Catawba UFSARs.

2.3.2.3.1 Technical Information in the Application

The containment air return exchange and hydrogen skimmer system is an ESF with the following three intended functions (1) maintaining containment pressure less than its design value during a postulated high-energy line break (HELB) by recirculating air from the upper containment to the lower containment, (2) ensuring the hydrogen concentration remains less than the flammability limit following a postulated loss-of-coolant accident by preventing hydrogen pocketing in dead-ended compartments within containment, and (3) maintaining containment isolation capability for the system piping penetrating containment. The containment air return portion of this system employs two redundant air return fans, dampers, and ductwork (Catawba only) to recirculate air from upper containment to lower containment in response to a postulated high-energy line break. The hydrogen skimmer portion of this system employs two redundant hydrogen skimmer fans, piping, dampers (McGuire only), and expansion joints (Catawba only) to skim hydrogen from compartments in which hydrogen may accumulate following a postulated loss-of-coolant accident. The pressure boundary of the hydrogen skimmer portion of this system consists of piping, rather than ductwork, to prevent rupture and consequent ice condenser bypass leakage following a postulated accident.

Based on the three intended functions of the containment air return exchange and hydrogen skimmer system identified above, the applicant identified the following five component types of this system as within the scope of license renewal and subject to an AMR-piping, tubing, valve bodies, ductwork (Catawba only), and expansion joints (Catawba only). The applicant further identified the intended functions of these component types to be maintaining the integrity of the containment air return exchange and hydrogen skimmer system pressure boundary.

2.3.2.3.2 Staff Evaluation

The staff reviewed Section 2.3.2.3 of the LRA, and the associated piping and instrumentation diagrams, to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment air return exchange and hydrogen skimmer system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff then reviewed the AMR results provided in Table 3.2-3 of the LRA to determine whether the applicant appropriately identified the components belonging to the containment air return exchange and hydrogen skimmer system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). In order to perform a conservative review, the staff focused on those components of the containment air return exchange and hydrogen skimmer system that were not identified as meeting the above requirements. The staff also reviewed Section 6.2 of the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted from Section 2.3.2.3 of the applicant's LRA.

As described in detail below, the staff questioned the applicant's omission from the scope of license renewal of certain ductwork (McGuire only) in the containment air return portion of this system. Additionally, the staff questioned the applicant's apparent omission from the scope of license renewal of the containment hydrogen recombiners, and the omission of certain piping in the hydrogen skimmer portion of the system. Finally, the staff questioned the applicant's omission of the fan bodies and damper bodies throughout the containment air return exchange and hydrogen skimmer system.

By letter dated January 23, 2002, the staff requested, in RAI 2.3.2.3-1, the applicant to indicate whether or not certain ductwork (McGuire only) performs the intended function of serving as a passive pressure boundary in the containment air return portion of this system. In its response dated April 15, 2002, the applicant stated that the ductwork identified by the staff, which is indicated on the piping and instrumentation diagrams for the McGuire containment air return system, does not physically exist at the plant. In actuality, the containment air return fans and dampers at McGuire are bolted together directly without intervening ductwork and mounted directly upon the floor of the upper containment. Therefore, staff finds the applicant's exclusion of containment air return ductwork from the scope of license renewal to be acceptable for McGuire.

By letter dated January 23, 2002, the staff also requested, in RAI 2.3.2.3-3, additional information to address the apparent omission of the containment hydrogen recombiners and any supporting mechanical components from the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the hydrogen recombiners are electrical (rather than mechanical) components, but that they were considered within the scope of license renewal for McGuire and Catawba. The applicant further stated that, in accordance with 10 CFR 50.49, the recombiners are included within the Environmental Qualification Program at each site, and, as they are subject to replacement based on a qualified lifetime, they are not subject to an AMR. The staff finds the applicant's response to be acceptable because (1) it is consistent with the regulatory guidance provided in the Standard Review Plan for License Renewal and the Generic Aging Lessons Learned Report, and (2) it indicates that the hydrogen recombiners are addressed in the Electrical and Instrumentation and Controls section of the LRA. The staff's evaluation of the Electrical and Instrumentation and Controls section is documented in Section 2.5 of this SER.

The staff asked why the non-safety-related carbon steel piping used to skim hydrogen from various containment compartments was not considered to be within the scope of license renewal for McGuire and Catawba. As documented in a telecommunication summary dated November 14, 2001, the applicant explained that the piping not highlighted was embedded in concrete, and that a breach of the embedded piping would not result in a loss of the intended pressure boundary function of the piping. The applicant stated that the surrounding concrete would alternately provide a hydrogen skimmer system flow-path, and that this concrete is a safety-related structure that is within the scope of license renewal and subject to an AMR. Although the staff recognizes that the gaseous permeability of concrete is greater than that of carbon steel, the staff finds the applicant's response to be satisfactory because reasonably postulated localized failures of the hydrogen skimmer system piping would not be expected to have a noticeable effect on the system's performance due to the relatively small differential pressures postulated between the hydrogen skimmer system and the ambient containment atmosphere, and to the high quality of the structural concrete used in the containment design. Although the applicant has not demonstrated that a complete disintegration of the embedded hydrogen skimmer system would not degrade the hydrogen skimmer system's performance, the staff does not consider complete disintegration to be a reasonably postulated failure because the secure and relatively benign internal and external environments for embedded carbon steel piping used in ventilation systems is not expected to promote rapid and undue aging effects. Therefore, the staff has concluded that (1) the applicant has appropriately addressed 10 CFR 54.4(a)(2) for the embedded piping in the hydrogen skimmer system, and (2) the applicant's response is consistent with the general information and descriptions provided in the LRA.

By letter dated January 23, 2002, the staff requested, in RAIs 2.3-1 and 2.3-2, additional information to determine whether fan and damper housings in the containment air return exchange and hydrogen skimmer system perform the intended function of serving as a passive pressure boundary. In its response dated April 15, 2002, the applicant indicated that fan and damper bodies for ventilation systems at McGuire and Catawba were not subject to an AMR due to specific exceptions stated in 10 CFR 54.21(a)(1)(i). The staff finds the applicant's response to be unacceptable because it interprets 10 CFR 54.21(a)(1)(i) in a manner that is contrary to the basis for this regulation. Although fans and dampers are considered to be active components, their bodies are passive structural components that perform an intended pressure boundary function (i.e., the pressure boundary provided by the fan bodies and damper bodies is necessary for the success of these components' associated active functions). Therefore, the staff considers that (1) all of the fan bodies and damper bodies that perform an intended pressure boundary function for the containment air return exchange and hydrogen skimmer system are within the scope of license renewal and subject to an AMR, and (2) the applicant's basis for excluding these fan bodies and damper bodies is not adequate since it inherently contradicts the requirements of 10 CFR 54.21(a)(1)(i). This issue was characterized as SER open item 2.3-1 (fan housings) and SER open item 2.3-2 (damper housings).

In its response to SER open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the containment air return exchange and hydrogen skimmer system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.2.3.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

2.3.2.3.3 Conclusions

With the resolution of SER open items 2.3-1 and 2.3-2 concerning the fan and damper housings in the containment air return exchange and hydrogen skimmer system, the staff concludes that, for both McGuire and Catawba, there is reasonable assurance that the applicant has appropriately identified the components of this system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

*2.3.2.4 Containment Spray System*

In Section 2.3.2.4 of the LRA, the applicant described the containment spray system (CSS) and the components therein which are within the scope of license renewal and subject to an AMR.

This system is further described in Section 6.5 of the McGuire UFSAR and Section 6.2.2 of the Catawba UFSAR.

### 2.3.2.4.1 Technical Information in the Application

The containment spray system is an ESF with the following three intended functions—(1) removing thermal energy from the post-accident containment atmosphere to help maintain containment pressure below its design value, (2) removing fission product iodine from the post-accident containment atmosphere, and (3) suppressing steam partial pressure in the upper containment volume from operating deck leakage due to a loss-of-coolant accident. The containment spray system consists of two redundant trains, each with a motor-driven pump, piping, a heat exchanger, two spray headers, and a residual heat removal (RHR) spray header.

Based on the three intended functions identified above, the applicant identified the following 10 component types of the containment spray system as within the scope of license renewal and subject to an AMR-flow orifices, heat exchanger channel heads, heat exchanger shells, heat exchanger tubes, heat exchanger tube sheets, piping, pump casings, spray nozzles, tubing, and valve bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the containment spray system pressure boundary, throttling flow, transferring heat, and/or inducing spray flow.

### 2.3.2.4.2 Staff Evaluation

The staff reviewed Section 2.3.2.4 of the LRA, and the associated piping and instrumentation diagrams, to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment spray system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff then reviewed the AMR results provided in Table 3.2-4 of the LRA to determine whether the applicant appropriately identified the components belonging to the containment spray system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). In order to perform a conservative review, the staff focused on those components of the containment spray system that were not identified as meeting the above requirements. The staff also reviewed Section 6.5 of the McGuire UFSAR, and Section 6.2.2 of the Catawba UFSAR, and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted from Section 2.3.2.4 of the applicant's LRA.

The applicant considered within the scope of license renewal all of the components of the containment spray system which support the performance of the system's three intended functions, including the unisolable portions of nonessential miscellaneous piping lines (e.g., fill, drain, and vent lines) connected to essential parts of the system. These unisolable portions do not serve any intended function other than maintaining the pressure boundary of the containment spray system. The staff finds this approach to be acceptable because it is consistent with the scoping criteria of 10 CFR 54.4. However, the staff questioned the applicant's omission of five capped drain and vent lines connected to the main containment spray discharge lines which were not highlighted as within the scope of license renewal on two of the containment spray system piping and instrumentation diagrams. As detailed in a telecommunication summary dated November 14, 2001, the applicant confirmed that these five capped piping lines were considered to be within the scope of license renewal and should have been highlighted. The staff finds the applicant's response satisfactory because (1) it is consistent with license renewal scoping regulation, 10 CFR 54.4, and (2) it is consistent with the general information and descriptions provided in the LRA concerning the containment isolation system.

2.3.2.4.3 Conclusions

The staff concludes that, for both McGuire and Catawba, there is reasonable assurance that the applicant has appropriately identified the components of the containment spray system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

*2.3.2.5 Containment Valve Injection Water System*

In Section 2.3.2.5 of the LRA, the applicant described the containment valve injection water system and the components therein which are within the scope of license renewal and subject to an AMR. This system is exclusive to Catawba and is further described in Section 6.2.4 of the Catawba UFSAR.

2.3.2.5.1 Technical Information in the Application

Catawba’s containment valve injection water system is an ESF with the intended function of injecting water at a pressure exceeding containment design peak pressure between the two seating surfaces of double-disc gate valves used for containment isolation. The containment valve injection water system thus helps reduce potential offsite dose consequences to less than the values specified in 10 CFR Part 100. The containment valve injection water system has two trains, each consisting of piping headers and a nitrogen-pressurized surge tank.

Based on the intended function identified above, for Catawba only, the applicant identified the following four component types of the containment valve injection water system as within the scope of license renewal and subject to an AMR-piping, tanks, tubing, and valve bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the containment valve injection water system pressure boundary.

2.3.2.5.2 Staff Evaluation

The staff reviewed Section 2.3.2.5 of the LRA, and the associated piping and instrumentation diagrams, to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the containment valve injection water system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff then reviewed the AMR results provided in Table 3.2-5 of the LRA to determine whether the applicant appropriately identified the components belonging to the containment valve injection water system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). To perform a conservative review, the staff focused on those components of the containment valve injection water system that were not identified as meeting the above requirements. The staff also reviewed Section 6.2.4 of the Catawba UFSAR and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted from Section 2.3.2.5 of the applicant’s LRA.

The applicant considered all essential portions of the containment valve injection water system as within the scope of license renewal. However, the staff noted that two segments of piping did not appear to be highlighted correctly on one of the containment valve injection water system piping and instrumentation diagrams. As detailed in a telecommunication summary dated November 14, 2001, the applicant confirmed that these two segments of piping were considered to be within the scope of license renewal and should have been highlighted. The staff finds the applicant's response satisfactory because it is consistent with 10 CFR 54.4, and notes that the additional information provided by the applicant is consistent with the general information and descriptions of the containment valve injection water system provided in the LRA.

2.3.2.5.3 Conclusions

The staff concludes that there is reasonable assurance that the applicant has appropriately identified the components of Catawba's containment valve injection water system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

*2.3.2.6 Refueling Water System*

In LRA Section 2.3.2.6, "Refueling Water System," the applicant described the components of the refueling water system that are within the scope of license renewal and subject to an AMR. Section 9 of the Catawba and McGuire UFSARs provides additional information concerning their respective refueling water systems.

2.3.2.6.1 Technical Information in the Application

The Catawba refueling water system provides an adequate supply of borated water to the emergency core cooling system (ECCS) and containment spray system in order to mitigate the consequences of a design basis event. The refueling water system, safety injection system, residual heat removal system, and chemical and volume control system (CVCS) together form the ECCS.

The McGuire refueling water system provides a source of borated water to be used during refueling for the ECCS to mitigate the consequences of a UFSAR Chapter 15 accident or as borated makeup water for the spent fuel pool (SFP). The system can remove impurities from the refueling cavity and transfer canal during refueling, and it can clean up the refueling water storage tank (RWST) water following refueling. This can be accomplished by routing flow through the purification loop of the spent fuel pool cooling system. The refueling water system provides a means of transferring the final 30 percent of the refueling water between the refueling cavity and the refueling water storage tank. It also provides a secondary means of filling the refueling cavity from the refueling water storage tank.

Using the methodology described in LRA Section 2.1.2, "Screening Methodology," the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to AMR, their intended functions, and materials of construction for the refueling water system are listed in Table 3.2-6 of the LRA. In LRA Table 3.2-6, the applicant lists the following four component commodity groups as subject to an AMR-pipe, refueling water storage tank, tubing, and valve bodies. LRA Table 3.2-6 also lists expansion joints as a component type that is subject to an AMR only for the McGuire refueling water system. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

2.3.2.6.2 Staff Evaluation

The staff reviewed Section 2.3.2.6 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the refueling water system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.2.6 of the LRA and Section 9 of the Catawba and McGuire UFSARs to determine if the applicant adequately identified the SSCs of the refueling water system that are in the scope of license renewal. The staff verified that those portions of the refueling water system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.2.6 of the LRA. The staff then focused its review on those portions of the refueling water system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the refueling water system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to AMR for the refueling water systems in Table 3.2-6 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determined were within the scope of license renewal but not subject to AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the refueling water system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believed perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the refueling water system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4.

During its review, the staff identified several potential discrepancies in the drawings used by the applicant to show which refueling water system components for both Catawba and McGuire are within the scope of license renewal. The discrepancies were that components that should have been shown as within the scope of license renewal were not appropriately marked. By letter dated January 23, 2002, the staff requested, in RAIs 2.3.2.6-2 and 2.3.2.6-3, clarification from the applicant. In its responses dated April 15, 2002, the applicant stated that the components in question were within the scope of license renewal and the drawings had been improperly marked. Based on the above, the staff finds the applicant's responses acceptable.

One of the McGuire refueling water system drawings for Unit 2, MCFD-2571-01.00, shows that the refueling cavity is within the scope of license renewal. The equivalent drawings for McGuire 1 and both Catawba units indicate that the refueling cavity is not with the scope of license renewal. In addition, the refueling cavity is not listed in Table 3.2-6, "Aging Management Review Results - Refueling Water System." The UFSARs for both Catawba and McGuire credit the refueling cavity walls as protecting vital equipment and components from the dynamic effects of a postulated pipe break. Accordingly, the staff believed the refueling cavity should be within the scope of license renewal. By letter dated January 23, 2002, the staff requested, in RAI 2.3.2.6-1, the applicant to explain why this component was not highlighted as within scope. In its response dated April 15, 2002, the applicant stated that the refueling cavity is a structural component, and it is within the scope of license renewal. According to the applicant, structural components are not normally shown on flow diagrams, but where they are, the structural components are not addressed by the highlighting conventions. The applicant also stated that AMR results for the refueling cavity are located in Table 3.5-1 of the LRA. Based on the above, the staff finds the applicant's response acceptable.

During its review, the staff identified a potential discrepancy in the drawings used by the applicant to show the minimum-flow piping for the safety injection pumps. The drawings showed that the non-safety-related portion of minimum-flow piping from the isolation valve to the RWST was not within the scope of license renewal. The staff was concerned that the failure of that piping could prevent the minimum-flow piping from performing its function and result in damage to the safety injection pump. By letter dated January 23, 2002, the staff requested, in RAI 2.3.2.6-5, the applicant to explain why this piping was not indicated as within scope. In its response dated April 15, 2002, the applicant stated that the non-safety-related portions of the minimum-flow piping were not within the scope of license renewal because they did not support any safety injection system intended function. The applicant also stated that a loss of pressure boundary of the non-safety-related portion of the minimum-flow piping did not adversely affect the ability of the safety injection pump to achieve minimum recirculation flow. Because failure of the non-safety-related portions of the minimum flow piping would not prevent the safety-related portion of the safety injection pump from performing its intended function, the staff concludes that the minimum flow piping is outside the scope of license renewal.

#### 2.3.2.6.3 Conclusions

On the basis of its review of the information contained in Section 2.3.2.6 of the LRA, the supporting information in the Catawba and McGuire UFSARs, as described above, and the response to the staff's RAI, dated April 15, 2002, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the refueling water system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.2.7 Residual Heat Removal System*

#### 2.3.2.7.1 Technical Information in the Application

<u>McGuire Nuclear Station</u>

As described in the LRA, the RHR system transfers heat from the reactor coolant system to the component cooling system to reduce the temperature of the reactor coolant to the cold-shutdown temperature at a controlled rate during the second part of unit cooldown, and maintains this temperature until the unit is started up. The RHR system also serves as part of the emergency core cooling system during the injection and recirculation phases of small-break and large-break loss-of-coolant accidents.

<u>Catawba Nuclear Station</u>

The RHR system transfers heat from the reactor coolant system to the component cooling system to reduce the temperature of the reactor coolant to the cold-shutdown temperature at a controlled rate during the second phase of unit cooldown, and maintains this temperature until the unit is started up. The RHR system also serves as part of the emergency core cooling system during the injection and recirculation phases of design basis events. The RHR system has several secondary functions, which include transferring refueling water between the refueling water storage tank and the refueling cavity before and after refueling operations, providing overpressure protection to the reactor coolant system, providing reactor coolant letdown flow for pressure control and purification during shutdown and refueling, and providing residual heat removal auxiliary pressurizer spray.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba RHR systems are listed in Table 3.2-7 of the LRA. The component types that were identified in the table include heat exchanger (tubes, tube sheet, channel head, and shell), RHR pump seal water (tubes and shell), heat exchanger RHR pump seal water (cover) (Catawba only), orifices, pipe, pump casings, tubing, and valve bodies. The applicant further noted in the table that the intended functions of these components are maintaining the integrity of the residual heat removal system pressure boundary, transferring heat, and throttling flow.

#### 2.3.2.7.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the RHR components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the portions of the McGuire and Catawba UFSARs relevant to the RHR system and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). The staff also reviewed the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted by the applicant.

The Catawba UFSAR (page 5.4-48) states that “a minimum number of charging auxiliary spray has been included in the piping analysis for inadvertent operation and for emergencies.” Also the McGuire UFSAR (page 9.3-25) states that “after the Residual Heat Removal System is placed in service and the reactor coolant pumps are shut down, further cooling of the pressurizer liquid is accomplished by charging through the auxiliary spray line.” If these statements imply that auxiliary spray is relied upon to mitigate design-basis events, or is relied on in safety analyses or plant evaluations to perform a function that is required by the regulations governing fire protection and station blackout, then the staff believes that the applicant should explain why the spray head (the component which actually sprays the water inside the pressurizer) does not require aging management to detect cracking and/or clogging of the spray holes, or any other age-related degradation over the extended period of operation. The staff requested, in RAI 2.3.2.7-1, that the applicant determine whether the intended function of the pressurizer spray head to depressurize the reactor coolant system is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) or (3). The staff requested confirmation that the spray head is not credited for immediate pressure reduction during design basis events, postulated fire events, or station blackout. In its response dated April 15, 2002, the applicant provided the following—

> Auxiliary spray is not relied upon to mitigate design basis events or to demonstrate compliance with requirements associated with Station Blackout. However, Auxiliary spray is used during the transition between Hot Shutdown (Mode 4) and Cold Shutdown (Mode 5) in order to achieve cold shutdown following a postulated fire in the plant pursuant to the requirements of §50.48. The pressurizer spray head is a full cone center jet nozzle with a flow opening that is approximately three inches in diameter at both McGuire and Catawba Nuclear Stations. The spray nozzle does not resemble a shower head, therefore clogging of spray holes is not a potential aging effect. Cracking of the spray head due to either (1) stress corrosion cracking or (2) reduction in fracture toughness (due to thermal embrittlement) of the cast austenitic stainless steel (CASS) is a potential aging effect. Stress corrosion cracking is managed by the Chemistry Control Program. The Chemistry Control Program is described in Appendix B.3.6 of the Application. Uncertainty exists as to whether reduction in fracture toughness could manifest itself to the point where cracking could occur. Gross cracking and structural damage would be required for the spray head to function improperly. Because of this uncertainty, Duke commits to perform a one time inspection of the pressurizer spray head on one unit as described below to assess the condition of the spray head regarding cracking. The details of the Pressurizer Spray Head Examination follow.

Table 3.[1*]-1 of the Application is supplemented with the following information—

| Component Type | Component Function | Material | Environment | Aging Effect | Aging Management Programs and Activities |
|---|---|---|---|---|---|
| [**Pressurizer***] | | | | | |
| Pressurizer Spray Head | Spray | Cast Stainless Steel | Borated Water | Cracking | Chemistry Control Program<br><br>Pressurizer Spray Head Examination |

[* corrections were made by the staff to reflect the correct table and component]

Pressurizer Spray Head Examination

Note: The Pressurizer Spray Head Examination is generically applicable to both McGuire Nuclear Station and Catawba Nuclear Station, except as otherwise noted.

The purpose of the Pressurizer Spray Head Examination is to characterize any cracking of the spray head due to reduction in fracture toughness (due to thermal embrittlement) of the cast austenitic stainless steel (CASS) in the environment of the pressurizer steam space. Uncertainty exists as to whether exposure of the CASS spray head in this environment could result in cracking such that the spray head spray function could become degraded or completely lost during the period of extended operation. This examination will visually inspect one spray head for cracking. The Pressurizer Spray Head Examination is a one-time-inspection.

Duke plans to inspect the operating unit with the most hours at operating temperature among the four units at McGuire and Catawba. McGuire Unit 1 is expected to be the lead unit for this inspection since it is expected to have the most hours of operation among the four units at McGuire and Catawba. After the results of the McGuire Unit 1 inspection are evaluated, additional examinations may be performed on the spray heads at McGuire Unit 2 and Catawba Units 1 and 2.

[Scope] The scope of the Pressurizer Spray Head Examination is the internal spray heads of the McGuire and Catawba pressurizers.

[Preventive Actions] No actions are taken as part of this program to prevent aging effects or mitigate aging degradation.

[Parameters Monitored of Inspected] The parameter inspected by the Pressurizer Spray Head Examination is cracking of the pressurizer spray head due to reduction in fracture toughness (thermal embrittlement).

[Detection of Aging Effects] The Pressurizer Spray Head Examination is a one-time inspection and will detect the presence of cracking of the pressurizer spray heads.

[Monitoring & Trending] The Pressurizer Spray Head Examination is a visual examination (VT-3) of the pressurizer spray head. No actions are taken as part of this program to trend inspection or test results.

For McGuire, this new inspection will be completed following issuance of renewed operating licenses for McGuire Nuclear Station and by June 12, 2021 for McGuire Unit 1. Any required inspection of the Unit 2 pressurizer spray head will be completed following issuance of renewed operating licenses for McGuire Nuclear Station and by March 3, 2023 for McGuire Unit 2.

For Catawba, if necessary following the results of the McGuire Unit 1 examination, this new inspection will be completed following issuance of renewed operating licenses for Catawba Nuclear Station by December 6, 2024 for Catawba Unit 1 and by February 24, 2026 for Catawba Unit 2.

[Acceptance Criteria] The acceptance criterion for Pressurizer Spray Head Examination will be in accordance with ASME Section XI, VT-3 examinations.

[Corrective Action & Conformation Process] If the results of the inspection do not meet the specified acceptance criterion, then corrective actions will be taken such as replacing the affected spray heads. If cracks are detected in the initial spray head visual examination, then visual examinations will be conducted on the spray heads for McGuire Unit 2 and Catawba Units 1 and 2. Specific corrective actions and confirmation are implemented in accordance with the corrective action program.

[Administrative Controls] The Pressurizer Spray Head Examination will be implemented by plant procedures and the work management system.

[Operating Experience] The Pressurizer Spray Head Examination is a new inspection for which there is not operating experience. However, a similar inspection was reviewed and deemed acceptable by the NRC staff for Oconee, as stated in the conclusions below.

> Conclusion - The Pressurizer Spray Head Examination is similar to the corresponding Pressurizer Examination described and evaluated in NUREG-1723. Based on the above review, the implementation of the Pressurizer Spray Head Examination will ensure the pressurizer spray head will continue to perform its intended function for the period of extended operation.
>
> The McGuire and Catawba UFSAR Supplements will be revised to include the above mentioned summary description of the Pressurizer Spray Head Examination.

The staff agrees with the applicant's conclusion that the pressurizer spray head is within the scope of license renewal and is subject to an AMR. The staff's evaluation of the proposed aging management programs and activities for the pressurizer spray head, as presented above, is documented in Section 3.1.2.2 of this SER.

2.3.2.7.3 Conclusions

On the basis of its review of the information presented in Section 2.3.2.7 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant's response to the requests for additional information, the staff determined that the applicant did not include the pressurizer spray head of the auxiliary spray system as within the scope of license renewal and subject to an AMR for McGuire and Catawba. However, the applicant subsequently added the pressurizer spray head to the scope of components subject to an AMR. No additional omissions were identified. Therefore, the staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the RHR and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

*2.3.2.8 Safety Injection System*

2.3.2.8.1 Technical Information in the Application

The SIS constitutes a major portion of the emergency core cooling system. Along with the RHR, chemical and volume control, and refueling water systems, the SIS provides emergency cooling to the reactor core in the event of a break in either the primary (reactor coolant) or secondary (steam) systems. The three primary functions of the emergency core cooling system are (1) removing stored (sensible) and fission product decay heat, (2) controlling reactivity, and (3) precluding reactor vessel boron precipitation. The SIS supports each of these functions.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba SISs are listed in Table 3.2-8. The component types that were identified in the table include orifices, pipe, cold-leg accumulators, pump casings, tubing, and valve bodies. The applicant further noted in the table that the intended functions of these components are maintaining the integrity of the safety injection system pressure boundary and throttling flow.

2.3.2.8.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the SIS and associated pressure boundary components and supporting structures, within the scope of license renewal and subject to AMR, have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the portions of the McGuire and Catawba UFSARs relevant to the SIS and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). The staff also reviewed the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted by the applicant.

The UFSARs for Catawba (page 6.2-46) and McGuire (page 17.1-2), state that screen assemblies and vortex suppressors are used in the containment sump, which provides water for the ECCS recirculation phase, and one of the intended functions is to protect the ECCS pumps from debris and cavitation due to harmful vortex following an LOCA. The staff noted that the sump screens were identified in Table 3.5-1, “AMR Results - Reactor Building” however, the vortex suppressors were not identified in the LRA as within scope and requiring an AMR. By letter dated January 23, 2002, the staff requested, in RAI 2.3.2.8-1, the applicant to explain the reason for the omission. In its response dated April 15, 2002, the applicant explained that the vortex suppressor is a subcomponent of the recirculation intake sump screen assembly, is subject to an AMR, and is addressed in Table 3.5-1 (page 3.5-9, row 3) of the LRA. Each sump screen assembly consists of filtering screen panels which surround the recirculation lines intake and extend to the floor. The screen panels consist of vortex suppressor grates, which prevent local vortex disturbances and large debris from reaching the inner fine screen. The inner fine screen prevents particles that are large enough to impair ECCS or containment spray performance from being drawn into these systems. UFSAR Figures 6-111 (Catawba) and 6-196 (McGuire) provide diagrams of the containment sump assemblies (including vortex suppressors). This above clarification is acceptable, and the staff did not identify any omissions.

2.3.2.8.3 Conclusions

On the basis of its review of the information presented in Section 2.3.2.8 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant’s response to the RAI, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the SIS and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

*2.3.2.9 Miscellaneous Instrumentation System*

In its April 15, 2002, response to RAI 2.3.2.3-2, the applicant described the miscellaneous instrumentation system at McGuire and Catawba, and the components therein, which are within the scope of license renewal and subject to an AMR. The applicant had inadvertently omitted this system from the scoping and AMR screening review submitted in the LRA.

2.3.2.9.1 Technical Information in the Application

The mechanical components of the miscellaneous instrumentation system support the following three components or systems (1) the safety-related containment hydrogen analyzers, (2) the containment integrated leakage rate testing system, and (3) the containment radiation monitors. The intended function of the safety-related hydrogen analyzers is to provide the capability for monitoring the hydrogen concentration within the containment at three different locations following a postulated accident. The intended function of the mechanical components supporting the integrated leakage rate testing system and containment radiation monitors is to isolate the non-essential containment penetrations serving these components to prevent the uncontrolled or unmonitored release of radioactivity to the environment.

Based on the intended functions identified above, the applicant identified the following three component types of the miscellaneous instrumentation system as within the scope of license renewal and subject to an AMR-valve bodies, tubing, and piping (McGuire 1 only). The applicant further identified the intended functions of these component types as maintaining the integrity of the miscellaneous instrumentation system pressure boundary.

2.3.2.9.2 Staff Evaluation

The staff reviewed RAI Response 2.3.2.3-2, dated April 15, 2002, to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the miscellaneous instrumentation system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff then reviewed the LRA table of AMR results included with the applicant's response to RAI 2.3.2.3-2 to determine whether the applicant appropriately identified the components belonging to the miscellaneous instrumentation system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). In order to perform a conservative review, the staff focused on those components of the miscellaneous instrumentation system that were not identified as meeting the above requirements. The staff also reviewed the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted by the applicant.

The applicant considered the safety-related hydrogen analyzers and their supporting mechanical components to be within the scope of license renewal. The hydrogen analyzers employ an electrochemical process and, as their functioning involves a change of state, are not subject to an AMR. However, the applicant identified that the tubing and valve bodies which connect the containment atmosphere to the hydrogen analyzers are passive, long-lived components subject to an AMR. For the containment integrated leakage rate testing system and the containment radiation monitors, the applicant considered only the safety-related valve bodies, tubing, and piping used for containment isolation to be within the scope of license renewal and subject to an AMR. As the integrated leakage rate testing system and containment radiation monitors are not otherwise relied upon to satisfy assumptions made in the safety analyses for McGuire or Catawba, the staff finds the applicant's approach acceptable.

2.3.2.9.3 Conclusions

The staff has concluded that, for both McGuire and Catawba, there is reasonable assurance that the applicant has appropriately identified the components of the miscellaneous instrumentation system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

### 2.3.3 System Scoping and Screening Results: Auxiliary Systems

In Section 2.3.3, “Auxiliary Systems,” of the McGuire and Catawba LRA, the applicant described the SSCs of the auxiliary systems that are subject to an AMR for license renewal.

#### *2.3.3.1 Auxiliary Building Ventilation System*

In LRA Section 2.3.3.1, “Auxiliary Building Ventilation System,” the applicant identified portions of the auxiliary building ventilation (VA) system and the components that are within the scope of license renewal and subject to an AMR. In this section of the LRA, the applicant stated that the VA system is further described in McGuire UFSAR Section 9.4.2 and Catawba UFSAR Section 9.4.3.

The applicant evaluated component supports for VA system ductwork within Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the systems in Section 2.1.2 of the LRA. The staff’s scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff’s evaluation of electrical components and instrumentation and controls in the VA system is documented in Section 2.5 of this SER.

##### 2.3.3.1.1 Technical Information in the Application

The VA system automatically aligns to maintain the ECCS pump rooms at a negative pressure, with respect to the adjacent areas, so that effluent from these rooms is filtered prior to being released to unit vents following a design basis accident. The ECCS pump rooms include the safety injection pumps, residual heat removal pumps, centrifugal charging pumps, and containment spray pumps.

The VA system serves all areas of the auxiliary building with the exception of the control room and fuel handling areas. Ventilation air is supplied to both clean and potentially contaminated areas of the auxiliary building. Control of airborne activity is accomplished by exhausting air supplied to clean areas through the potentially contaminated areas. This air in turn is processed by the filtered exhaust subsystem. This provides a positive flow of air from clean areas to areas of potential contamination. The remaining air supplied to clean areas is exhausted by the unfiltered exhaust subsystem. All air exhausted from the auxiliary building, both filtered and unfiltered, is directed to the unit vent. Exhaust air is monitored for radiation prior to an atmosphere release.

During normal operation, the VA system supply and exhaust fans are automatically stopped upon indication of high radiation level in the unit vent. Upon receipt of an ESF actuation signal, all VA system components automatically stop. The filtered exhaust subsystems have two separate and redundant trains. The filtered exhaust subsystem automatically cycles on with emergency Class 1E standby power. With the exception of the ECCS pump rooms, all areas of the auxiliary building are automatically isolated from the filtered exhaust system.

In Section 2.3.3.1 of the LRA, and Sections 9.4.2 and 9.4.3 of the McGuire and Catawba UFSARs, respectively, the applicant identified the following intended functions of the McGuire and Catawba VA systems based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

<u>McGuire</u>

Section 2.3.3.1 of the LRA—

- to automatically align to maintain the ECCS pump rooms at a negative pressure so that air exhausted from these rooms is filtered prior to being released following a DBA

Section 9.4.2 of the UFSAR—

- to maintain a suitable environment for the operation of equipment and personnel access as required for inspection, testing, and maintenance
- to hold the auxiliary building at a slightly negative pressure to minimize outleakage
- to purge the auxiliary building to the unit vent. The air that is exhausted to the environment from potentially contaminated areas is monitored and filtered so that the limits of 10 CFR Part 20 and the technical specifications are not exceeded
- provide a suitable environment for the operation of vital equipment during an accident

<u>Catawba</u>

Section 2.3.3.1 of the LRA—

- to automatically align and maintain the ECCS pump rooms at a negative pressure so that air exhausted from these rooms are filtered prior to release following a design basis accident

Section 9.4.3 of the UFSAR—

- to maintain a suitable environment for the operation, maintenance, and testing of equipment
- to maintain a suitable environment for personnel access
- to minimize the release of radioisotopes from the ECCS pump rooms during accident conditions

On the basis of the intended functions identified above for the VA systems, the portions of these systems that were identified by the applicant as within scope include all VA system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1.2 of the LRA. On the basis of this methodology, the applicant identified the portions of the VA system that are within the scope of license renewal on the flow diagrams listed in Section 2.3.3.1 of the LRA. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 3.3-1 of the LRA.

The following component types are identified in Table 3.3-1 of the LRA as within the scope of license renewal and subject to an AMR-airflow monitors, ductwork, filters, tubing, valve bodies, air handling units (Catawba only), air handling units - tubes and plenum assembly (McGuire only), and heaters (Catawba only). In Table 3.3-1 of the LRA the applicant noted that the VA system pressure boundary and heat exchanger functions are the only applicable intended functions of VA system components subject to an AMR.

#### 2.3.3.1.2 Staff Evaluation

To verify that the applicant identified the components of the VA system within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagrams listed in Section 2.3.3.1 of the LRA showing the evaluation boundaries for the highlighted portion of the VA system within the scope of license renewal, and Table 3.3-1 of the LRA, which lists the mechanical components and applicable intended functions subject to an AMR. The staff also reviewed Sections 9.4.2 and 9.4.3 of the McGuire and Catawba UFSARs, respectively, to determine if there were any portions of the VA system that met the scoping criteria in 10 CFR 54.4(a) but were not identified as being within the scope. The staff reviewed the UFSAR also to determine if there were any safety-related system functions that were not identified as intended functions in the LRA, and if there were any structures or components that have an intended function that might have been omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSAR to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VA system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-1 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled structures and components from Table 3.3-1 of the LRA to verify that the applicant identified the structures and components subject to an AMR. The staff also sampled the structures and components that are within the scope of license renewal but not subject to an AMR. Based on the sample, the staff verified that these structures and components perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VA system excluded from scope do not perform any intended functions, the staff determined that additional information was needed to clarify information in the UFSAR and LRA. The staff noted that LRA Section 2.3.3.1 presents a summary description of the system functions and a listing of flow diagrams. The flow diagrams highlight the evaluation boundaries, and Table 3.3-1 of the LRA tabulates the components within the scope of license renewal and are subject to an AMR for the VA system. However, the corresponding drawings and information in the UFSAR indicate that additional components were not listed in Table 3.3-1 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of fan housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant goes on to state that those cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant's basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within the scope of license renewal. Furthermore, because the fan housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-2, specific information concerning the exclusion of damper housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that dampers are not included in the AMR result tables in the LRA. The applicant added that ventilation dampers, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope of license renewal. Furthermore, because the damper housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the auxiliary building ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.1.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-3, specific information concerning the exclusion of housings for radiation monitors, smoke detectors, and air flow monitors from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that, based on guidance provided in NEI 95-10, Revision 3, radiation monitors, smoke detectors, and chlorine detectors are not considered passive components and are therefore not subject to an AMR. Because these monitors and detectors do not perform an intended function as defined in 10 CFR 54.4, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-4, specific information concerning the exclusion of building sealants from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that it does not classify materials such as sealants to be structures or components. The applicant stated the pressure boundary function is addressed by TS surveillance testing. However, the applicant did not indicate that any of the TS surveillance requirements listed in its response were credited for aging management (and identified as AMPs). Nor did the applicant furnish a description of, or information pertaining to, a TS surveillance AMP (including discussion of the 10 elements of the AMP) for the staff's review.

On page 2.1-24 of the LRA, the applicant stated that "seals associated with maintaining pressure boundary are limited to the divider barrier seals in the reactor building." Since the applicant does not discuss the treatment of structural sealants other than the divider barrier seal, it is not clear to the staff that building (structural) sealants were considered during an AMR of the structure (building) for which they are a subcomponent. Furthermore, according to page 3.5-10 of the LRA, the Inspection Program for Civil Engineering Structures and Components is credited by the applicant to monitor the aging of building concrete structural components (reinforced concrete beams, columns, floor slabs, and walls). According to Section B.3.21, of Appendix B of the LRA, the scope of the Inspection Program for Civil Engineering Structures and Components does not include structural sealants. Table 2.1-3, on page 2.1-15 of the SRP-LR, states that an applicant's structural AMP is expected to address structural sealants "with respect to an AMR program." The intent of this statement is that an applicant's structural AMP is expected to manage or monitor the aging effects of the structure and associated sub-components that are identified during the AMR. The basis for this SRP guidance is documented in the summary (issued January 21, 2000) of a December 8, 1999, meeting to discuss the staff's position on the treatment of consumables. This summary clearly states, on page 3, that structural sealants would be implicitly included at the component level and considered during the AMR. Since the structural AMP identified for the concrete structural components does not address structural sealants, and since that applicant did not identify the TS surveillances listed in its response as AMPs or provide appropriate information to support the staff's review of these surveillances as AMPs, the staff characterized this issue as SER open item 2.3-3.

In its response to this open item, dated October 28, 2002, the applicant credited a visual inspection of the structural sealant used to maintain ventilation pressure boundary integrity of the control room area, emergency core cooling pump rooms, annulus, and fuel handling building. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open item 2.3-3. The staff's evaluation of the Ventilation Area Pressure Boundary Sealants Inspection Program is provided in Section 3.0.3.19 of this SER.

By letter dated January 23, 2002, the staff requested, in RAIs 2.3-5 and 2.3-7(4), specific information concerning the exclusion of passive components associated with ductwork from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified these passive components as subcomponents of ductwork. The applicant also stated that ventilation grilles were installed only for aesthetic purposes and perform no intended license renewal function. Because the components serve only an aesthetic purpose and perform no intended function, the staff concludes they are outside the scope of license renewal.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-7(1), specific information concerning the exclusion of passive components associated with moisture eliminators from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant clarified the highlighting and identified moisture eliminators as subcomponents subject to an AMR. On the basis of the information provided, the staff finds the applicant's response acceptable.

Some components that are common to many systems, including the VA system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this report, the staff evaluated component supports for piping, cables, and equipment that supported the design and operation of the VA system. In Section 2.5 of the LRA titled, "Scoping and Screening Results: Electrical and Instrumentation and Controls," the staff evaluated electrical and instrument components that support the operation of the VA system.

The staff reviewed the LRA, supporting information in the UFSARs, and the applicant's responses to RAIs. In addition, the NRC staff sampled several components from the VA system flow diagram, as identified in LRA Section 2.3.3.1 to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

2.3.3.1.3 Conclusions

On the basis of its review, and with the resolution of open items identified in this SER section, the staff has reasonable assurance that the applicant has adequately identified the VA system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.2 Boron Recycle System*

2.3.3.2.1 Technical Information in the Application

McGuire Nuclear Station-As described in the LRA, the boron recycle system receives borated effluent from the reactor coolant system and associated support systems. This borated effluent is demineralized, filtered, and separated into 4 weight percent boric acid and reactor makeup water for reuse. The boron recycle system also provides reactor grade flush water for components in the auxiliary and reactor buildings.

Catawba Nuclear Station-The boron recycle system receives and recycles reactor coolant effluent for reuse of the boric acid and makeup water. The system decontaminates the effluent by means of demineralization and gas stripping, and uses evaporation to separate and recover the boric acid and makeup water. Portions of the boron recycle system are shared between both reactor units, while other portions are unit specific.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba boron recycle system are listed in Table 3.3-2 of the LRA. The component types that were identified in the table include eductors (McGuire only), filters, flow meters, orifices (Catawba only), pipe, recycle evaporative feed demineralizers, recycle holdup tanks, strainers (Catawba only), tubing, and valve bodies. The applicant further noted in the table that the only intended function of these components is maintaining the integrity of the boron recycle system pressure boundary, transferring heat and throttling flow.

2.3.3.2.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the boron recycle system components and supporting structures within the scope of license renewal and subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba on the boron recycle system and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have an applicable intended function(s), the staff sought to verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). The staff also reviewed the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted by the applicant.

The staff did not identify any omissions.

2.3.3.2.3 Conclusions

On the basis of its review of the information presented in LRA Section 2.3.3.2 and the supporting information in the McGuire and Catawba UFSARs, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the boron recycle system and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

*2.3.3.3 Building Heating Water System*

In LRA Section 2.3.3.3, “Building Heating Water System,” the applicant described the components of the McGuire heating water system and the Catawba building heating water system that are within the scope of license renewal and subject to an AMR. For simplification, the systems will be referred to as the building heating water system for both McGuire and Catawba when addressing common review attributes. The staff reviewed the LRA for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.3.1 Technical Information in the Application

The McGuire Nuclear Station heating water system satisfies normal heating requirements of the auxiliary building ventilation system, fuel pool ventilation system, containment and incore instrumentation room purge system, service building ventilation system, and the turbine building heating system. The Catawba Nuclear Station building heating water system supplies hot water to the heating coils of various HVAC units throughout the plant.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology,” and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2, “Screening Methodology.” Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively. The McGuire heating water system is listed on page 2.2-3 of LRA Table 2.2-1. The Catawba building heating water system is listed on page 2.2-7 of LRA Table 2.2-2.

The LRA notes that the only portions of the building heating water system subject to an AMR are the Duke Class F portions of the building heating water system that are in scope at Catawba and McGuire. Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the McGuire and Catawba mechanical components that are subject to an AMR in Table 3.3-3, "Aging Management Results - Building Heating Water System." This table also lists the intended function of each component and the materials of construction. The applicant identified the following components from the building heating water system that are subject to an AMR—pipes and valve bodies. The applicant identified maintaining pressure boundary integrity as the only intended function of the SCs subject to an AMR.

2.3.3.3.2 Staff Evaluation

The staff reviewed Section 2.3.3.3 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the building heating water system that are within the scope of license renewal in accordance with 10 CFR 54.4 and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.3 of the LRA and the applicable piping and instrument drawings referenced therein to determine if the applicant adequately identified the portions of the building heating water system that are within the scope of license renewal. The building heating water system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). The applicant included all components within the seismically designed piping boundaries of this system within the scope of license renewal per 10 CFR 54.4(a)(2). The staff verified that those portions of the building heating water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were identified by the applicant in LRA Section 2.3.3.3. To verify that the applicant did include the applicable portions of the building heating water system within the scope of license renewal, the staff focused its review on those portions of the building heating water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4.

During its review of Catawba drawings CN-1606-1, CN-1606-1.6, CN-1606-1.7, CN-1606-1.8, and CN-1606-1.9, the staff observed that the boundaries end in segments of pipe that are non-isolable and did not appear to coincide with structural boundaries (e.g., building walls). By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.3-1, why the termination of Class F piping depicted on the license renewal drawings was at locations other than building walls or valves for the Catawba building heating water system. In its response dated April 15, 2002, the applicant noted that for the building heating system, it was determined that only loss of pressure boundary in the large-diameter piping in the auxiliary building is a concern for flooding. Therefore, the small-diameter piping and the piping in the turbine building is not designated as Class F. The piping class breaks occur at the branch line tees and at the auxiliary building/turbine building wall. The applicant stated that the piping class breaks on the flow diagram are misleading. On drawing CN-1606-1.0, the class break is shown at a flange inside the auxiliary building. Applicant review of layout drawings indicated that the class break occurs on the turbine building side of the auxiliary building/turbine building wall. Of the other locations questioned by the staff on the remaining flow diagrams, the applicant review of layout drawings indicated that the class break occurs at the branch line tees, although the flow diagrams indicate the class break is some distance down the small-diameter piping. The applicant entered a corrective action report into the corrective action program to clarify the flow diagrams. The applicant confirmed that the piping and valves associated with the Class F portions of these lines are contained in LRA Table 3.3-3. Notwithstanding the clarification of the boundaries on the Catawba LRA drawings discussed above, the staff did not identify any omissions in the applicant's scoping review.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the building heating water system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the building heating water system in Table 3.3-3 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER.

The applicant identified the portions of the building heating water system that are within the scope of license renewal by drawings referenced in LRA Section 2.3.3.3. In addition, the applicant lists the pipe and valve body mechanical component commodity groups that are subject to an AMR and their intended function(s) in Table 3.3-3 of the LRA.

The license renewal drawings were highlighted by the applicant to identify those portions of the building heating water system meet at least one of the scoping criteria of 10 CFR 54.4. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement on the basis of qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions.

2.3.3.3.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.3 of the LRA and the LRA drawings, the staff did not identify any omissions in the scoping of the building heating water system by the applicant. The staff concludes that there is reasonable assurance that the applicant has identified those portions of the McGuire heating water system and the Catawba building heating water system that are within the scope of license renewal, and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.4 Chemical and Volume Control System*

2.3.3.4.1 Technical Information in the Application

The CVCS is an integral part of the emergency core cooling system and provides high-pressure injection and recirculation of borated water to the reactor coolant system cold legs following small-break and large-break loss-of-coolant accidents, and main steam line breaks. The CVCS is also used to provide negative reactivity to the core by boron injection.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba CVCSs are listed in Tables 3.3-4 and 3.3-5 of the LRA, respectively. The component types that were identified in the tables include blenders, pump casings, filters, tanks, meters, demineralizer-resin traps (McGuire only), demineralizers, heat exchangers-channel head, tube sheet, tubes, shell and interconnecting piping, meters - turbine meters (McGuire only), orifices, pipe, accumulators-non-wetted and wetted (McGuire only), stabilizers (McGuire only), spray nozzles (volume control tank), strainer (Catawba only), dampeners-non-wetted and wetted (McGuire), tubing, valve bodies, and dampeners-bellows exterior and interior (Catawba only). The applicant further noted in these table that the intended functions of these components are maintaining the integrity of the CVCS pressure boundary, throttling and filtering flow, and inducing spray flow.

2.3.3.4.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the CVCS, and associated pressure boundary components and supporting structures within the scope of license renewal and subject to an AMR, have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the CVCS and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have applicable intended functions, the staff sought to verify that they either perform these functions with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). The staff also reviewed the McGuire and Catawba UFSARs and did not identify any intended system functions meeting the scoping criteria in 10 CFR 54.4 that were omitted by the applicant.

On November 14, 2001, after completing the initial review, the staff and applicant participated in a conference call to clarify information presented in the LRA pertaining to scoping of certain components. During the conference call, the staff noted that CVCS flow diagram CN-1554-1.6 indicates that the piping from isolation valve 1NV145 to the inlet of the letdown heat exchanger is categorized as line-listing 07 (Duke Class B, ASME Class 2). Portions of this line are highlighted to be within the scope of license renewal. The staff requested that the applicant explain why a portion of the line, including isolation valve 1NV145 to the inlet of the letdown heat exchanger, is not within the scope of license renewal. The applicant indicated that the referenced piping was within the scope of license renewal, and noted that the drawing was in error.

The staff also referred the applicant to flow diagrams CN-1554-1.6 and CN-2554-1.6, which indicate that piping from the CVCS letdown line up to and including valve 1NV152 (Catawba 1) and 2NV152 (Catawba 2) are line-listing 19 (Duke Class B, ASME Class 2). The staff requested that the applicant explain why these portions of the CVCS are not within the scope of license renewal. The applicant indicated that the referenced piping was within the scope of license renewal, and noted that the drawing was in error.

The staff did not identify any omissions.

2.3.3.4.3 Conclusions

On the basis of its review of the information presented in Section 2.3.3.4 of the LRA, the supporting information in the McGuire and Catawba UFSARs, and the applicant's response to the requests for additional information, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the CVCS and its associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

*2.3.3.5 Component Cooling System*

In LRA Section 2.3.3.5, "Component Cooling System," the applicant described the components of the component cooling system that are within the scope of license renewal and subject to an AMR. This system is described in Section 9.2.4 of the McGuire UFSAR and Section 9.2.2 of the Catawba FSAR. The staff reviewed the LRA and the UFSAR for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.5.1 Technical Information in the Application

For both McGuire and Catawba, the component cooling system is a closed-loop system relied upon to maintain cooling to the essential header components as required for plant conditions, maintain an intermediate pressure boundary between the reactor coolant system and the nuclear service water (NSW) system to prevent potential radioactive release, provide containment isolation, and maintain containment closure for shutdown.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1, "Scoping Methodology," and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2, "Screening Methodology." Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively. The McGuire component cooling system is listed on page 2.2-3 of LRA Table 2.2-1. The Catawba component cooling system is listed on page 2.2-7 of LRA Table 2.2-2.

Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the McGuire and Catawba mechanical components that are subject to an AMR in Table 3.3-6, "Aging Management Results - Component Cooling System (McGuire Nuclear Station)," and Table 3.3-7, "Aging Management Results - Component Cooling System (Catawba Nuclear Station)," respectively. These tables also list the intended function of each component and the materials of construction. For both McGuire and Catawba, the applicant identified the following components from the component cooling system that are subject to an AMR—flexible hoses, heat exchanger (tubes, tube sheets, shells, channel heads, and manifold), orifices, pipe, pump casings, tank, tubing, valves bodies, and annubar tube (Catawba only). The applicant further noted in these tables that the intended functions of these components are maintaining the integrity of the component cooling system pressure boundary, transferring heat, and throttling flow.

2.3.3.5.2 Staff Evaluation

The staff reviewed Section 2.3.3.5 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the component cooling system that are within the scope of license renewal in accordance with 10 CFR 54.4, and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.5 of the LRA and the applicable piping and instrument drawings referenced therein, and the McGuire and Catawba FSARs, to determine if the applicant adequately identified the portions of the component cooling system that are within the scope of license renewal. The staff verified that those portions of the component cooling system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were so identified by the applicant in Section 2.3.3.5 of the LRA. To verify that the applicant did include the applicable portions of the component cooling system within the scope of license renewal, the staff focused its review on those portions of the component cooling system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4.

As a result of this review, the staff identified the need for additional information to complete its review. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.5-1, why two pipe segments attached to the component cooling water pumps on Catawba 1 drawing CN-1573-1.0 contain license renewal boundary changes immediately adjacent to the pumps without valving for isolation. The staff added that, for Catawba 2 drawing CN-2573-1.0, the corresponding pipe segments also were not highlighted; however, these segments did not have a license renewal flag to indicate the boundary. In its response dated April 15, 2002, the applicant noted that the non-highlighted pipe segments at the component cooling water system pumps are stuffing box overflow lines which do not serve a pressure boundary or other intended function. The applicant noted that the boundary flags on the Unit 1 drawing are correct and a similar set of boundary flags should have been shown on the corresponding Unit 2 drawing CN-2573-1.0. The staff finds the applicant's response acceptable because the lines do not serve an intended function and the licensee clarified why the Unit 2 drawings lacked boundary flags.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.5-2, why the post-accident liquid sample panel II+ cooler was outside the license renewal boundary on drawings CN-1573-1.0 and CN-2573-1.0, since failure of this piping would appear to prevent satisfactory prevention or the mitigation of an accident if accurate results cannot be obtained from the sample panel. In its response dated April 15, 2002, the applicant stated that results from the non-safety-related post-accident liquid sample panel are not relied upon to prevent or mitigate an accident. Therefore, the sample panel, and thus its cooler, does not meet the license renewal scoping criteria. Additionally, license amendments were approved for both McGuire and Catawba after the submittal of the LRA that eliminate the requirements to have and maintain the post-accident sampling systems. Based on this response, the staff agrees with the applicant and concludes that the post-accident liquid sample panel II+ cooler discussed above is not in scope because it is not relied upon to prevent or mitigate an accident.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.5-3, if a note stating that “Crossover/Overflow line connects near the top of each surge tank” on Catawba 1 drawing CN-1573-1.1 (and a corresponding note for Catawba 2 on drawing CN-2573-1.1) applied separately to what appeared to be a single crossover line and a single overflow line connecting surge tanks 1A and 1B; and if so, with the overflow line outside the license renewal boundary, the staff asked how the crossover line could fulfill its license renewal function if the overflow line is not intact. In its response dated April 15, 2002, the applicant stated that the note only applied to the line shown at J-5 to J-10. The applicant stated that this line is a horizontal connection off the side of each tank near the top of each tank, above the normal water level. The line serves as an overflow such that if one tank is overfilled, the contents will overflow into the other tank. The applicant stated that the note does not apply to the line shown at I-5 to I-10. This line is a vertical connection off the top of each tank and does not effectively connect the two tanks. The loop seals would prevent flow from one tank to the other. This line is not required for the system to perform its function, and because it taps off the top of the tank, its failure would not impact the ability of the system to perform its function. The applicant stated the same situation existed for corresponding note on the Catawba 2 diagram. The staff finds the applicant’s response acceptable, since the failure of the line shown at I-5 to I-10, and of the corresponding line on the Catawba 2 diagram, would not affect the ability of the system to perform its function. Therefore, the staff agrees that the pipe segment is outside the scope of license renewal.

The staff noted that Catawba 1 drawing CN-1573-1.2 depicts what appeared to be a (non-highlighted) blank flange at coordinates G-2. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.5-4, if the component was within the license renewal boundary. In its response dated April 15, 2002, the applicant stated that the blank flange is within the scope of license renewal. While the flange and associated piping is within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The blank flange is included with the other piping identified in Table 3.3-7 (page 3.3-78) of the LRA. Based on this clarification, the staff finds the applicant’s response acceptable.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.5-5, why the coolers for the reactor vessel supports and associated piping, which are classified as safety-related (Catawba 1 drawing CN-1573-1.3, Catawba 2 drawing CN-2573-1.3, McGuire 1 drawing MCFD-1573-03.01, and McGuire 2 drawing MCFD-2573-03.01), are considered outside the scope of license renewal. In its response dated April 15, 2002, the applicant stated that although the coolers for the reactor vessel supports and associated piping are classified as safety-related, this portion of the system is not within the scope of license renewal because the coolers are no longer used and are isolated by administratively closed valves. The exclusion of this portion of the system from the scope of license renewal represents an exception to the scoping methodology. Since a failure of the isolated piping and components could not prevent the system from performing its intended function, this portion of the system was not included within the scope of license renewal. Based on the explanation provided by the applicant, the staff finds this response acceptable.

The staff noted that Catawba 2 drawing CN-2573-1.3 appeared to have been erroneously drafted, since the highlighting to depict the reactor coolant drain tank heat exchanger as within the scope of license renewal was omitted. By letter dated January 28, 2002, the staff asked, in

RAI 2.3.3.5-6, why the Catawba 2 heat exchanger was not within scope when the corresponding Catawba 1 heat exchanger depicted in drawing CN-1573-1.3 is within scope and listed in Table 3.3-7, “Aging Management Review Results - Component Cooling System (Catawba Nuclear Station.” In its response dated April 15, 2002, the applicant confirmed that the Unit 2 reactor coolant drain tank heat exchanger is within the scope of license renewal. While the heat exchanger is within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off the heat exchanger. Based on this confirmation, the staff finds the applicant’s response acceptable.

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.5-11, the applicant to address why the vacuum breaker for the McGuire Unit 1 component cooling surge tank and the associated pipe segment were not highlighted as within the scope of license renewal (drawing MCFD-1573-01.01). The similar vacuum breaker for McGuire 2 was shown to be within scope. In its response dated April 15, 2002, the applicant confirmed that the vacuum breaker is within the scope of license renewal. While the piping and valve are within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The piping and valve associated with the vacuum breaker are listed in Table 3.3-6 (pages 3.3-53 and 3.3-55) of the LRA. Based on this confirmation, the staff finds the applicant’s response acceptable.

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.5-12, the applicant to address why McGuire 1 vent valve 1KC0884 and the associated 1-inch line were not depicted in scope of license renewal for the pressure boundary intended function on drawing MCFD-1573-02.00. In its response dated April 15, 2002, the applicant confirmed that vent valve 1KC0884 is within the scope of license renewal. While the piping and valve are within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The applicant stated that the piping and vent valve are listed in Table 3.3-6 (pages 3.3-54 and 3.3-56) of the LRA. Based on this information, the staff finds the applicant’s response acceptable.

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.5-13, that the applicant clarify the status of McGuire flow transmitters and associated instrument lines for the reactor coolant pump motor upper bearing coolers on drawings MCFD-1573-03.00 and MCFD-2573-03.00. These are noted as abandoned in place however, most (six of the eight transmitters) remain depicted as connected to the remaining instrumentation lines. The drawing notes that all instrument lines normally open to the process system, through and including the instrument, are included in license renewal scope. However, these lines generally are not flagged. In its response dated April 15, 2002, the applicant noted that, in accordance with plant modification practice, when instrumentation and associated tubing is “abandoned In place,” the tubing is cut and capped just downstream of the root valves. The abandoned instrumentation and tubing are not within the scope of license renewal because they are isolated from the process system. For other instrumentation and tubing that is not abandoned in place and remains open to the process system, the instrumentation is within the scope of license renewal, but not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i). The tubing is listed in Table 3.3-6 (page 3.3-55) in the LRA. Because the abandoned instrumentation and tubing are not relied upon to perform an intended function, the staff concludes that they are outside the scope of license renewal.

The staff did not identify any other omissions in the applicant’s scoping review.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the component cooling system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the component cooling system in Table 3.3-6 (McGuire) and Table 3.3-7 (Catawba) of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER.

The applicant identified the portions of the component cooling system that are within the scope of license renewal on drawings referenced in LRA Section 2.3.3.5. In addition, the applicant lists the mechanical components that are subject to an AMR and their intended function(s) in Table 3.3-6 (McGuire) and Table 3.3-7 (Catawba) of the LRA.

The license renewal drawings were highlighted by the applicant to identify those portions of the component cooling system that meet at least one of the scoping criteria in 10 CFR 54.4. The staff compared the LRA drawings to the system drawings and the description in the UFSAR to ensure they were representative of the component cooling system. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement on the basis of qualified life or specified time period, was excluded from an AMR.

As a result of its review, the staff determined that additional information was needed to complete its review. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.5-8, additional information regarding Note 5 on Catawba 1 drawings CN-1573-1.4 and CN-1573-1.7, and Catawba 2 drawings CN-2573-1.4, and CN-2573-1.7, which indicate that the reactor coolant pump upper motor bearing cooler connection “T” on the top of the bearing cooler should be plugged. The staff did not identify a listing for this plug on Table 3.3-7, “Aging Management Review Results - Component Cooling System Catawba Nuclear Station).” In its response dated April 15, 2002, the applicant noted that reactor coolant pump upper motor bearing cooler shell nozzles shown on the flow diagrams are labeled “J,” “K,” “T,” and “U,” and that all the nozzles and the plug are considered part of the reactor coolant pump upper motor bearing shell, which is addressed in the Table 3.3-7 (page 3.3-69) of the LRA. The staff finds the applicant’s response acceptable since the plug in question is within the scope of license renewal as part of the reactor coolant pump upper motor bearing shell.

In its RAI, the staff noted that Catawba 1 drawings CN-1573-1.4 and CN-1573-1.7, and Catawba 2 drawings CN-2573-1.4 and CN-2573-1.7, depict temperature elements (1KCTE5880, 1KCTE5920, 1KCTE5890, 1KCTE5930, etc.), which appear to be installed in thermowells in piping that is within the scope of license renewal. The thermowells for these temperature elements were not highlighted and were not included in Table 3.3-7, “Aging Management Review Results - Component Cooling System (Catawba Nuclear Station).” In LRA Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Controls,” the applicant noted that the pressure boundary function associated with resistance temperature detectors (RTDs) and thermocouples was considered during the process of identifying the mechanical pressure boundaries. Similarly for McGuire, drawing MCFD-573-02.02 indicates that temperature transmitters (1KCTX5340 and 1KCTX5380) in piping are within the scope of license renewal. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.5-9, the applicant to indicate if these instruments are located in thermowells and if wells are included in Table 3.3-7, "Aging Management Review Results - Component Cooling System." If these instruments were located in wells, the staff also asked the applicant to indicate if heat transfer was an intended function of the wells.

In its response dated April 15, 2002, the applicant clarified that, on both the McGuire and Catawba mechanical flow diagrams, the instrument nomenclature identifies whether the temperature element is installed in a thermowell. The letters "TE" in the component identification number 1KCTE5880 above indicate that a temperature element is installed in a thermowell. The letters "TX" in the component identification number 1KCTX5880 above indicate that no temperature element is installed in the thermowell. The applicant stated that the portion of the thermowell that forms a mechanical system pressure boundary is within the scope of license renewal because it serves a pressure boundary function. The applicant stated that commodity type "pipe" or "piping" is used throughout the LRA to represent the host of piping pressure boundary components that must retain their pressure boundary function. These piping pressure boundary components include not only the piping itself, but also other piping-related pressure boundary components such as elbows, tees, half-couplings, and temperature element pressure boundary parts like those discussed here. The staff found the applicant's response acceptable regarding the scoping of the thermowells for pressure boundary because they are included as part of the pipe or piping commodity group.

The applicant further stated that for thermowells, pressure boundary is the only component intended function. The applicant referred to Appendix C of NEI 95-10 (Revision 3) for an understanding of the heat transfer design aspects. The applicant stated that heat transfer is a parameter considered in the design of most safety-related structures and components, but not a primary safety function like that associated with SGs and heat exchangers. For example, while the heat capacity of the containment and interior structures is included in the modeling of the pressure and temperature transient for loss-of-coolant accidents, these secondary heat transfer functions of the safety-related structures and components need not be a specific focus of the AMR for license renewal. For thermowells, heat transfer is a secondary function and does not need to be the focus of the AMR. Therefore, pressure boundary is the only component intended function of thermowells. Based on the above, the staff found the applicant's response acceptable since there is no primary safety function associated with heat transfer for thermowells in the component cooling water system.

#### 2.3.3.5.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.5 of the LRA, the supporting information from both UFSARs and the LRA drawings, and review of the April 15, 2002, response from the applicant to the January 28, 2002, staff RAIs, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the McGuire component cooling system and the Catawba component cooling system that are within the scope of license renewal and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.3.6 Condenser Circulating Water System*

In LRA Section 2.3.3.6, "Condenser Circulating Water System," the applicant described the components of the condenser circulating water system that are within the scope of license renewal and subject to an AMR. This system is described in Section 10.4.5 of the McGuire and

Catawba UFSARs. The staff reviewed the LRA and the UFSARs for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.6.1 Technical Information in the Application

For both McGuire and Catawba, the condenser circulating water system is a non-safety-related cooling system relied upon to remove heat from the feedwater pump turbine and main condensers. The condenser circulating water system also provides a suction source of water to the turbine-driven auxiliary feedwater pump for events requiring the activation of the standby shutdown facility.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology,” and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2, “Screening Methodology.” Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively. The McGuire condenser circulating water system is listed on page 2.2-3 of Table 2.2-1 of the LRA. The Catawba condenser circulating water system is listed on page 2.2-7 of LRA Table 2.2-2.

Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the McGuire and Catawba mechanical components that are subject to an AMR in LRA Table 3.3-8, “Aging Management Results - Condenser Circulating Water System.” This table also lists the intended function of each component and the materials of construction. For both McGuire and Catawba, the applicant identified the following component types from the condenser circulating water system that are subject to an AMR—pipe, pump casings (Catawba only), valves bodies, and strainers (Catawba only). The applicant identified maintaining pressure boundary integrity as the only intended function of the SCs subject to an AMR.

2.3.3.6.2 Staff Evaluation

The staff reviewed Section 2.3.3.6 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the condenser circulating water system that are within the scope of license renewal in accordance with 10 CFR 54.4, and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.6 of the LRA and the applicable piping and instrument drawings referenced therein, and the McGuire and Catawba UFSARs, to determine if the applicant adequately identified the portions of the condenser circulating water system that are within the scope of license renewal. The staff verified that those portions of the condenser circulating water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal, and were listed by the applicant in Section 2.3.3.6 of the LRA. To verify that the applicant did include the applicable portions of the condenser circulating water system within the scope of license renewal, the staff focused its review on those portions of the condenser circulating water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4.

As a result of this review, the staff determined that additional information was needed to complete its review. Section 10.4.5.1 of the McGuire UFSAR states that the condenser circulating water system also serves as a secondary supply for the nuclear service water system. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.6-1, why the LRA does not mention the supply to the nuclear service water system as an intended function of the condenser circulating water system. The staff also requested the applicant to indicate if the discharge path from the nuclear service water system to the condenser circulating water system shown on drawing MCFD-1604-01.02 (C-7) provided an intended function. In its response dated April 15, 2002, the applicant noted that the condenser circulating water system only serves as a backup supply to the nuclear service water system and does not meet any of the scoping criteria of 10 CFR 54.4. The backup supply is not safety-related and not relied upon to prevent or to mitigate a design basis event. Additionally, the failure of this backup supply will not prevent the accomplishment of a safety-related function. Furthermore, the backup supply is not relied upon to demonstrate compliance with any of the Commission's regulations specified in 10 CFR 54.4(a)(3). The fully assured primary water source for the nuclear service water system is the flow-path from the nuclear service water system pumps, which is within the scope of license renewal. The applicant further stated that the license renewal evaluation boundaries shown on the connections for the nuclear service water system on drawing MCFD-1604-01.02 (C-7) are not intended to provide a path for the discharge of water. These boundaries provide a flow-path from the condenser circulating water system to the turbine-driven auxiliary feedwater pump for certain postulated events. The staff finds the applicant's response acceptable since neither the secondary supply nor the discharge path (if any) is safety-related, nor is either function relied upon for compliance with the regulations detailed in 10 CFR 54.4(a)(3).

Section 10.4.5.1 of the McGuire UFSAR notes that the condenser circulating water system also serves as the supply for the fire protection jockey pumps. By letter dated January 28, 2002, the staff asked, also in RAI 2.3.3.6-1, why the LRA does not mention the supply to fire protection jockey pumps as an intended function of the condenser circulating water system. The applicant stated that the supply to the jockey pumps is not considered an intended function of the condenser circulating water system and referred the staff to its response to a separate staff question (RAI 2.3.3.19-6) related to the scoping of jockey pumps in accordance with 10 CFR 54.4(a)(3). Although the staff finds the applicant’s response to RAI 2.3.3.19-6 unacceptable because of the McGuire and Catawba licensing basis for meeting the requirements of fire protection regulations, specified in 10 CFR 50.48 (discussed in Section 2.3.3.19.2 of this SER), the staff has determined that the supply of water to the jockey pumps is not required for compliance with the fire protection regulations, and the line does not serve any other intended function. Therefore, the applicant’s response to RAI 2.3.3.6-1 is acceptable.

The staff noted that for all McGuire flow diagrams referenced in the LRA for the condenser circulating water system scoping review, the license renewal boundaries are, for the most part, placed in the middle of pipe runs and not at isolable boundaries such as valves. The boundaries coincide with flags for the standby shutdown facility. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.6-4, if these boundaries related to a particular volume of water that is contained within the piping. If so, the staff requested the applicant to explain where or how the water is contained and made available to perform its intended function. In its response dated April 15, 2002, the applicant confirmed that the license renewal boundaries correspond to the standby shutdown system boundaries for the condenser circulating water system. These boundaries approximate a volume of water that is credited as the auxiliary feedwater suction source for a fire and station blackout event. The applicant stated that McGuire calculation MCC-1223.42-00-0003, “Determine Water Available for Secondary Side Makeup During a Security Event,” Revision 3, determines the available inventory required for postulated events and was reviewed during a recent NRC inspection. NRC Inspection Report 50-369/01-06, 50-370/01-06 dated February 26, 2002, indicates that this calculation was reviewed along with other design documents and no findings were identified. Additionally, the same NRC inspector who reviewed the calculation during the above inspection also participated in the McGuire and Catawba license renewal scoping and screening inspection that was performed in March 2002. The staff found the applicant's response acceptable since the system boundaries depicted are based on calculations that determine a water volume for station blackout and fire protection safe shutdown events required to be analyzed for compliance with the regulations detailed in 10 CFR 54.4(a)(3). Since these calculations have been the subject of NRC inspection, the staff has reasonable assurance that the intended function can be met with the volume of water contained in this piping.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.6-5, the applicant to clarify whether or not the 4-inch drain lines on the suction of the Catawba condenser circulating water pumps up to the discharge of the drain valves (e.g., 1RC34) are included in license renewal scope. These lines were not highlighted on drawings CN-1604-1.0 and CN-2604-1.0 The applicant response stated that the subject 4-inch drain lines are within the scope of license renewal. While the valves and associated piping are within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The piping and valves are listed in Table 3.3-8 (pages 3.3-84 and 3.3-85) of the LRA. The staff found the applicant's clarification acceptable.

By letter dated January 28, 2002, the staff questioned, in RAI 2.3.3.6-7, the placement of license renewal boundary flags on the suction and discharge flanges of the condenser circulating water pumps, which are depicted as within scope on Catawba 1 drawing CN-1604-1.0 and Catawba 2 drawing CN-2604-1.0. In its response dated April 15, 2002, the applicant confirmed that the condenser circulating water system pumps are within the scope of license renewal, and that no flags should have been placed at the inlet and discharge of the pumps. The staff found the applicant's confirmation acceptable.

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.6-8, the applicant to confirm that the license renewal boundary flag at coordinates C-4 on Catawba 1 drawing CN-1604-1.2 was erroneously single-sided. In its response dated April 15, 2002, the applicant confirmed that the license renewal flag was inadvertently shown as single-sided instead of double-sided. The continuation to CN-1592-1.0 is within the scope of license renewal. The staff found the applicant's confirmation acceptable.

Section 10.4.5.3 of the McGuire UFSAR addresses flooding of the turbine building from failure of the circulating water system. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.6-9, the applicant to indicate if the circulating water system expansion joints and the turbine building basement curbs protecting the openings to the auxiliary building were within the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the expansion joint in question is not within the scope of license renewal because it does not meet the scoping criteria. The expansion joint failure is assumed to occur and the plant is accordingly designed with mitigative features, including curbs and flood seals. The curbs are within the scope of license renewal and are addressed as "flood curbs" in Table 3.5-2 (page 3.5-10).

Flood seals along the wall of all in-scope structures are also within the scope of license renewal and are subject to an AMR. Flood seals are addressed in Table 3.5-2 (page 3.5-16). The staff found the applicant's response acceptable because the features to mitigate failure of the expansion joint are within the scope of license renewal as required by 10 CFR 54.4(a)(2).

Section 10.4.5.3 of the Catawba UFSAR addresses the maximum water level due to a simultaneous failure of the circulating water systems on both units and the subsequent draining of all water back to the respective turbine buildings. All penetrations and passageways from the turbine or service buildings to the auxiliary building are stated to be watertight below the maximum water level, which will protect safety-related equipment from failure caused by flooding. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.6-10, the applicant to indicate if the watertight features of the penetrations and passageways between these buildings and the auxiliary building have been included within the scope of license renewal in accordance with 10 CFR 54.4 paragraph (a)(2). In its response dated April 15, 2002, the applicant stated that the watertight features of the penetrations and passageways between the auxiliary and turbine/service buildings have been included within the scope of license renewal. The features include curbs, flood seals, and flood doors. Curbs are addressed in Table 3.5-2 (page 3.5-10). Flood seals are addressed in Table 3.5-2 (page 3.5-16). Flood doors are addressed in Table 3.5-2 (page 3.5-13). The staff found the applicant's response acceptable because the features relied upon to mitigate failure of the circulating water systems on both units are within the scope of license renewal as required by 10 CFR 54.4(a)(2).

The staff did not identify any other omissions in the applicant's scoping review.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the condenser circulating water system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the condenser circulating water system in LRA Table 3.3-8 using the screening methodology described in Section 2.1 of the LRA. The staff's evaluation of the scoping and screening methodology is documented in Section 2.1 of this SER.

The applicant identified the portions of the condenser circulating water system that are within the scope of license renewal by drawings referenced in LRA Section 2.3.3.6. In addition, the applicant lists the mechanical components that are subject to an AMR and their intended function (pressure boundary) in Table 3.3-8 of the LRA.

The license renewal drawings were highlighted by the applicant to identify those portions of the condenser circulating water system that meet at least one of the scoping criteria of 10 CFR 54.4. The staff compared the LRA drawings to the system drawings and the description in the FSAR to ensure they represented the condenser circulating water system. The staff performed its review by sampling the SCs that the applicant determines are within the scope of license renewal, but not subject to an AMR to verify that no structure or component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement on the basis of qualified life or specified time period, was excluded from an AMR.

As a result of this review, the staff determined that additional information was needed to complete its review. The staff noted that red highlighting was used for the expansion joints (2RC7, etc.) on the discharge of the condenser circulating water pumps for Catawba 2 on drawing CN-2604-1.0, whereas the corresponding joints were depicted as within the license renewal boundary for Catawba 1 with blue highlighting. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.6-6, if the difference in color signified some distinction for these components. The staff additionally asked why expansion joints were not listed as a component subject to an AMR in Table 3.3-8. In its response dated April 15, 2002, the applicant stated that the red highlighting of the expansion joints was an inadvertent result of the conversion of the drawing from one electronic format to another. The color change has no significance. The expansion joints were inadvertently omitted from Table 3.3-8 of the LRA. In its response, the applicant provided a supplement to Table 3.3-8, "Aging Management Review Result - Condenser Circulating Water System (Catawba only)," with the required information relating to an AMR. Since the expansion joints were included in the scope of license renewal, the staff found the applicant's response acceptable. The staff's evaluation of the AMR results for the expansion joints is documented in Section 3.3.6.2.1 of this SER.

The staff did not identify any other omissions.

2.3.3.6.3 Conclusions

The staff reviewed the information contained in Section 2.3.3.6 of the LRA, the supporting information from both UFSARs and the LRA drawings, and the applicant's responses to staff RAIs. On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the McGuire condenser circulating water system and the Catawba condenser circulating water system that are within the scope of license renewal, and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.7 Containment Ventilation Systems*

In Section 2.3.3.7 of the LRA titled, "Containment Ventilation Systems," the applicant did not identify any portions of the containment ventilation (VP) systems or mechanical components that are within the scope of license renewal and subject to an AMR. Sections 9.4.5 and 9.4.6 of the McGuire and Catawba UFSARs, respectively, state that the VP systems are not considered ESFs, and no credit has been taken for the operation of any subsystem or component in analyzing accident consequences.

2.3.3.7.1 Technical Information in the Application

The VP systems provide adequate capacity to ensure that defined temperatures are maintained in the various portions of the containment under operating and shutdown conditions in all types of weather. Sufficient redundancy is included to ensure proper operation of the systems with one active component out of service. The systems can also purge the in-core instrumentation room atmosphere so that necessary entry may be achieved.

In Section 2.3.3.7 of the LRA, and Sections 9.4.5 and 9.4.6 of the McGuire and Catawba UFSARs, respectively, the applicant stated that the VP systems are not considered ESFs. This statement is based on the applicant's review pursuant to 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2).

For McGuire and Catawba, Section 2.3.3.7 of the LRA sates—

- The VP systems provide cooling to the upper and lower compartments of containment during normal operation and shutdown.
- The VP systems provide required post-accident monitoring in accordance with the equipment qualification rule.

Based on the above, no mechanical components have any intended passive functions subject to a scoping review, therefore, no AMR is required.

2.3.3.7.2 Staff Evaluation

The staff reviewed Section 2.3.3.7 of the LRA and supporting information in the McGuire and Catawba UFSARs, Sections 9.4.5 and 9.4.6, respectively. The staff concludes that, since the VP system is not an ESF system and is not relied on to ensure that 10 CFR Part 100 limits are not exceeded, this system is not within the scope of license renewal and subject to an AMR pursuant to 10 CFR 54.4 and 10 CFR 54.21, respectively.

2.3.3.7.3 Conclusion

On the basis of its review, the staff finds that the VP systems structures and components need not be in the scope of license renewal or subject to an AMR pursuant to 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.8 Control Area Ventilation System and Chilled Water System*

The control area ventilation (VC) system is discussed in Section 2.3.3.8.1 of this SER, and the control area chilled water (YC) system is discussed in Section 2.3.3.8.2 of this SER.

2.3.3.8.1 Control Area Ventilation System

In LRA Section 2.3.3.8, "Control Area Ventilation System and Chilled Water Systems," the applicant identified portions of the VC system that are within the scope of license renewal and subject to an AMR. The applicant noted in Section 2.3.3.8 of the LRA that the VC system is further described in Sections 6.4 and 9.4.1 of the McGuire and Catawba UFSARs, respectively.

The applicant evaluated component supports for equipment, ventilation ductwork, pipe, and instrument lines in Section 2.4.3 and Table 3.5-3 of the LRA. The staff scoping evaluations of component supports and electrical components are provided in Sections 2.4 and 2.5, respectively, in this SER. Instrument line components in the VC system were evaluated in Section 2.1 of the LRA.

2.3.3.8.1.1 Technical Information in the Application

The VC system is an ESF system designed to maintain the environment in the control room, control room area, and switchgear rooms within acceptable limits for the operation of unit controls, for maintenance and testing of the controls as required, and for uninterrupted safe occupancy of the control room during a post-accident shutdown. The control room and other portions of the control area are designed to maintain proper temperatures according to site specifications. These conditions are maintained continuously during all modes of operation for the protection of control instrumentation and for the comfort of the operators.

Continuous pressurization of the control room proper is provided to prevent entry of dust, dirt, smoke, and radioactivity originating outside the pressurized zones. The control room envelope pressurization is slightly positive relative to the pressure outdoors and in surrounding areas. Outdoor air for pressurization can be taken from two locations, such that a source of less contaminated air is available regardless of wind direction. Each intake is located outside of the reactor building diametrically opposite to that unit's vent. Each outside air intake location is monitored for the presence of radioactivity, chlorine, and combustion products. If a high radiation level, chlorine concentration, or a smoke concentration is detected in the intake, station procedures direct the operator to manually close the most contaminated intake. This will ensure continuous control room positive pressure during a smoke or radiation event. Each of the outside air intakes is provided with a tornado isolation damper to prevent a depressurization of the control room and the control room area during a tornado occurrence.

The VC system consists of the following subsystems—

- control room ventilation subsystem
- control room area ventilation subsystem
- control room and control room area pressurizing subsystem
- switchgear room ventilation subsystem

The VC subsystems serving the above areas are described in detail in Section 6.4 of the McGuire UFSAR and in Section 9.4.1 of the Catawba UFSAR.

In Section 2.3.3.8 of the LRA and Sections 6.4 and 9.4.1 of the McGuire and Catawba UFSARs, respectively, the applicant identified the following VC system intended functions based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

<u>McGuire</u>

Section 2.3.3.8 of the LRA—

- to provide the normal and emergency ventilation requirements to the control room and control room area

Section 6.4 of the UFSAR—

- to maintain the proper temperatures and cleanliness in the control room, the control room area, and the switchgear rooms during plant operation, plant shutdown, post-accident conditions, and all possible weather conditions
- to maintain the proper post-accident pressurization of the control room
- to allow absolute and carbon filtration in the outside air intakes
- to align VC system air handling units with filter units upon receipt of the ESF signal
- to regulate the maximum radiation dose received by control room personnel under accident conditions within the limits of General Design Criterion (GDC) 19
- to provide VC system instrumentation for controlling and indicating temperature, radioactivity levels, and provide an early warning of smoke

Catawba

Section 2.3.3.8 of the LRA—

- to provide normal and emergency ventilation requirements to the control room and control room area

Section 9.4.1 of the UFSAR—

- to maintain the environment in the control room, control room area, and switchgear rooms within acceptable limits for the operation of unit controls, for maintenance and testing, and for uninterrupted safe occupancy of the control room during a post-accident shutdown
- to provide continuous pressurization of the control room proper and prevent entry of dust, dirt, smoke, and radioactivity originating outside the pressurized zones
- to monitor for the presence of radioactivity, chlorine, and products of combustion during all plant operational modes

On the basis of the intended functions identified above for the McGuire and Catawba VC system, the portions of this system that were identified by the applicant as within the scope of license renewal include all VC system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the portions of the VC system that are within the scope of license renewal on the flow diagrams listed in Section 2.3.3.8 of the LRA. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 3.3-11 of the LRA.

The following component types are identified as within the scope of license renewal and subject to an AMR in Table 3.3-11 of the LRA—heat exchanger - shells, tube sheets and tubes, filter trains, ductwork, orifices (McGuire only), prefilters (McGuire only), tubing, and valve bodies. The applicant noted in Table 3.3-11 of the LRA that pressure boundary, heat transfer, and filtration are the applicable intended functions of VC system components subject to an AMR.

2.3.3.8.1.2 Staff Evaluation

To verify that the applicant identified the components of the VC system that are within scope of the license renewal and subject to an AMR, pursuant to 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagrams listed in Section 2.3.3.8 of the LRA that show the evaluation boundaries for the highlighted portion of the VC system within the scope of the LRA. The staff reviewed Table 3.3-11 of the LRA, which lists mechanical components and the applicable intended functions within the scope of the license renewal and subject to an AMR. The staff also reviewed Sections 6.4 and 9.4.1 of the McGuire and Catawba UFSARs, respectively, to determine if there were any portions of the VC system that met the scoping criteria in 10 CFR 54.4(a), but were not identified as within the scope of license renewal. The staff also reviewed the respective UFSARs sections to determine if any safety-related system functions were not identified as intended functions in the LRA, and to determine if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VC system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-11 of the LRA. The staff evaluated the scoping and screening methodology, and documented its findings in Section 2.1 of this report. The staff sampled structures and components from Table 3.3-11 of the LRA to verify that the applicant identified structures and components subject to an AMR. The staff also sampled structures and components that were within the scope of license renewal but not subject to an AMR. Based on the sample, the staff verified that these structures and components perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VC system excluded from the scope of license renewal do not perform any intended functions, the staff requested additional information. The staff noted that Section 2.3.3.8 of the LRA provides a summary description of the system functions and a listing of flow diagrams. The flow diagrams highlight the evaluation boundaries, and Table 3.3-11 of the LRA tabulates the components within the scope and subject to an AMR for the VC system. The corresponding drawings and the UFSARs, however, show additional structures and components that were not listed in Table 3.3-11 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of housings for fans and air handling units from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant added that cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant's basis for excluding housings for fans and air handling units is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-2, specific information concerning the exclusion of damper housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that dampers are not included in the AMR result tables in the LRA. The applicant added that ventilation dampers, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule, because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the damper housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the control area ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.8.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-4, specific information concerning the exclusion of building sealants from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that it does not classify materials such as sealants as structures or components. The applicant stated the pressure boundary function is addressed by TS surveillance testing. However, the applicant did not indicate that any of the TS surveillance requirements listed in its response were credited for aging management (and identified as AMPs). Nor did the applicant furnish a description of, or information pertaining to, a TS surveillance AMP (including discussion of the 10 elements of the AMP) for the staff's review.

On page 2.1-24 of the LRA, the applicant stated that "seals associated with maintaining pressure boundary are limited to the divider barrier seals in the reactor building." Since the applicant does not discuss the treatment of structural sealants other than the divider barrier seal, it is not clear to the staff that building (structural) sealants were considered during an AMR of the structure (building) for which they are a subcomponent. Furthermore, according to page 3.5-10 of the LRA, the Inspection Program for Civil Engineering Structures and Components is credited by the applicant to monitor the aging of building concrete structural components (reinforced concrete beams, columns, floor slabs, and walls). According to Section B.3.21, of Appendix B of the LRA, the scope of the Inspection Program for Civil Engineering Structures and Components does not include structural sealants. Table 2.1-3, on page 2.1-15 of the SRP-LR, states that an applicant's structural AMP is expected to address structural sealants "with respect to an AMR program." The intent of this statement is that an applicant's structural AMP is expected to manage or monitor the aging effects of the structure and associated subcomponents that are identified during the AMR. The basis for this SRP guidance is documented in the summary (issued January 21, 2000,) of a December 8, 1999, meeting to discuss the staff's position on the treatment of consumables. This summary clearly states, on page 3, that structural sealants would be implicitly included at the component level and considered during the AMR. Since the structural AMP identified for the concrete structural components does not address structural sealants, and since that applicant did not identify the TS surveillances listed in its response as AMPs or provide appropriate information to support the staff's review of these surveillances as AMPs, the staff characterized this issue as SER open item 2.3-3.

In its response to this open item, dated October 28, 2002, the applicant credited a visual inspection of the structural sealant used to maintain ventilation pressure boundary integrity of the control room area, emergency core cooling pump rooms, annulus, and fuel handling building. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open item 2.3-3. The staff's evaluation of the Ventilation Area Pressure Boundary Sealants Inspection Program is provided in Section 3.0.3.19 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-5, specific information concerning the exclusion of passive components associated with ductwork from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified these passive components as subcomponents of ductwork. The applicant also stated that ventilation grills were installed only for aesthetic purposes and perform no intended license renewal function. Because the components serve only aesthetic purposes and perform no intended function, the staff concludes they are outside the scope of license renewal.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-6, specific information concerning the main control room ventilation system and specific components that had not been subjected to an AMR. In its response dated April 15, 2002, the applicant stated that ventilation dampers and cooling fans are not included in the AMR results tables in the LRA. The applicant also stated that ventilation dampers and cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding cooling fan and damper housings is not consistent with the license renewal rule because the housings are passive components that are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan and damper housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open items 2.3-1 and 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the control area ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.8.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-7(2), specific information concerning the exclusion of housings for moisture eliminators and prefilters from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified moisture eliminators and prefilters as subcomponents of the Catawba control room area pressurizing filter trains that are subject to an AMR. The staff finds the applicant's response acceptable based on the information provided.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-8(1), specific information concerning the exclusion of the control area ventilation orifice from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that the control area ventilation orifice is identified as being within scope and subject to an AMR in Table 3.3-11 of the LRA on page 3.3-112. Because the applicant had determined that the ventilation orifice is within scope and subject to an AMR, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-8(2), specific information concerning the exclusion of the McGuire air handling unit heat exchanger shells and pre-filter components from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that the McGuire air handling unit heat exchanger shells and pre-filter components were within scope, and that the highlighting was simply drawn through components instead of using LRA flags on flow diagrams. Because the applicant had determined that the air handling unit heat exchangers are within the scope and subject to an AMRs, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-3, specific information concerning the exclusion of radiation monitors, smoke detectors, air flow monitors, and chlorine monitors from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that, based on guidance provided in NEI 95-10, Revision 3, radiation monitors, smoke detectors, and chlorine detectors are not considered passive components and are therefore not subject to an AMR. Because the monitors and detectors do not perform any intended function, the staff finds the applicant's response acceptable.

Some components that are common to many systems, including the VC system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

The staff reviewed the LRA, supporting information in the UFSARs, and the applicant's responses to RAIs. In addition, the staff sampled several components from the VC system flow diagram, as identified in Section 2.3.3.8 of the LRA, to determine whether the applicant properly identified the components as within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

2.3.3.8.1.3 Conclusions

On the basis of its review, and with the resolution of open items identified in this SER section, the staff has reasonable assurance that the applicant has adequately identified the VC system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

2.3.3.8.2 Control Area Chilled Water System

In LRA Section 2.3.3.8, "Control Area Ventilation System and Chilled Water System," the applicant described the components of the control area chilled water system that are within the scope of license renewal and subject to an AMR. The control area chilled water system is described in Section 6.4 and 9.4.1 of the McGuire and Catawba UFSARs, respectively. The staff reviewed the LRA and the McGuire and Catawba UFSARs to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.8.2.1 Technical Information in the Application

For both McGuire and Catawba, the control area chilled water system is a safety-related cooling system relied upon to remove heat from the control area ventilation system.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology,” and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2, “Screening Methodology.” Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively. The McGuire control area chilled water system is listed on page 2.2-3 of LRA Table 2.2-1. The Catawba control area chilled water system is listed on page 2.2-7 of LRA Table 2.2-2.

Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the McGuire and Catawba mechanical components that are subject to an AMR in Table 3.3-9, “Aging Management Results - Control Area Chilled Water System (McGuire Nuclear Station),” and Table 3.3-10, “Aging Management Results - Control Area Chilled Water System (Catawba Nuclear Station),” respectively. These tables also list the intended functions of each component and the materials of construction. For both McGuire and Catawba, the applicant identified the following components from the control area chilled water system that are subject to an AMR—pump casings, condenser—tubes, condenser tube sheets, shells, and channel heads, economizers, evaporator—tubes, tube sheets, channel heads, and shells, oil cooler—tubes, tube sheets, channel heads, and shells, oil filters, oil separators, tanks, orifices, pipes, strainers, tubing, valves bodies, filters (Catawba only), chemical feeders (McGuire only), and flow indicators (McGuire only). The applicant further identified the intended functions of these component types to be maintaining the integrity of the control area chilled water system, transferring heat, filtration, and throttling flow.

2.3.3.8.2.2 Staff Evaluation

The staff reviewed Section 2.3.3.8 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the control area chilled water system that are within the scope of license renewal in accordance with 10 CFR 54.4, and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.8 of the LRA and the applicable piping and instrument drawings referenced therein, and the McGuire and Catawba UFSARs, to determine if the applicant adequately identified the portions of the control area chilled water system that are within the scope of license renewal. The staff verified that those portions of the control area chilled water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were so identified by the applicant in Section 2.3.3.8 of the LRA. To verify that the applicant did include the applicable portions of the control area chilled water system as within the scope of license renewal, the staff focused its review on those portions of the control area chilled water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4.

As a result of this review, the staff determined that additional information was needed to complete its review. The staff noted that vent and drain lines on control area chilled water pump P-1 up to valves 1YC0011 and 1YC0012 (McGuire drawing MCFD-1618-01.00 - L-7) were not highlighted as within license renewal scope. The license renewal highlighting was omitted from several other segments of valved vent lines on this drawing (1YC0070 and 1YC0059). By letter dated January 28, 2002, the staff asked the applicant, in RAI 2.3.3.8-2, if these segments of valved vent lines were within the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the vent and drain lines on control area chilled water system pump P-1 up to valves 1YC0011 and 1YC0012, and the vent lines associated with valves 1YC0070 and 1YC0059, are within the scope of license renewal. While the valves and associated piping are within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The piping and valves are listed in Table 3.3-9 (pages 3.3-96 and 3.3-98) of the LRA. The staff found the applicant's response acceptable.

The staff noted that two refrigerant lines for chiller C-1 (between the condenser and the economizer and between the compressor and the oil cooler) were omitted from the scope of license renewal according to McGuire drawing MCFD-1618-04.00. By letter dated January 28, 2002, the staff requested the applicant, in RAI 2.3.3.8-4, to confirm that this refrigerant line was within the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the two refrigerant lines are within the scope of license renewal. While the piping is within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off that segment of piping. The piping is listed in Table 3.3-9 (page 3.3-96) of the LRA. The staff found the applicant's response acceptable.

The staff noted that Catawba control area chilled water system LRA drawings CN-1578-2.0, 2.1, 2.2, 2.3, 2.4, and 2.5 all depict one or more thermowells installed within segments of piping that are within the scope of license renewal. However, the thermowells themselves were not highlighted, nor were there any entries for thermowells in Table 3.3-10, “Aging Management Review Results - Control Area Chilled Water System.” By letter dated January 28, 2002, the staff requested the applicant, in RAI 2.3.3.8-6, to confirm that these thermowells are within scope for license renewal and address whether the thermowells should be included for AMR of their heat transfer component function in addition to pressure boundary. In its response dated April 15, 2002, the applicant confirmed that thermowells are within the scope of license renewal as part of the piping commodity listed in LRA Tables 3.3-6 and 3.3-7. The applicant stated that pressure boundary is the only intended function of the thermowells and referred to its response to a similar RAI on thermowells.

The applicant’s response to this RAI clarified that, on both the McGuire and Catawba mechanical flow diagrams, the instrument nomenclature identifies whether the temperature element is installed in a thermowell. The letters “TE” in the component identification number 1KCTE5880 above indicate that a temperature element is installed in a thermowell. The letters “TX” in the component identification number 1KCTX5880 above indicate that no temperature element is installed in the thermowell. The applicant stated that the portion of the thermowell that forms a mechanical system pressure boundary is within the scope of license renewal because it serves a pressure boundary function. The applicant stated that commodity type “pipe” or “piping” is used throughout the LRA to represent the host of piping components that have a pressure boundary function. These piping pressure boundary components include not only the piping itself but other piping-related components, such as elbows, tees, half-couplings, and temperature elements. The staff found the applicant’s response acceptable because thermowells are included as part of the pipe or piping commodity group.

The applicant further stated that for thermowells, pressure boundary is the only component intended function. The applicant referred to Appendix C of NEI 95-10 (Revision 3) for an understanding of the heat transfer design aspects. The applicant stated that heat transfer is a parameter considered in the design of most safety-related structures and components, but not a primary safety function like that associated with steam generators and heat exchangers. For example, while the heat capacity of the containment and interior structures is included in the modeling of the pressure and temperature transient for loss-of-coolant accidents, these secondary heat transfer functions of the safety-related structures and components need not be a specific focus of the AMR for license renewal. For thermowells, heat transfer is a secondary function and does not need to be the focus of the AMR. Therefore, pressure boundary is the only component intended function of thermowells. Based on the above, the staff finds the applicant's response acceptable since there is no primary safety function associated with heat transfer for thermowells in the control area chilled water system.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.8-8, why the tubing to (apparent) back-pressure-regulating valves 1YC116 and 1YC72, shown on drawings CN-1578-2.0 and CN-1578-2.2, was not depicted as within the scope of license renewal for pressure boundary function. In its response dated April 15, 2002, the applicant stated that these valves are Fisher self-contained pressure control valves. The piping, tubing, and valves associated with these pressure-regulating valves are within the scope of license renewal and subject to an AMR. Highlighting for the small interconnecting portion from the process line to the valve controller on drawing CN-1578-2.0 was inadvertently left off. The piping, tubing, and associated valves are listed in LRA Table 3.3-10. The staff found the applicant's response acceptable.

Aside from the errors in the boundaries on the LRA drawings and other items discussed above, the staff did not identify any omissions in the applicant's scoping review.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the control area chilled water system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the control area chilled water system in Table 3.3-9 (McGuire) and Table 3.3-10 (Catawba) of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The applicant identified the portions of the control area chilled water system that are within the scope of license renewal by drawings referenced in LRA Section 2.3.3.8. In addition, the applicant lists the mechanical components that are subject to an AMR and their intended function(s) in Table 3.3-9 (McGuire) and Table 3.3-10 (Catawba) of the LRA.

The license renewal drawings were highlighted by the applicant to identify those portions of the control area chilled water system that meet at least one of the scoping criteria of 10 CFR 54.4. The staff compared the LRA drawings to the system drawings and the description in the FSAR to ensure they were representative of the control area chilled water system. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement on the basis of qualified life or specified time period. was excluded from an AMR.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.8-1, why airtrol tank fittings within the license renewal boundaries on McGuire LRA drawing MCFD-1618-01.00, and Catawba LRA drawings CN-1578-2.0 and CN-1578-2.2, did not have corresponding entries in Tables 3.3-9 and 3.3-10, "Aging Management Review Results - Control Area Chilled Water System." In its response dated April 15, 2002, the applicant stated that the airtrol tank fittings depicted on drawings MCFD-1618-01.00, CN-1578-2.0, and CN-1578-2.2 are valves used to adjust the level in the compression tanks to compensate for expansion and contraction of the fluid in the chilled water system. These valves are included in the "Valve Bodies" commodity entry in Table 3.3-9 (pages 3.3-97 and -98) and in Table 3.3-10 (pages 3.3-108 and -109) of the LRA. The staff found the applicant's response acceptable.

By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.8-3, why there are no entries for the compressor shells or cases in Tables 3.3-9 and -10, “Aging Management Review Results - Control Area Chilled Water System (McGuire Nuclear Station) and (Catawba Nuclear Station),” respectively. The compressors are depicted as within license renewal scope on LRA drawings MCFD-1618-04.00, CN-1578-2.4, and CN-1578-2.5. In its response dated April 15, 2002, the applicant noted that although the compressors are within the scope of license renewal, they are not included in the AMR results tables in the LRA. The applicant further noted that compressors, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21(a)(1)(i). The staff found the applicant's response acceptable since compressors are specifically excluded from an AMR by the regulations.

The staff noted that Catawba control area chilled water system LRA drawings CN-1578-2.0, -2.1, -2.2, and -2.3 all have a note—

> Actuator failed to the normally open position, power/control wiring disconnected and hydraulic fluid drained from actuator. Valve position maintained by actuator spring.

These notes apply to various two-way valves that would bypass flow from the fan coolers in the alternate position. By letter dated January 28, 2002, the staff stated, in RAI 2.3.3.8-7, that these valves appeared to be passive devices held in the intended position by the springs and requested that the applicant either address why these springs are not subject to an AMR (to ensure they retain the ability to maintain the position and passive nature of these valves) or provide a basis for why these components are considered active and not subject to an AMR. In its response dated April 15, 2002, the applicant stated that all valve components (actuators, operators, disks, stems, springs, etc.), except for valve bodies, are excluded from AMR in accordance with 10 CFR 54.21(a)(1)(i). The staff believed that the applicant’s response did not address the specific question regarding the active designation of these valves actuators because, with the stated configuration, there were no apparent moving parts or change in configuration or properties, and the applicant did not document plans to replace the valves on the basis of qualified life or specified time period.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440229), the applicant provided clarification that the spring, which is a piece/part of the actuator, is in a relaxed state and not compressed. In the event the valve stem attempts to reposition by some unknown force, the spring would compress slightly and then restore the valve to its initial position. Compression of the spring is a change of state. In addition, the flow through the valve itself tends to keep the valve open. In the unlikely event that the spring fails and the valve stem repositions, there is no impact on the pressure boundary function of the system components. By letter dated July 9, 2002, the applicant provided this explanation of the actuator’s design and configuration in official correspondence. The staff considers the applicant's position acceptable since it clarifies that the valves are open and flow will tend to keep the valve open, and the actuator will provide force to close the valve through the compression of the spring in the event the valves in question attempt to reposition.

2.3.3.8.2.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.8 of the LRA, the supporting information from the McGuire and Catawba UFSARs, LRA drawings, and the responses to RAIs, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the McGuire control area chilled water system and the Catawba control area chilled water system that are within the scope of license renewal and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.9 Conventional Waste Water Treatment System*

In LRA Section 2.3.3.9, “Conventional Waste Water Treatment System,” the applicant described the components of the conventional waste water treatment system that are within the scope of license renewal and subject to an AMR. The system is described in Section 9.2.8 of the McGuire UFSAR. Because of the design differences between McGuire and Catawba, the following staff evaluation applies to McGuire only.

2.3.3.9.1 Technical Information in the Application

The conventional waste water treatment system at McGuire maintains low water level in the standby shutdown facility (SSF) sump to prevent flooding of SSF equipment. The similar system at Catawba does not meet the license renewal scoping criteria.

The applicant described the process for identifying the mechanical components that are within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology.” As described in the scoping methodology, the applicant identified the portions of the conventional waste water treatment system that are within the scope of license renewal on the P&IDs that are listed in LRA Section 2.3.3.9. Consistent with the method described in LRA Section 2.1.2, “Screening Methodology,” the applicant listed the conventional waste water treatment system mechanical components that are subject to an AMR in LRA Table 3.3-12. This table also lists the component functions. Specifically, the applicant identified the following components as subject to an AMR—piping, pump casing, and valve bodies. The applicant stated that the intended component functions are to maintain pressure boundary.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9 to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the conventional waste water treatment system that are within the scope of license renewal in accordance with 10 CFR 54.4(a) and that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information provided in LRA Section 2.3.3.9, the applicable P&IDs referenced therein, and the McGuire UFSAR to determine if the applicant adequately identified the portions of the conventional waste water treatment system that are within the scope of license renewal. The staff verified that those portions of the conventional waste water treatment system that meet the scoping requirements of 10 CFR 54.4(a) were included within the scope of license renewal and were identified by the applicant in Section 2.3.3.9 of the LRA.

In LRA Section 2.3.3.9, the applicant listed applicable P&IDs for the conventional waste water treatment system. The detailed diagrams are highlighted to identify those portions of the system that are within the scope of license renewal. The staff compared the LRA diagrams to the system drawings and descriptions in the UFSAR to ensure that the diagrams were representative of the conventional waste water treatment system. To verify that the applicant included the applicable portions of the conventional waste water treatment system within the scope of license renewal, the staff focused its review on those portions of the conventional waste water treatment system that were not identified as within the scope of license renewal and verified that they did not meet the scoping criteria of 10 CFR 54.4(a). In addition, the staff reviewed the UFSAR for each facility to identify any additional system functions that were not identified in the LRA, and verified that the additional functions did not meet the scoping requirements of 10 CFR 54.4(a).

In reviewing the LRA, the staff noticed that some of the components designated as within the scope of license renewal for McGuire were not identified as within the scope of license renewal for Catawba. The staff reviewed the UFSAR in an attempt to understand the reason for these differences, but could not find an explanation. In a conference call on September 12, 2001, the staff requested that the applicant clarify the differences in design between Catawba and McGuire that resulted in these differences in scoping. The applicant explained that the SSF sump pump was included within the scope of license renewal at McGuire because credible events involving pipe breaks could cause flooding of the SSF building, which might affect the SSF equipment. Because the piping configuration at Catawba is different, the applicant did not identify any credible pipe breaks that could cause flooding of the SSF. The Catawba SSF sump pump is not required for the mitigation of flooding effects. The applicant's explanation of why the flood-mitigating function at McGuire was not warranted at Catawba clarified these scoping differences between the two plants. On the basis of the above review, the staff did not identify any omissions by the applicant in the scoping of mechanical components according to 10 CFR 54.4(a).

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the conventional waste water treatment system that were identified as within the scope of license renewal. The applicant used the screening methodology described in LRA Section 2.1.2 to identify the SCs subject to an AMR. The staff evaluation of the scoping and screening methodology is documented in Section 2.1 of this SER. In the LRA, the applicant identified the portions of the conventional waste water treatment system that are within the scope of license renewal in the P&IDs and listed the mechanical components that are subject to an AMR and their intended component functions in LRA Table 3.3-12. The staff performed its review by sampling the SCs that the applicant determined were within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions by the applicant in screening SCs according to 10 CFR 54.21(a)(1).

#### 2.3.3.9.3 Conclusions

On the basis of its review of the information contained in LRA Section 2.3.3.9, the supporting information in the P&IDs, and the McGuire UFSAR, as described above, the staff did not identify any omissions by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant adequately identified those portions of the conventional waste water treatment system that are within the scope of license renewal and the associated SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.10 Diesel Building Ventilation System*

In Section 2.3.3.10 of the LRA titled, "Diesel Building Ventilation System," the applicant identified portions of the diesel building ventilation (VD) system and the components that are within the scope of the LRA and subject to an AMR. In this section of the LRA, the applicant noted that the VD system is further described in Sections 9.4.6 and 9.4.4 of the McGuire and Catawba UFSARs, respectively.

The applicant evaluated component supports for VD system ductwork in Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the system in Section 2.1.2.3 of the LRA. The staff's scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff's evaluation of electrical components and instrumentation and controls in the VD system is documented in Section 2.5 of this SER.

2.3.3.10.1 Technical Information in the Application

The VD system is designed to provide a suitable environment for the operation of equipment and personnel access for inspection, testing, and maintenance. The VD system is designed to maintain the building temperature within both standby and operating environmental limits. Essential electrical components required for ventilation of the diesel building during accident conditions are connected to Emergency Class 1E standby power. The VD system is located completely within a Seismic Category I structure. All essential fans, dampers, ductwork, and supports are designed to withstand a safe shutdown earthquake. The diesel building ventilation air supply and exhaust openings are protected from tornado missile damage.

The McGuire and Catawba VD systems consist of the following subsystems—

<u>Normal Ventilation Subsystems</u>: The normal ventilation subsystems for each diesel-generator enclosure consist of a 100 percent capacity fan, shutoff damper, filter section, and associated ductwork. The normal ventilation subsystems have no standby capacity and operate only during normal plant operation (diesel off-cycle). The normal ventilation fans will be turned off when the associated diesel generators are started, either for test purposes or by an ESF actuation signal.

<u>Emergency Ventilation Systems</u>: The emergency ventilation subsystems (general ventilation subsystems at McGuire) for the diesel enclosures consist of two 50-percent capacity fans, ductwork, and modulating return air and outside air dampers arranged to maintain space temperature within prescribed limits when the diesel generators are operating. Excess makeup air to the diesel enclosure is relieved through automatic (pressure-operated) relief dampers.

In Section 2.3.3.10 of the LRA and Sections 9.4.6 and 9.4.4 of the McGuire and Catawba UFSARs, respectively, the applicant identified the following VD system-intended functions based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

McGuire

Section 2.3.3.10 of the LRA—

- to maintain temperature control for each diesel building when its associated diesel generator is running

Section 9.4.6 of the UFSAR—

- to filter the outside supply air and accommodate the combustion air flow requirements for each diesel engine
- to maintain the diesel building within temperature limits
- to prevent the possibility of room air short-cycling to the combustion air intakes in the event of a fan failure

Catawba

Section 2.3.3.10 of the LRA—

- to maintain temperature control for each diesel building when the associated diesel generator is running

Section 9.4.4 of the UFSA—

- to provide a suitable environment for the operation of equipment and personnel access for inspection, testing, and maintenance
- to maintain the ambient diesel building temperature within limits

On the basis of the intended functions identified above for the McGuire and Catawba VD systems, the portions of this system that were identified by the applicant as within the scope include all VD system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the portions of the VD system that are within the scope on the flow diagrams listed in Section 2.3.3.10 of the LRA. Using the scoping results methodology described in Section 2.2, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 3.3-13 of the LRA.

The following component types are identified as within the scope of license renewal and subject to an AMR and are listed in Table 3.3-13 of the LRA—ductwork, pipe, tubing, and valve bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the VD system pressure boundary.

2.3.3.10.2 Staff Evaluation

To verify that the applicant identified the components of the VD system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and

10 CFR 54.21(a)(1), the staff reviewed the flow diagrams listed in LRA Section 2.3.3.10 that show the evaluation boundaries for the highlighted portion of the VD system that are within the scope. The staff also reviewed Table 3.3-13 of the LRA, which lists the mechanical components and the applicable intended functions that are within the scope of the license renewal and subject to an AMR. The staff reviewed Sections 9.4.4 and 9.4.6 of the McGuire and Catawba USFARs, respectively, to determine if there were any portions of the VD system that met the scoping criteria in 10 CFR 54.4(a), but were not identified as within the scope. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA, and to determine if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VD system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-13 of the LRA. The staff evaluated the scoping and screening methodology, and documented its findings in Section 2.1 of this report. The staff sampled the structures and components in Table 3.3-13 of the LRA to verify that the applicant did identify the structures and components subject to an AMR. The staff also sampled the structures and components that were within the scope of license renewal but not subject to an AMR. Based on the sample, the staff verified that these structures and components perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VD system excluded from scope do not perform any intended functions, the staff requested additional information. The staff noted that Section 2.3.3.10 of the LRA provides a summary description of the system functions and a list of flow diagrams. The flow diagrams highlight the evaluation boundaries and Table 3.3-13 of the LRA tabulates the components within the scope and subject to an AMR for the VD system. The corresponding drawings and above-reviewed sections of the UFSARs, however, show additional components that were not listed in Table 3.3-13 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function, and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of housings for fans and air handling units from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant also stated cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant’s basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-2 and RAI 2.3-8(3), specific information concerning the exclusion of damper housings and valve bodies from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that dampers and/or valve bodies are not included in the AMR results tables in the LRA. The applicant also stated that ventilation dampers, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant’s basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the damper housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the diesel building ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant’s response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff’s evaluation of the AMR results is documented in Section 3.3.10.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-7(3) and RAI 2.3.3.10-1, specific information concerning the exclusion of duct heater housings (McGuire only) from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that duct heater housings should have been highlighted on flow diagrams to indicate that they are within the scope of license renewal. The applicant further stated that the duct heaters consist of electric heating elements that are mounted inside the ductwork and do not have a pressure boundary function or any other component-intended function for license renewal and are not subject to an AMR. On the basis of the information provided related to duct heater housings, the staff finds the applicant’s responses acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-8(4), specific information concerning the exclusion of pipe components (McGuire only) from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that pipe components for the diesel building ventilation systems are associated with in-scope instruments that, by convention, are not highlighted on mechanical system flow diagrams. On the basis of this clarifying information, the staff finds the applicant’s response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-5 and RAI 2.3-8(5), specific information concerning the exclusion of passive components associated with ductwork from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified these passive components as subcomponents of ductwork. The applicant also stated that ventilation grilles were installed only for aesthetic purposes and perform no intended license renewal function. On the basis of the information provided, the staff finds the applicant’s response acceptable.

Some components that are common to many systems, including the VD system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this report, the staff evaluated component supports for piping, cables, and equipment that supported the design and operation of the VD system. In LRA Section 2.5, "Scoping and Screening Results - Electrical and Instrumentation and Controls," the staff evaluated electrical and instrument components that support the operation of the VD system.

The staff reviewed the LRA, supporting information in the UFSARs, and applicant's response to RAIs. In addition, the staff sampled several components from the VD system flow diagrams identified in Section 2.3.3.10 of the LRA to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

2.3.3.10.3 Conclusions

On the basis of its review, and with the open items identified in this SER section resolved, the staff has reasonable assurance that the applicant has adequately identified the VD system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.11 Diesel Generator Air Intake and Exhaust System*

In LRA Section 2.3.3.11, "Diesel Generator Air Intake and Exhaust System," the applicant described the components of the diesel generator air intake and exhaust system that are within the scope of the license renewal and subject to an AMR. This system is described in Sections 9.5.11 and 9.5.8 of the McGuire and Catawba UFSARs, respectively. The staff reviewed the LRA and the McGuire and Catawba UFSARs to determine whether the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

The LRA refers to the "diesel generator air intake and exhaust system" for McGuire, the LRA refers to the "diesel generator air intake and exhaust system" for Catawba. For simplicity, the system will be referred to as the "diesel generator engine air intake and exhaust system" for both McGuire and Catawba.

2.3.3.11.1 Technical Information in the Application

The diesel generator air intake and exhaust system supplies air to the diesel generator engines for fuel combustion and removes exhaust from the diesel generator engines to the atmosphere outside of the building.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator air intake and exhaust system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire, and page 2.2-7 in Table 2.2-2 for Catawba. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the McGuire and Catawba mechanical components that are subject to an AMR in Table 3.3-14 of the LRA. This table also listed the intended function of each component and the materials of construction. The applicant identified the following components from the diesel generator air intake and exhaust system as subject to an AMR—silencers, filters (Catawba only), flexible connector (McGuire only), expansion joints, flexible hoses (Catawba only), pipe, tubing, and valves bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the diesel generator air intake and exhaust system pressure boundary.

2.3.3.11.2 Staff Evaluation

The staff reviewed Section 2.3.3.11 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator air intake and exhaust system that are within the scope of license renewal in accordance with 10 CFR 54.4, and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and the applicable drawings submitted by the applicant in Section 2.3.3.11 of the LRA. The staff verified that the applicant adequately identified the portions of the diesel generator air intake and exhaust system that meet the scoping requirements of 10 CFR 54.4, and that these portions were included within the scope of license renewal in Section 2.3.3.11 of the LRA. The staff focused its review on those portions of the diesel generator air intake and exhaust system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4. The staff did not identify any omissions in the applicant's scoping review.

The staff reviewed LRA Table 3.3-14, which lists the mechanical components subject to an AMR for the McGuire and Catawba diesel generator air intake and exhaust systems. The staff verified that the applicant properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator air intake and exhaust system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from LRA Table 3.3-14.

During its review of Section 2.3.3.11, the staff determined that additional information was needed to complete its review. According to the license renewal evaluation boundary highlighted on drawings MCFD-1609-05.00, MCFD-2609-05.00, CN-1609-5.0, and CN-2609-05.0, the air intake manifold, exhaust manifold, and turbochargers were determined to be within the scope of license renewal. The passive portions of these components (e.g., turbocharger housing and tubes) that have a pressure boundary function were not listed in LRA Table 3.3-14 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.11-1, that the applicant provide the basis for excluding the passive components of the diesel generator air intake manifold, exhaust manifold, and turbochargers from the lists of components subject to an AMR. In its response dated April 15, 2002, the applicant stated that, even though the diesel generators and its subcomponents, such as air intake manifold, exhaust manifold, and turbochargers, are within the scope of license renewal, diesel generators, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21(a)(1)(i). The staff found the applicant's response acceptable because, even though portions of the air intake manifold, exhaust manifold, and turbochargers are passive, these components are sub-components of the diesel generator, which is active and, therefore, not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i).

2.3.3.11.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.11 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and the RAI response, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator air intake and exhaust system that are within the scope of license renewal and those that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.12 Diesel Generator Cooling Water System*

In LRA Section 2.3.3.12, "Diesel Generator Cooling Water System," the applicant described the components of the diesel generator cooling water system that are within the scope of the license renewal and subject to an AMR. This system is described in Section 9.5.5 of the McGuire and Catawba UFSARs. The staff reviewed the LRA and the McGuire and Catawba UFSARs to determine whether the applicant adequately demonstrated that the requirements of 10 CFR Part 54 had been met.

The LRA refers to the "diesel generator cooling water system" for McGuire and to the "diesel generator engine cooling water system" for Catawba. For simplicity, the system will be referred to as the "diesel generator cooling water system" for both McGuire and Catawba.

2.3.3.12.1 Technical Information in the Application

The diesel generator cooling water system maintains the temperature of each emergency diesel generator engine and its support systems within a required operating range.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator cooling water system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and page 2.2-7 in Table 2.2-2 for Catawba. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR in Tables 3.3-15 and 3.3-16 of the LRA for McGuire and Catawba, respectively. These tables also listed the intended functions of the components and the materials of construction. For McGuire, the applicant identified the following components of the diesel generator cooling water system as subject to an AMR—annubars, surge tanks, heat exchangers (tubes, tube sheet, channel head, and shell), turbocharger intercoolers (tubes, tube sheet, channel head, and shell), pump casings, heaters, flow orifices, piping, tubing, and valve bodies. For Catawba, the applicant identified the following components from the diesel generator cooling water system as subject to an AMR—jacket water coolers (tubes, tube sheet, channel head, and shell), lube oil coolers (end covers, tubes, and shell), pump casings, standpipes, piping, tubing, and valve bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the diesel generator cooling water system pressure boundary and transferring heat.

2.3.3.12.2 Staff Evaluation

The staff reviewed Section 2.3.3.12 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator cooling water system that are within the scope of license renewal in accordance with 10 CFR 54.4 and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.12 of the LRA to verify that the applicant adequately identified the portions of the diesel generator cooling water system that meet the scoping of requirements of 10 CFR 54.4 and that these portions were included within the scope of license renewal in Section 2.3.3.12 of the LRA. The staff focused its review on those portions of the diesel generator cooling water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4. The staff did not identify any omissions.

The staff reviewed Tables 3.3-15 and 3.3-16 of the LRA, which list the mechanical components subject to an AMR for the diesel generator cooling water systems for McGuire and Catawba. The staff verified that the applicant properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator cooling water system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from Tables 3.3-15 and 3.3-16.

During its review of Section 2.3.3.12, the staff determined that additional information was needed to complete its review. According to the license renewal boundary highlighted on drawings MCFD-1609-01.00, MCFD-2609-01.00, MCFD-1609-01.01, and MCFD-2609-01.01, the turbocharger turbine cooling supply/return (e.g., heat exchanger tubes) and the flexible hose (located at coordinates K4) were identified by the applicant as within the scope of license renewal. These components were not identified as subject to an AMR and were not listed in Table 3.3-15. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.12-1, that the applicant provide the basis for not listing the turbocharger turbine cooling supply and return lines and the flexible hose in Table 3.3-15, since these components are passive and long-lived and have pressure boundary intended functions. In its response dated April 15, 2002, the applicant stated that the turbocharger turbine cooling heat exchanger tubes were included in the "piping" entry in Table 3.3-15 of the LRA. As for the flexible hose, the applicant stated that this hose is replaced during periodic maintenance. The applicant implied that the hose is replaced based on qualified life in accordance with 10 CFR 54.21(a)(1)(i) and is, therefore, not subject to an AMR. However, since this was not clearly stated in the RAI response, this issue was characterized as SER open item 2.3.3.12.2-1. In its response to this open item, dated October 28, 2002, the applicant confirmed that the flexible hose in the diesel generator cooling water system is replaced on a qualified life every 6 years and, therefore, is not subject to an AMR. The staff agrees with this conclusion, therefore, open item 2.3.3.12.2-1 is closed.

According to the license renewal boundary highlighted on Catawba drawings CN-1609-1.0 and CN 2609-1.0, the turbocharger aftercoolers and engine jackets are within the scope of license renewal. The passive portions of these components (e.g., turbocharger housing, tubes) that have a pressure boundary function were not listed on Table 3.3-14 as components subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.12-2, that the applicant provide the basis for excluding the passive components of the turbocharger aftercoolers and engine jackets from the lists of components subject to an AMR. In its response dated April 15, 2002, the applicant stated that, even though the diesel generators and their sub-components, such as the turbocharger aftercoolers and the engine jackets, are within the scope of license renewal, diesel generators, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21(a)(1)(i). The staff found the applicant's response acceptable because, even though portions of the diesel generator turbocharger aftercoolers and engine jacket are passive, these components are part of the diesel generator, which is active and not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i).

2.3.3.12.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.12 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and in the applicant's responses to RAIs and the SER open item, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator cooling water system that are within the scope of license renewal and those that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.3.13 Diesel Generator Crankcase Vacuum System*

In LRA Section 2.3.3.13, "Diesel Generator Crankcase Vacuum System," the applicant described the components of the diesel generator crankcase vacuum system that are within the scope of the license renewal and subject to an AMR. This system is further described in Section 9.5.9 of the McGuire UFSAR. This system is not described in the Catawba UFSAR. The staff reviewed the LRA and the UFSAR for McGuire to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

The LRA refers to the "diesel generator crankcase vacuum system" for McGuire, while the LRA refers to the "diesel generator engine crankcase vacuum system" for Catawba. For simplicity, the system will be referred to as the "diesel generator cooling water system" for both McGuire and Catawba.

2.3.3.13.1 Technical Information in the Application

The diesel generator crankcase vacuum system reduces the concentration of combustible gases in the crankcase. It also reduces oil leakage around inspection doors and explosion relief valves.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator crankcase vacuum system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and page 2.2-7 in Table 2.2-2 for Catawba. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR in Table 3.3-17 of the LRA for McGuire and Catawba. This table also listed the intended functions of the components and the materials of construction. The applicant identified the following components from the diesel generator crankcase vacuum system as subject to an AMR—blowers (McGuire only), oil separators (McGuire only), orifices (McGuire only), pipe, tubing (McGuire only), and valves bodies. The applicant further identified the intended function of these component types to be maintaining the integrity of the diesel generator crankcase vacuum system pressure boundary, filtration, gas removal, and throttling flow.

2.3.3.13.2 Staff Evaluation

The staff reviewed Section 2.3.3.13 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator crankcase vacuum system that are within the scope of license renewal in accordance with 10 CFR 54.4, and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.13 of the LRA and the McGuire UFSAR, to verify that the applicant adequately identified the portions of the diesel generator crankcase vacuum system that are within the scope of license renewal, and that those portions were included within the scope of license renewal in Section 2.3.3.13 of the LRA. The staff focused its review on those portions of the diesel generator crankcase vacuum system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4. The staff did not identify any omissions.

The staff reviewed Table 3.3-17 of the LRA, which lists the mechanical components subject to an AMR for the diesel generator crankcase vacuum system for McGuire and Catawba. The staff verified that the applicant properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator crankcase vacuum system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal ,but not subject to an AMR, to verify that no component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from an AMR.

During its review of Section 2.3.3.13, the staff determined that additional information was needed to complete its review. According to McGuire drawings MCFD-1609-06.00 and MCFD-2609-06.00, the two flexible hose connections on either side of the diesel generator crankcase vacuum blower are within the scope of license renewal. These flexible hose connections do not seem to be listed in LRA Table 3.3-17 as subject to an AMR. These components are within the scope of license renewal, are passive, and appear to have a pressure boundary function. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.13-1, that the applicant provide the basis for excluding these flexible hose connections from the lists of components subject to an AMR. In its response dated April 15, 2002, the applicant stated that the parts identified by the staff as "flexible hose connections" are synthetic rubber flexible expansion joints, that they are replaced during the periodic maintenance on the diesel engine, and that they are not, therefore, considered long-lived components, and are not subject to an AMR. However, since the applicant did not provide information about the replacement of these flexible connectors (whether they are replaced on condition based on specific performance parameters or based on a qualified life), the staff is unable to evaluate the acceptability of this response. This issue was characterized as SER open item 2.3.3.13.2-1. In its response to this open item, dated October 28, 2002, the applicant stated that the synthetic rubber flexible hoses on the inlet and outlet of the diesel generator crankcase vacuum blowers are inspected for cracking and signs of wear on a 6-year frequency and replaced based on condition. The staff finds this to be an acceptable basis for excluding these hoses from an AMR, therefore, open item 2.3.3.13.2-1 is closed.

Catawba drawings CN-1609-6.0 and CN-2609-6.0 identify the portions of the diesel generator crankcase vacuum system that are within the scope of license renewal. These drawings do not show a blower. It is not apparent from these Catawba drawings how the system, without a blower, performs its intended function of reducing the concentration of combustible gases in the crankcase. The Catawba UFSAR does not provide any written description of the system. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.13-2, that the licensee provide an explanation on how the system performs its intended function. In its response dated April 15, 2002, the applicant stated that no blower exists in the diesel generator crankcase vacuum system at Catawba. During normal operation, the crankcase is ventilated by natural flow to the atmosphere through a vent pipe which penetrates the diesel building roof. Since the applicant confirmed that no component (blower) is relied upon to maintain a vacuum in the diesel generator crankcase, the staff found the applicant's response acceptable.

2.3.3.13.3 Conclusion

The staff reviewed the information contained in Section 2.3.3.13 of the LRA, the supporting information from the McGuire UFSAR, applicable LRA drawings, and the applicant's responses to RAIs and the SER open item. The staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator crankcase vacuum system that are within the scope of license renewal and those that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.14 Diesel Generator Fuel Oil System*

In LRA Section 2.3.3.14, "Diesel Generator Fuel Oil System," the applicant described the components of the diesel generator fuel oil system that are within the scope of the license renewal and subject to an AMR. This system is described in Section 9.5.4 of the McGuire and Catawba UFSARs. The staff reviewed the LRA and the UFSARs for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

The LRA refers to the "diesel generator fuel oil system" for McGuire and to the "diesel generator engine fuel oil system" for Catawba. For simplicity, the system will be referred to as the "diesel generator fuel oil system" for both McGuire and Catawba.

### 2.3.3.14.1 Technical Information in the Application

The diesel generator fuel oil system is relied upon to maintain two trains of fuel oil storage and supply for the EDGs for a period of operation of no fewer than 5 days at McGuire and for 7 days at Catawba.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator fuel oil system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and page 2.2-7 in Table 2.2-2 for Catawba of the LRA. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR on Tables 3.3-18 and 3.3-19 of the LRA for McGuire and Catawba, respectively. These tables also listed the intended function of each component and the materials of construction. For McGuire, the applicant identified the following components from the diesel generator fuel oil system that are subject to an AMR—pump casings (engine-driven, booster, and transfer), tanks (day and storage), filters (duplex and transfer), flame arrestors, flow meters, orifices, pipe, strainers, tubing, and valves bodies. For Catawba, the applicant identified the following components from the diesel generator fuel oil system that are subject to an AMR—pump casings (engine-driven and motor-driven), strainer baskets (engine-driven and motor-driven), strainer bodies (engine-driven and motor-driven), filters, tanks (day and storage), flexible hoses, pipe, tubing, and valves bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the diesel generator fuel oil system pressure boundary and filtration.

### 2.3.3.14.2 Staff Evaluation

The staff reviewed Section 2.3.3.14 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator fuel oil system that are within the scope of license renewal and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.14 of the LRA and the McGuire and Catawba UFSARs to verify that the applicant adequately identified the portions of the diesel generator fuel oil system that meet the scoping requirements of 10 CFR 54.4 and that these portions were included within the scope of license renewal in Section 2.3.3.14 of the LRA. The staff focused its review on those portions of the diesel generator fuel oil system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4.

The staff reviewed Tables 3.3-18 and 3.3-19 of the LRA, which list the mechanical components subject to an AMR for the diesel generator fuel oil system for McGuire and Catawba, respectively. The staff verified that the applicant had properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator fuel oil system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from Tables 3.3-18 and 3.3-19.

During its review of Section 2.3.3.14 of the LRA, the staff determined that additional information was needed to complete its review. On McGuire drawings MCFD-1609-03.00, MCFD-1609-03.01, and MCFD-2609-03.01, the flexible hose connections on either side of the diesel generator engine are shown to be within the scope of license renewal. Although these components appear to have a pressure boundary intended function, they are not listed on Table 3.3-18 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.14-1, that the applicant provide the basis for excluding these flexible hose connections from the lists of components subject to an AMR. In its response dated April 15, 2002, the applicant stated that these flexible hose connections are replaced during periodic maintenance on the diesel engine and, in accordance with 10 CFR 54.21(a)(1)(ii), are not considered long-lived components and are not subject to an AMR. By electronic correspondence dated July 11, 2002 (ADAMS Accession No. ML023300317), the staff requested clarification of the applicant's reference to periodic maintenance to determine if the flexible hose connections are replaced on condition or replaced based on a qualified life. This issue was characterized as SER open item 2.3.3.14.2-1. In its response to this open item, dated October 28, 2002, the applicant stated that the flexible hoses in the diesel generator fuel oil system are replaced on a qualified life every 6 years and, therefore, are not subject to an AMR. Since the component is replaced on a specified interval, the staff agrees with this conclusion. Therefore, open item 2.3.3.14.2-1 is closed.

The McGuire diesel generators are equipped with features that collect leaking fuel oil and route it to the used oil storage tank. It seems that the intended function of the fuel oil leakage collection features is to ensure that leaking oil will not lead to a fire that will damage safety-related equipment, and therefore the features meet the scoping criteria of 10 CFR 54.4(a)(2) and 10 CFR 54.4(a)(3). On McGuire 1 drawings MCFD-1609-03.00 and MCFD-1609-03-01, it appears that the fuel oil collection system is not within the license renewal boundary. On McGuire 2 drawings MCFD-2609-03.00 and MCFD-2609-03.01, however, it seems that a portion of the piping of the fuel oil collection system is shown to be within the license renewal boundary. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.14-2, that the applicant provide clarification in regard to its scoping of the fuel oil leakage collection system piping and components for license renewal (e.g., diesel generator fuel oil drip tank, and diesel generator fuel oil drip tank pump) and the basis for the results of its scoping.

In its response dated April 15, 2002, the applicant stated that, although MCFD-1609-03.00 and MCFD-1609-03-01 show the license renewal boundary flag on the schematic representation of the diesel engine body, and MCFD-2609-03.00 and MCFD-2609-03.01 show the license renewal boundary flag at the connection nozzle coordinates 2-L, this highlighting inconsistency between McGuire 1 and 2 drawings does not represent a physical difference in scope. The connection point is at the diesel engine, as shown on the drawings for both units. The applicant also stated that the piping and components associated with the fuel oil leaking collection system are not within the license renewal evaluation boundary because they do not perform a function that meets the criteria of 10 CFR 54.4. The applicant specified that the components are not safety-related and do not perform any function that meets the criteria of 10 CFR 54.4(a)(1). Their failure will not prevent the accomplishment of a safety-related function and, therefore, they do not meet the criteria of 10 CFR 54.4(a)(2). And, finally, this fuel oil leakage collection feature is not credited to meet any of the Commission's regulations as specified in 10 CFR 54.4(a)(3). Fire barriers and fire suppression are provided for compliance with 10 CFR 50.48. The staff found the applicant's response acceptable because the components do not serve a support function necessary for the diesel to perform its intended function.

According to Catawba UFSAR, the fuel oil day tank retaining wall contains any leakage that may occur in the day tank or in its piping, and a high level of oil sensed inside the retaining wall initiates an alarm in the control room to alert operators of an abnormal operating condition. On Catawba drawings CN-1609-3.0, CN-1609-3.1, CN-2609-3.0, and CN-2609-3.1, the fuel oil day tank retaining walls are not highlighted as components within the scope of license renewal, even though the intended functions of the walls seem to meet the criteria of 10 CFR 54.4(a)(2). By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.14-3, that the applicant provide the basis for not including the fuel oil day tank retaining walls within the scope of license renewal. In its response dated April 15, 2002, the applicant explained that the highlighted flow diagrams show the flow boundaries of mechanical systems and that structural components are generally not represented on flow diagrams. The applicant further clarified that in cases where structural components, such as the fuel oil day tank retaining walls, are shown on the diagrams, they are not highlighted. The applicant confirmed that each fuel oil day tank retaining wall had been identified as within the scope of license renewal and was listed in Table 3.5-2 of the LRA. Therefore, the staff finds the applicant's response acceptable.

On Catawba drawing CN-2609-3.1, it appears that the piping from valve 2FD41 to valve 2FD43 is not within the scope of license renewal, even though these components are ASME Class 3 components that meet the criteria of 10 CFR 54.4(a)(2). By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.14-4, that the applicant indicate if this pipe segment is within the scope of license renewal and whether it is included in Table 3.3-19 as subject to an AMR. In its response dated April 15, 2002, the applicant confirmed that the piping from valve 2FD41 to valve 2FD43 is within the scope of license renewal and that the highlighting was inadvertently left off that pipe segment. The applicant also stated that this piping segment and valves 2FD41 and 2FD43 were included in Table 3.3-19 as subject to an AMR. The staff found the applicant's response acceptable.

#### 2.3.3.14.3 Conclusion

The staff reviewed the information contained in Section 2.3.3.14 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and in responses to RAIs and the SER open item. With the resolution of SER open item 2.3.3.14.2-1, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator fuel oil system that are within the scope of license renewal and those that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.3.15 Diesel Generator Lube Oil System*

In LRA Section 2.3.3.15, "Diesel Generator Lube Oil System," the applicant described the components of the diesel generator lube oil system that are within the scope of the license renewal and subject to an AMR. This system is described in Section 9.5.7 of the McGuire and Catawba UFSARs. The staff reviewed the LRA and the UFSARs for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

The LRA refers to the “diesel generator lube oil system” for McGuire, but to the “diesel generator engine lube oil system” for Catawba. For simplicity, the system will be referred to as the “diesel generator lube oil system” for both McGuire and Catawba.

2.3.3.15.1 Technical Information in the Application

The diesel generator lube oil system supplies lubricating oil to the diesel engine and its bearings, crankshaft, thrust faces, and other friction surfaces during both standby mode and operation mode of the diesel generators.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator lube oil system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and on page 2.2-7 in Table 2.2-2 for Catawba of the LRA. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR in Tables 3.3-20 and 3.3-21 of the LRA for McGuire and Catawba, respectively. These tables also listed the intended function of each component and the materials of construction.

For McGuire, the applicant identified the following components from the diesel generator lube oil system that are subject to an AMR—pump casings (engine-driven and before and after), coolers (tubes, tube sheet, shell, and channel head), strainers, filters, heaters, pipe, tubing, and valve bodies. For Catawba, the applicant identified the following components from the diesel generator lube oil system that are subject to an AMR—pump casings (engine driven and engine prelube), coolers (tubes, tube sheets, shell, and channel head), strainer (lube and prelube), filters (lube, prelube, and sump tank), sump tanks, flexible hoses, pipe, tubing, and valve bodies. The applicant further identified the intended functions of these component types to be filtration, transferring of heat, and maintaining the integrity of the diesel generator lube oil system pressure boundary.

2.3.3.15.2 Staff Evaluation

The staff reviewed Section 2.3.3.15 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator lube oil system that are within the scope of license renewal and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.15 of the LRA and the McGuire and Catawba UFSARs to verify that the applicant adequately identified the portions of the diesel generator lube oil system that meet the scoping requirements of 10 CFR 54.4, and that these portions were included within the scope of license renewal in Section 2.3.3.15 of the LRA. The staff focused its review on those portions of the diesel generator lube oil system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4.

The staff reviewed Tables 3.3-20 and 3.3-21 of the LRA, which list the mechanical components subject to an AMR for the diesel generator lube oil system for McGuire and Catawba, respectively. The staff verified that the applicant had properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator lube oil system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from LRA Tables 3.3-20 and 3.3-21.

During its review of Section 2.3.3.15, the staff determined that additional information was needed to complete its review. McGuire drawings MCFD-1609-02.00, MCFD-1609-02.01, MCFD-2609-02.00, and MCFD-2609-02.01, and the McGuire UFSAR do not reflect the existence of a system that collects lube oil leakage. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.15-1, that the applicant indicate which system, if any, collects lube oil leakage, and how that system is addressed in the LRA given the potential fire hazard it represents. In its response dated April 15, 2002, the applicant stated that the diesel engines at McGuire do not have a lube oil leakage collection system. The leaking lube oil drips to the floor and enters the floor drains to be routed to the sump. The staff finds the applicant's response acceptable.

Catawba drawings CN-1609-02.00, CN-1609-02.02, CN-2609-02.00, and CN-2609-02.02 do not reflect the existence of a system that collects lube oil leakage. The UFSAR for Catawba states that oil leakage from the diesel is collected in a sump in the diesel room. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.15-2, that the applicant indicate what is the intended function of this oil collection feature and how it is addressed in the LRA, given the potential fire hazard it represents. In its response dated April 15, 2002, the applicant stated that the diesel engines at Catawba do not have a lube oil leakage collection system. The leaking lube oil drops to the floor and enters the floor drains to be routed to the sump. The applicant specified that leaking lube oil would not contact any component hot enough to ignite the oil and cause a fire that would threaten the functionality of the diesel engines. The staff finds the applicant's response acceptable.

During the review of McGuire drawings MCFD-2609-02.00 and MCFD-2609-02.01, the staff noticed an inconsistency. On drawing MCFD-2609-02.00, the 1-inch system low-point drain piping and associated valve 2LD0092, and the 1-inch system drain piping and associated valve 2LD0060, are not shown to be within the scope of license renewal. On drawing MCFD-2609-02.01, the equivalent piping and valves are shown to be within the scope of license renewal. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.15-3, that the applicant verify the accuracy of the information contained in drawing MCFD-2609-02.00 and provide the basis for excluding the drain piping and associated valves from the scope of license renewal. In its response dated April 15, 2002, the applicant stated that highlighting had been inadvertently left off from that segment of piping. The applicant further stated that the piping and valves associated with that segment were listed on Table 3.3-20 of the LRA as being subject to an AMR. The staff finds the applicant's response acceptable.

On McGuire drawings MCFD-1609-02.00, MCFD-1609-02.01, MCFD-2609-02.00, and MCFD-2609-02.01, the diesel generator lube oil heater pump is shown as within the scope of license renewal. The passive portion of this component (i.e., pump housing) has a pressure boundary intended function and therefore meets the criteria of 10 CFR 54.4(a). However, it is not listed on LRA Table 3.3-20 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.15-4, the applicant to explain why the diesel generator lube oil heater pump was not subject to an AMR. In its response dated April 15, 2002, the applicant stated that the diesel generator lube oil heater pump had been inadvertently omitted from LRA Table 3.3-20 and that Table 3.3-20 was supplemented to add an entry for the diesel generator lube oil heater pump as follows—

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effects | Aging Management Programs and Activity |
|---|---|---|---|---|---|
| D/G Lube Oil Heater Pump Casings | PB | CS | Oil | None Identified | None Required |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |

The staff finds the applicant's response acceptable. The staff's evaluation of the AMR results is documented in Section 3.3.15.2.1 of this SER.

2.3.3.15.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.15 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and the RAI response from the applicant, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator lube oil system that are within the scope of license renewal and those that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.16 Diesel Generator Room Sump Pump System*

In LRA Section 2.3.3.16, "Diesel Generator Room Sump Pump System," the applicant described the components of the diesel generator room sump pump system that are within the scope of the license renewal and subject to an AMR. This system is described in Sections 9.5.10 and 9.5.9 of the McGuire and Catawba UFSARs, respectively. The staff reviewed the LRA and the UFSARs for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.16.1 Technical Information in the Application

The diesel generator room sump pump system removes leakage from equipment drains in the diesel building and protects the diesel generator from flooding due to a nuclear service water pipe rupture in the adjacent diesel room and turbine building flood.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator room sump pump system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and page 2.2-7 in Table 2.2-2 for Catawba. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR in LRA Table 3.3-22 for McGuire and Catawba. This table also listed the intended function of each component and the materials of construction. For McGuire and Catawba, the applicant identified the following component types from the diesel generator room sump pump system that are subject to an AMR—pump casings, orifices (McGuire only), pipe, and valve bodies. The applicant further identified the intended functions of these component types to be maintaining the integrity of the diesel generator room sump pump system pressure boundary, throttling flow, and transferring heat.

2.3.3.16.2 Staff Evaluation

The staff reviewed Section 2.3.3.16 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator room sump pump system that are within the scope of license renewal, and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.16 of the LRA and the McGuire and Catawba UFSARs to verify that the applicant adequately identified the portions of the diesel generator room sump pump system that meet the scoping requirements of 10 CFR 54.4, and that these portions were included within the scope of license renewal in Section 2.3.3.16 of the LRA. The staff focused its review on those portions of the diesel generator room sump pump system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4.

The staff also reviewed Table 3.3-22 of the LRA, which lists the mechanical components subject to an AMR for the diesel generator room sump pump system for McGuire and Catawba. The staff verified that the applicant had properly identified the mechanical components that were subject to an AMR from among the portions of the diesel generator room sump pump system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from LRA Table 3.3-22.

During its review of Section 2.3.3.16, the staff determined that additional information was needed to complete its review. On McGuire and Catawba drawings, the diesel generator room sump is shown not to be within the scope of license renewal. Yet, the sump is a component of the diesel generator room sump pump system, whose function is to protect the diesel generators from flooding. As a non-safety structure whose failure could prevent the diesel generator room sump pump system from remaining functional during a design basis event, the sump meets the criteria of 10 CFR 54.4(a)(2). By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.16-1, the applicant to provide the basis for not including the diesel generator room sump within the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the diesel generator room sump is within the scope of license renewal and is listed in LRA Table 3.5-2 (page 3.5-11, row 3). The applicant explained that highlighted flow diagrams show mechanical system flow boundaries and that structural components are generally not represented on flow diagrams. The applicant further clarified that, in cases where structural components, such as the diesel generator room sump, are shown on the diagrams, they are not highlighted. The staff finds the applicant's response acceptable.

2.3.3.16.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.16 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and RAI response from the applicant, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator room sump pump system that are within the scope of license renewal and those that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.17 Diesel Generator Starting Air System*

In LRA Section 2.3.3.17, "Diesel Generator Starting Air System," the applicant described the components of the diesel generator starting air system that are within the scope of the license renewal and subject to an AMR. This system is described in Sections 9.5.6 of McGuire and Catawba UFSARs. The staff reviewed the LRA and the UFSARs for McGuire and Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

The LRA refers to the "diesel generator starting air system" for McGuire and the "diesel generator engine starting air system" for Catawba. For simplicity, the system will be referred to as the "diesel generator starting air system" for both McGuire and Catawba.

2.3.3.17.1 Technical Information in the Application

The diesel generator starting air system provides fast-start capability for the emergency diesel engine by using compressed air to roll the engine until it starts, and it also supplies air to the diesel controls to operate or shut down the engine.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the diesel generator starting air system was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire and page 2.2-7 in Table 2.2-2 for Catawba of the LRA. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components that are subject to an AMR in Tables 3.3-23 and 3.3-24 of the LRA for McGuire and Catawba, respectively. These tables also listed the intended function of each component and the materials of construction. For McGuire, the applicant identified the following components from the diesel generator starting air system that are subject to an AMR—filters (control and starting air line), tank, expansion joints, pipe, tubing, and valve bodies. For Catawba, the applicant identified the following components from the diesel generator starting air system that are subject to an AMR—afterfilters, aftercoolers (tubes, tube sheet, channel head, and shells), filter (compressor inlet and distributor), tank, flow meters, moisture separators, orifices, pipe, prefilters, silencers, tubing, valve bodies, and Y-strainers. The applicant further identified the intended functions of these component types to be maintaining the integrity of the diesel generator starting air system pressure boundary and filtration.

2.3.3.17.2 Staff Evaluation

The staff reviewed Section 2.3.3.17 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the diesel generator starting air system that are within the scope of license renewal and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.17 of the LRA and the McGuire and Catawba UFSARs to verify that the applicant adequately identified the portions of the diesel generator starting air system that meet the scoping requirements of 10 CFR 54.4, and that these portions were included within the scope of license renewal in Section 2.3.3.17 of the LRA. The staff focused its review on those portions of the diesel generator starting air system that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4.

The staff reviewed Tables 3.3-23 and 3.3-24 of the LRA, which list the mechanical components subject to an AMR for the diesel generator starting air system for McGuire and Catawba, respectively. The staff verified that the applicant had properly identified the mechanical components that were subject to an AMR from among those portions of the diesel generator starting air system that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from LRA Tables 3.3-23 and 3.3-24.

During its review of Section 2.3.3.17, the staff determined that additional information was needed to complete its review. During the review of McGuire drawings MCFD-1609-04.00 and MCFD-2609-04.00, the staff noticed an inconsistency. The 1¼-inch drain piping and associated valve 2VG0040 coming off starting air tank 2B2 at coordinates B-7 are not shown to be within the scope of license renewal. The equivalent 1¼-inch drain piping and associated valves 2VG0037, 2VG0038, and 2VG0039 for starting air tanks 2A1, 2A2, and 2B1 are shown to be within the scope of license renewal. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.17-1, that the applicant verify that the highlighting on drawing MCFD-2609-04.00 was accurate. In its response dated April 15, 2002, the applicant stated that highlighting had been inadvertently left off that segment of piping. The applicant further stated that the piping and valves associated with that segment were listed in Table 3.3-23 of the LRA as being subject to an AMR. The staff finds the applicant's response acceptable.

According to the highlighting on McGuire drawings MCFD-1609-04.00 and MCFD-2609-04.00, the diesel generator filter moisture traps are not within the scope of license renewal. Yet Table 3-4 of McGuire UFSAR states that the diesel generator "filter-moisture traps" are Safety Class 3 components. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.17-2, that the applicant provide the basis for excluding these components from the scope of license renewal. In its response dated April 15, 2002, the applicant stated that the filters and associated moisture traps immediately downstream of the diesel generator starting air compressor aftercoolers on drawings MCFD-1609-04.00 and MCFD-2609-04.00, are Duke Class G components, are different from the filter-moisture traps in Table 3-4 of the McGuire UFSAR, and are not within the scope of license renewal. The applicant further explained that (1) the traps on the filter-moisture traps referred in Table 3-4 of the McGuire UFSAR are valves, (2) these valves are included in Table 3.3-23 of the LRA under "valve bodies," (3) the filter component of the filter-moisture traps referred to in Table 3-4 of the McGuire UFSAR have a pressure boundary function, and (4) these filter components were mistakenly omitted from Table 3.3-23. The applicant provided the following supplemental information to Table 3.3-23 for the starting air distributor filter—

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effects | Aging Management Programs and Activity |
|---|---|---|---|---|---|
| Starting Air Distributor Filter | PB | CS | Air (Dry) | None Identified | None Required |
| | | | Sheltered | None Identified | None Required |

Since the applicant clarified that the filter-moisture traps referred to in Table 3-4 of the McGuire UFSAR are valves, and that these valves are included in Table 3.3-23 of the LRA under valve bodies, the staff is satisfied with this aspect of its response. Since the filter was identified as within the scope of license renewal, the staff also finds this aspect of the applicant's response acceptable. The staff's evaluation of the AMR results is documented in Section 3.3.17.2 of this SER.

On Catawba drawings CN-1609-4.0, CN-1609-4.1, CN-2609-4.0, and CN-2609-4.1, the diesel generator starting air compressor body, the diesel generator starting air dryers, and the governor oil pressure boost cylinder are shown to be within the scope of license renewal. These components are passive and long-lived with a pressure boundary intended function. Therefore, they appeared to meet the criteria of 10 CFR 54.4(a) and 10 CFR 54.21. However, these components were not listed in Table 3.3-24 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.17-3, that the applicant provide the basis for excluding these components from Table 3.3-24. In its response dated April 15, 2002, the applicant stated that the diesel generator starting air compressor is within the scope of license renewal but is not subject to an AMR. The applicant explained that air compressors, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21(a)(1)(i). The staff finds the applicant's response acceptable because it is the staff's position that, even though the starting air compressor body is a passive component, the air compressor body is part of the air compressor and, as such, is not subject to an AMR, in accordance with 10 CFR 54.21(a)(1)(i).

In response to the staff's question about the diesel generator starting air dryers not being listed on Table 3.3-24 as subject to an AMR, the applicant stated that Table 3.3-24 lists the air dryer components that make up the air dryer package. The air dryer components appear in

Table 3.3-24 as filters, moisture separators, pipe, silencers, and valves. In response to the staff's question about the diesel generator governor oil pressure boost cylinder filters not being listed on Table 3.3-24 as subject to an AMR, the applicant responded that a visual inspection confirmed that there are no diesel generator governor oil pressure boost cylinder filters at Catawba. Since diagrams CN-2609-4.0 and CN-2609-4.1 erroneously show diesel generator governor oil pressure boost cylinder filters at coordinates B-7, the applicant stated that a corrective action report had been entered into the corrective action program to correct the diagrams in question. The staff also finds the applicant's response in regard to the starting air dryers and the governor oil pressure boost cylinder filter acceptable.

2.3.3.17.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.17 of the LRA, the supporting information from both UFSARs, applicable LRA drawings, and of the April 15, 2002, response from the applicant to the January 28, 2002, staff's letter, the staff concluded that there is reasonable assurance that the applicant has identified those portions of the diesel generator starting air system that are within the scope of license renewal and those that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.18 Drinking Water System*

In LRA Section 2.3.3.18, "Drinking Water System," the applicant described the components of the Catawba drinking water system that are within the scope of license renewal and subject to an AMR. This system is further described in Section 9.2.4 of the Catawba UFSAR. The LRA notes that no portion of the McGuire drinking water system is within the scope of license renewal. The staff reviewed the LRA and UFSAR for Catawba to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.18.1 Technical Information in the LRA

The Catawba drinking water system is a municipal water system consisting of a water tower, pumps, and chemical treatment equipment providing chlorinated drinking water to the plant.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1 and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2. Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively. The Catawba drinking water system is listed in LRA Table 2.2-2.

The LRA notes that the only portions of the drinking water system subject to an AMR are the Duke Class F portions of the drinking water system that are in scope at Catawba. McGuire has no Class F components in the drinking water system. Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the Catawba mechanical components that are subject to an AMR in Table 3.3-25, "Aging Management Results - Drinking Water System." This table also lists the intended function of each component and the materials of construction. The applicant identified the following components of the drinking water system that are subject to an AMR—pipes and valve bodies. The applicant identifies maintaining pressure boundary integrity as the only intended function of the SCs subject to an AMR.

2.3.3.18.2 Staff Evaluation

The staff reviewed Section 2.3.3.18 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the drinking water system that are within the scope of license renewal in accordance with 10 CFR 54.4, and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.18 of the LRA, the applicable piping and instrument drawings referenced therein, and the Catawba UFSAR to determine if the applicant adequately identified the portions of the drinking water system that are within the scope of license renewal. The Catawba drinking water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). The applicant included all components within the seismically designed piping boundaries of this system within the scope of license renewal per 10 CFR Part 54.4(a)(2). The staff verified that those portions of the drinking water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were so identified by the applicant in Section 2.3.3.18 of the LRA. To verify that the applicant did include the applicable portions of the drinking water system as within the scope of license renewal, the staff focused its review on those portions of the drinking water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4. In addition, the staff reviewed the Catawba UFSAR to identify any additional system intended functions that were not identified in the LRA, and verified that these additional intended functions did not meet the scoping requirements of 10 CFR 54.4. The staff did not identify any omissions in the applicant's scoping review.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the drinking water system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the drinking water system in Table 3.3-25 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER.

The applicant identified the portions of the drinking water system that are within the scope of license renewal by highlighted Catawba 1 and 2 drawings referenced in LRA Section 2.3.3.18. In addition, the applicant lists the pipe and valve body mechanical component commodity groups that are subject to an AMR and their intended function(s) in Table 3.3-25 of the LRA.

The piping and instrumentation drawings were highlighted by the applicant to identify those portions of the drinking water system that meet at least one of the scoping criteria of 10 CFR 54.4. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function(s) without moving parts or without a change in configuration or properties, and that are not subject to replacement on the basis of qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions.

2.3.3.18.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.18 of the LRA, the supporting information in the Catawba UFSAR, and LRA drawings, the staff did not identify any omissions in the scoping of the drinking water system by the applicant. The staff concludes that there is reasonable assurance that the applicant has identified those portions of the Catawba drinking water system that are within the scope of license renewal, and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.19 Fire Protection System*

LRA Section 2.1.1.3.1, “Fire Protection System,” identified that SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrated compliance with 10 CFR 50.48, the FP rule, are within the scope of license renewal. In LRA Section 2.3.3.19, "Fire Protection," the applicant identified the FP flow diagrams that had been marked to show the license renewal evaluation boundary for the interior and exterior FP systems for McGuire and Catawba. The applicant also identified the components of the FP system that are subject to an AMR for McGuire and Catawba in LRA Tables 3.3-26 and 3.3-27, respectively. In the letters which summarize teleconferences dated October 15, 2001 and November 2, 2001, and in a letter to the applicant dated January 28, 2002, the NRC requested additional information regarding the FP systems at Catawba and McGuire. In a letter to the NRC dated January 28, 2002, the applicant provided additional information in response to the staff’s RAIs.

In accordance with 10 CFR 54.4(a)(3), the SSCs that are relied on in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.48 are included within the scope of license renewal. The FP system is relied upon to meet the requirements of 10 CFR 50.48 at Catawba and McGuire.

2.3.3.19.1 Technical Information in the Application

In accordance with 10 CFR 50.48, the applicant is required to implement and maintain a FP program. As stated in LRA Section 2.1.1.3.1, the CLB, with regard to fire protection, differs for McGuire and Catawba. McGuire and Catawba are both licensed to 10 CFR 50.48(b) as specifically stated in SERs and the respective facility operating licenses. License Conditions 2.C.(3) and 2.C.(7) apply for the McGuire FP program and License Conditions 2.C(8) and 2.C.(6) apply for the Catawba FP program. The NRC SER, NUREG-0422, provides the staff evaluation, which documents McGuire’s compliance with Appendix A of Branch Technical Position (BTP) Auxiliary Power Conversion Systems Branch (APCSB) 9.5-1, "FP for Nuclear Power Plants." The NRC SER, NUREG-0954, provides the staff evaluation, which documents the Catawba compliance with Appendix A to BTP Chemical Engineering Branch (CMEB) 9.5-1. As part of the licensee’s response to satisfy Appendix A to BTP APCSB 9.5-1 during the original licensing, Duke committed to install a dedicated standby shutdown system (SSS) at McGuire and Catawba that would be used only in the event of a fire or plant security emergency.

In addition, LRA Section 2.1.1.3.1 stated that Catawba and McGuire both use a quality condition designation, Duke QA Condition 3, that applies uniquely to FP SSCs and services. Systems designated as QA Condition 3 are described in the LRA as those systems that promptly detect, control, and extinguish fires to limit their damage and to provide protection for SSCs and services so that a fire will not prevent the safe shutdown of the plant.

LRA Section 2.1.1.3.1 stated that the FP system at McGuire is designed to provide automatic and manual means to control and extinguish fires that may occur within building, yard, and transformer areas. The McGuire FP program is based on an evaluation of the potential fire hazards throughout the auxiliary and reactor buildings and areas adjacent to these facilities. The Catawba FP system is designed to provide automatic and manual means to control and extinguish fires that may occur within building, yard, and transformer areas. The Catawba FP program is based on an evaluation of the potential fire hazards throughout the auxiliary, diesel generator, and reactor buildings, the nuclear service water pump structure, and portions of the turbine and service buildings adjacent to these facilities.

The applicant states, in LRA Section 2.1.1.3.1, that its evaluation demonstrates that the plant will maintain the ability to perform safe-shutdown functions and minimize radioactive releases to the environment. On the basis of the methodology described above, the applicant identified that the highlighted components, shown on the FP flow diagrams listed in LRA Section 2.3.3.19, are included within the scope of license renewal.

In the LRA, Tables 2.2-1 and 2.2-2, the applicant identified that the FP system is within the scope of license renewal. In LRA Tables 3.3-26 and 3.3-27, for McGuire and Catawba, respectively, the applicant identified the mechanical components subject to an AMR, their intended functions, and the materials of construction. For McGuire, the applicant identified the following component types from the fire protection system that are subject to an AMR—cylinders (halon), fire hose rack, rupture discs, spray nozzles, sprinklers, orifices, pipe, pulsation dampeners, pump casings, standpipes, and valve bodies. For Catawba, the applicant identified the following component types from the fire protection system that are subject to an AMR—cylinders ($CO_2$), fire hose rack, spray nozzle, sprinkler, tanks ($CO_2$), orifices, pipe, pump casing and valve bodies. The applicant further identified that the intended functions of these component types to be maintaining the integrity of the fire protection system pressure boundary, filtration, and inducing spray flow.

2.3.3.19.2 Staff Evaluation

The Commission's regulations in 10 CFR 54.21(a)(1) state that for those SSCs that are within the scope of Part 54, as delineated in 10 CFR 54.4, the applicant must identify and list those SSCs that are subject to an AMR. The staff reviewed Section 2.3.3.19 of the LRA, as supplemented by conference call summaries dated October 15, 2001, and November 2, 2001, and the applicant's RAI responses dated April 15, 2002, to determine whether there was reasonable assurance that the applicant had appropriately identified the SSCs that serve FP-intended functions that are within the scope of license renewal in accordance with 10 CFR 54.4, and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

LRA Section 2.3.3.19 stated that the McGuire and Catawba UFSARs, in Section 9.5.1, "Fire Protection Systems," provide additional information concerning the interior and exterior fire protection system. The staff sampled portions of each UFSAR to identify any additional FP system function that met the scoping requirements of 10 CFR 54.4 but was not identified as an intended function in the LRA.

The staff also reviewed NUREG-0422 for McGuire and NUREG-0954 for Catawba. These NUREGs are referenced directly in the McGuire and Catawba FP license conditions, and they both summarize the FP program and commitments to 10 CFR 50.48 using the guidelines of

Appendix A to BTP APCSB 9.5-1 for McGuire and Appendix A to BTP CMEB 9.5-1 for Catawba. The staff reviewed these NUREGs to verify that the function(s) of the FP components relied upon to satisfy the provisions of Appendix A to BTP APCSB 9.5-1 and Appendix A to BTP CMEB 9.5-1 were included in the Quality Assurance (QA) Condition 3 designation and in the scope of license renewal as intended functions in the LRA.

The staff then compared the FP SSCs identified in the flow diagrams to verify that the required components were highlighted as being within the evaluation boundaries on the flow diagram, and were not excluded from the scope of license renewal. As part of the evaluation, the staff also sampled portions of the same flow diagrams for the FP system to determine if there were any additional portions of the system piping or components located outside of the evaluation boundary that should have been identified as within the scope of license renewal.

During the staff's review, a technical concern was identified regarding the appropriateness of the applicant's QA Condition 3 designation applied during the scoping evaluation to identify all FP SSCs required for compliance with 10 CFR 50.48. The QA Condition 3 designation is the primary means applied by Duke to identify FP SSCs. As noted in RAI 2.3.3.19-1, issued to Duke by letter dated January 28, 2002, UFSAR Chapter 17, "Quality Assurance Topical Report," Amendment 28, states that "QA Condition 3 covers those systems, components, items, and services which are important to fire protection as defined in the Hazards Analysis for each station. The Hazards Analysis is in response to Appendix A of NRC Branch Technical Position APCSB 9.5-1."

To ensure that all QA Condition 3 SSCs were included within the scope of license renewal, the applicant stated in conference calls, conducted on September 18 and 20, 2001, and summarized in a memorandum dated October 15, 2001, that it reviewed mechanical drawings and other QA Condition 3 program documents developed in the mid-1980s to perform their FP scoping evaluation. The QA Condition 3 designation had been identified on the mechanical drawings at the time the drawings were developed in the mid 1980s. In addition, the applicant stated in a October 3, 2001, conference call, summarized by memorandum dated November 2, 2001, that it also reviewed the UFSARs during its scoping evaluation. However, the applicant also stated that some of the SSCs referred to in the UFSARs were not identified as part of the QA Condition 3 program if they were not protecting equipment needed for safe shutdown.

By letter dated January 28, 2002, the staff stated that the exclusion of FP SSCs, on the basis that the intended function is not required for the protection of safe shutdown equipment or safety-related equipment, is not acceptable if the SSC is required for compliance with 10 CFR 50.48. Furthermore, the staff requested, in RAI 2.3.3.19-1, that the applicant provide justification for the exclusion of components that are relied upon in the staff's SERs as meeting the provisions of Appendix A to BTP APCSB 9.5-1 and Appendix A to BTP CMEB 9.5-1.

In its response dated April 15, 2002, the applicant stated, in the background section of the FP RAI responses, that the SSCs within the scope of license renewal that are required for compliance with 10 CFR 50.48 are those SSCs that protect only safety-related SSCs so that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases. The applicant also provided a detailed description to explain its view that the focus of SSCs relied on to comply with 10 CFR 50.48 (and any other FP regulations or guidance documents) is directly related to the ability to safely shut down the plant and minimize radioactive releases in the event of a fire. The applicant also provided a discussion of the Commission's regulations on license renewal and fire protection, the staff's guidance related to these regulations, and Duke's plant-specific licensing documentation and technical evaluations related to 10 CFR 50.48.

The staff did not agree that the applicant's analysis of the FP regulations had completely captured the FP SSCs required for compliance with 10 CFR 50.48. Based on the information provided from the applicant pertaining to the scoping evaluation, the staff did not have reasonable assurance that the QA Condition 3 designation included in scope all of the FP SSCs required for compliance with 10 CFR 50.48. The scope of SSCs required for compliance to GDC 3 and 10 CFR 50.48 goes beyond preserving the ability to maintain safe shutdown in the event of a fire. The McGuire and Catawba FP license conditions state that "Duke Energy shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report (FSAR), as updated, for the facility...and as approved in the applicable SERs." In addition, 10 CFR 50.48(b) states that plants whose fire protection features were accepted by the NRC as satisfying the provisions of Appendix A to BTP APCSB 9.5-1 or were accepted in comprehensive SERs prior to publication of Appendix A to BTP APCSB 9.5-1 in August 1976, were only required to meet the provisions of Sections III.G, III.J, and III.O of Appendix R. Commitments to meet Appendix A to BTP APCSB 9.5-1 or Appendix A to BTP CMEB 9.5-1, as documented in SERs which are directly referenced in the fire protection license condition, are not considered to merely mention a system, structure, or component since the commitments support a specified regulatory function. Therefore, all FP SSCs required for compliance with 10 CFR 50.48, including GDC 3, are required to be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(3).

In the following paragraphs, the staff describes the components that appear to perform FP intended functions because they are identified and discussed as commitments in SERs or in the UFSAR, both of which are referenced in the license conditions for McGuire and Catawba. Based on the staff's review, these components appear to be required for compliance with 10 CFR 50.48, but were not designated by the applicant as QA Condition 3 SSCs on the basis that they were not protecting safe shutdown equipment or safety-related equipment.

<u>Fire Hydrants</u>. By letter dated January 28, 2002, the staff questioned, in RAI 2.3.3.19-4, the applicant's methodology, which excluded fire hydrants that can be isolated from the flowpath from the scope of license renewal. In its response dated April 15, 2002, the applicant stated that, with the exception of two hydrants at Catawba that protect the nuclear service water pump structure, hydrants in the yard are not relied upon to protect safety-related SSCs required for safe shutdown. These two credited hydrants are included in scope, along with some hydrants that are located along the flowpath and cannot be isolated. The hydrants that cannot be isolated from the flowpath are included within license renewal scope. The applicant stated that the other hydrants are not in scope because they are not relied upon for fire suppression of safety-related SSCs to ensure safe shutdown and are isolable from the flowpath (via upstream isolation valves). The applicant explained in its RAI response that these isolable, downstream hydrants and piping are beyond the requirements of 10 CFR 50.48 and are not within the scope of license renewal. The staff found no basis for the argument that the isolable, downstream hydrants and piping are beyond the requirements of 10 CFR 50.48. GDC 3 provides for the protection of SSCs where a fire might also significantly increase the risk of radioactive releases which may not be associated with safe shutdown. Hydrants would provide for protection against fires in areas where radioactive releases could be released to the environment.

McGuire is required to meet Appendix A to BTP 9.5-1, and Catawba is required to meet the position documented in CMEB 9.5-1. Both documents state that “outside manual hose installation should be sufficient to reach any location with an effective hose stream. To accomplish this, hydrants should be installed approximately every 250 feet on the yard main system.” Furthermore, the staff asked, in RAI 2.3.3.19-4, the applicant to verify that hydrants located on the yard main system were not excluded from the scope of license renewal. In its response dated April 15, 2002, the applicant did not verify or address this item. The staff is concerned that lack of maintenance of fire hydrants over time can result in partially closed or shut valves and clogging of hydrants with debris, which will affect the system flow results. Furthermore, fire hydrants are considered passive and long-lived components in accordance with 10 CFR 54.21. Therefore, this issue was characterized as SER open item 2.3.3.19-1.

The staff and the applicant met on October 1, 2002, to discuss SER open items pertaining to the scoping and screening of fire protection equipment. A summary of this meeting was issued on November 26, 2002 (ADAMS Accession No. ML023330429). During this meeting, Duke stated that the fire protection plant designs for McGuire and Catawba are unique. By design, most plants rely upon the hydrants for compliance with 10 CFR 50.48 as a backup means of suppression to ensure defense-in-depth. However, the fire protection system in the auxiliary buildings for McGuire and Catawba consists of two headers that feed the automatic and manual suppression systems. These headers provide sectional isolation capability between the automatic and manual suppression systems such that a single failure cannot cause loss of water supply to both the automatic and manual means of suppression in a given area. As such, defense-in-depth exists in the fire protection system design in the auxiliary building for McGuire and Catawba. In addition, Duke stated that no potential sources of radioactive releases are protected in the event of a fire by those hydrants that are excluded from the scope of license renewal at McGuire or Catawba. The staff acknowledged during this meeting that, since the applicant does not rely on the hydrants as a backup means of suppression or to protect against the release of radioactive releases for compliance to 10 CFR 50.48, this issue was confirmatory pending the staff’s receipt of this explanation of the McGuire and Catawba design in a formal SER open-item response from Duke. The applicant provided this response to the staff in a letter dated October 28, 2002. The applicant’s written response accurately reflects the information provided during the October 2, 2002, meeting. Therefore, SER open item 2.3.3.19-1 is closed.

<u>Jockey Pump Casings</u>. Flow diagrams MCFD-1599-01.00 and CN-1599-1.0 do not include the jockey pump casings within the scope of license renewal. The jockey pump’s importance is to prevent the main fire pumps from cycling off and on with system pressure changes. This protects the main fire pumps, which are also required for compliance with 10 CFR 50.48, from excessive use which could prevent the fire pumps from being reliable when needed to provide water during a fire event. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.19-6, the applicant to (1) provide justification for excluding the jockey pumps, and (2) justify the appropriateness of the methodology used to identify FP systems and components that are within the scope of license renewal based solely upon their QA Condition 3 designation (or lack thereof). The staff also presented the regulatory basis, consistent with previous license renewal SERs, explaining how the jockey pumps were required to meet 10 CFR 50.48, in its RAI.

In its response dated April 15, 2002, the applicant stated that the jockey pump provided more of a support function and not an intended function, in that it refills the suppression system during standby mode when the system has lost water due to normal system leakage. The applicant also stated that the jockey pumps do not protect safety-related SSCs (so that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases) and that the jockey pump was therefore beyond the requirements of 10 CFR 50.48. The staff disagrees on the basis that the applicant did not address the fact that this component was accepted by the NRC staff in an SER as satisfying the provisions of Appendix A to BTP 9.5-1 for McGuire and Appendix A to CMEB 9.5-1 for Catawba, in accordance with 10 CFR 50.48(b). Furthermore, in its response to Appendix A to BTP 9.5-1 (McGuire, October 7, 1982) and Appendix A to CMEB 9.5-1 (Catawba, November 4, 1983), Duke described its approach to meeting each of the requirements in the BTPs and stated, for both McGuire and Catawba, that the jockey pumps are provided to maintain pressure in the system. The staff found this response from the applicant unacceptable and characterized this issue as SER open item 2.3.3.19-2.

During the staff's October 1, 2002, meeting with Duke, and as stated in a letter from the applicant dated October 28, 2002, Duke agreed that the jockey pumps are part of the current licensing basis of McGuire and Catawba in that they exist as a commitment to satisfy the provision of Appendix A to BTP 9.5-1 for McGuire and Appendix A to CMEB 9.5-1 for Catawba. However, Duke felt that the jockey pumps did not meet the criterion of 10 CFR 54.4(a)(3) on the basis that they are not relied on in a safety analysis or plant evaluation to perform a function to demonstrate compliance with 10 CFR 50.48. In the applicant's opinion, a function is not required to demonstrate compliance with 10 CFR 50.48 unless that function is to maintain the ability to safely shut down the plant and minimize radiation releases in the event of a design basis fire. The staff disagrees with Duke's position because, as the staff has consistently shown, the jockey pumps for McGuire and Catawba are credited in their respective FSARs and SERs (and other design basis documents) for maintaining pressure on the fire water header, which is a function that is clearly required for compliance with 10 CFR 50.48. Additionally, the FSARs and SERs are referenced in the fire protection plan license conditions for each plant.

In its October 28, 2002, letter, Duke identified the jockey pump casings, piping, and other components of the fire water pressure maintenance sub system as within the scope of license renewal. The applicant also provided the AMR results for the pressure maintenance subsystem of the fire protection system containing the jockey pump. Therefore, the staff is satisfied with the resolution of this issue. Open item 2.3.3.19-2 is closed. The staff's evaluation of the AMR results for the fire water pressure maintenance sub system is documented in Section 3.3.19.2 of this SER.

<u>Suppression for Charcoal or Carbon Filters</u>. Section 9.5.1.2.1 of the Catawba UFSAR states that the interior fire water (RF) system provides a fixed water suppression system for charcoal filters. The RF system provides water for interior fire protection from multiple connections to the yard loop. Fire protection piping to charcoal filter units is not highlighted on flow diagrams CN-1599-2.1(at J-7 and J-10) and CN-1599-2.2 (at H-2 and H-4). In the October 3, 2001, conference call, the applicant stated that the charcoal filters are associated with a non-safety-related containment ventilation system equipment that cools the containment building to make it habitable for maintenance, operations, and radiation protection of personnel during refueling outages. The staff is concerned that charcoal filters are typically inaccessible by personnel so that in the event of a fire, the water spray system is the only credited means to suppress this type of fire. By letter dated January 28, 2002, the staff requested the applicant, in RAI 2.3.3.19-9, to justify why RF piping to the charcoal filter units is not in scope. In its response dated April 15, 2002, the applicant stated that the subject filters are not charcoal filters but high-purity carbon filters, and that the carbon used in these filter beds has an ignition temperature of

approximately 330 °C. Since the air temperature in the process flowpath of this filter is not designed to reach temperatures this high, the applicant stated that the carbon filters are not combustible in the environment for which they are designed to operate. The applicant concluded that the need for a fixed water suppression system has been precluded by the use of the bed filter with an essentially noncombustible material.

The staff did not agree with this justification for excluding the fixed water suppression system from the scope of license renewal. The staff believes that the applicant's distinction between charcoal filters and carbon filters is not material because, irrespective of the term, the filter medium of carbon (charcoal) is combustible. Therefore, the need for suppression capability has not been precluded by this use of alternative terminology, and exclusion of these components from the scope of license renewal is not justified.

The staff also noted that Duke is committed to providing fire suppression features for carbon filters (purity is not a criterion). By letter from Hal B. Tucker (Duke) to Harold Denton (NRC), dated November 4, 1983, Duke submitted a revised response to BTP APCSB(CMEB) 9.5-1. In this response, Duke identified the containment auxiliary carbon filters and states, on pages 48-50, "Containment Auxiliary Carbon Filter," that carbon filters are protected with a built-in water spray system. This statement is directly related to the regulatory requirement of Appendix A to BTP CMEB 9.5-1 that "fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52." This issue was characterized as SER open item 2.3.3.19-3.

In a letter dated October 28, 2002, the applicant stated that it had performed further review and determined that the piping, sprinklers, and valve bodies associated with the Catawba reactor building charcoal filter unit sprinklers should have been identified as within the scope of license renewal and subject to aging management review. The components of this portion of the Catawba FP system are listed in Table 3.3-27 of the LRA. Since the fixedwater suppression system for the charcoal filters was included in scope and subject to an AMR, the staff is satisfied with its resolution. Open item 2.3.3.19-3 is closed. The staff's evaluation of the AMR results is documented in Section 3.3.19.2 of this SER.

<u>Suppression Systems and Hose Stations</u>. Sections 9.5.1.2.1 and 9.5.1.2.2 of the McGuire and Catawba UFSARs identify and describe water suppression systems and hose stations that protect various yard structures and selected areas in the McGuire and Catawba turbine buildings. However, the staff noted that these water suppression systems and hose stations were excluded from the scope of license renewal. By letter dated January 18, 2002, the staff asked, in RAIs 2.3.3.19-1, 2.3.3.19-3, and 2.3.3.19-8, why these fire protection features for the components listed in Sections 9.5.1.2.1 and 9.5.1.2.2 of the UFSAR (e.g., hydrants that are connected to the yard main, oil storage house, oxygen and acetylene gas storage yard area, compressed flammable gas cylinder storage area, main turbine piping and bearings, unit startup and standby oil-filled power transformers, main turbine lube oil reservoirs, hydrogen seal oil unit, and the feedwater pump turbines) were excluded from the scope of license renewal.

In its response dated April 15, 2002, the applicant stated that their UFSAR contained a general description of all of the FP features in each plant, and not just those FP SSCs required for 10 CFR 50.48. This is contrary to the applicant's license conditions for McGuire and Catawba, which show that the FP CLB is defined in part by the UFSAR. Furthermore, 10 CFR 54.2 defines the UFSAR as a means to document the CLB at each facility. Therefore, the staff does not agree that the components listed in the UFSAR as satisfying the FP program can be excluded from the scope of license renewal. From a technical standpoint, water suppression systems and deluge systems are important to provide automatic suppression in areas where the fire is expected to either be controlled until the fire brigade arrives or where due to the hazard, the suppression system is provided to extinguish the fire. Manual hose stations are important because they allow the fire brigade to deliver water to quickly extinguish fires in the areas closest to the hose station. Age-related degradation of these components could lead to the inability to control or extinguish a fire, which would allow it to grow uncontrolled. Therefore, this issue was characterized as SER open item 2.3.3.19-4 for unresolved RAIs 2.3.3.19-1, 2.3.3.19-3, and 2.3.3.19-8. The suppression systems of concern fall into two categories— (1) fire suppression in outlying areas, and (2) fire suppression in the McGuire and Catawba turbine buildings. Therefore, these categories are addressed separately in the following two sections of this SER.

<u>Fire Suppression in Outlying Areas</u>. The staff's concern with the suppression systems in the outlying plant areas was that these systems may be credited to mitigate an exposure hazard to surrounding buildings in the event of a fire. This item was discussed during the staff's October 1, 2002, meeting with Duke, and the applicant agreed to further research the licensing basis documents pertaining to these exposure hazards and to notify the staff of its findings. The staff agreed to perform a more detailed review as well. Subsequently, in its October 28, 2002, response to this open item, the applicant stated that it had reviewed submittals made to the NRC during original licensing. Duke concluded that separation was the only credited fire protection feature for those areas listed in the open item that are located in the yard. After reviewing the McGuire and Catawba licensing basis documentation, the staff agreed with the applicant's finding that the suppression systems in the outlying plant areas did not appear to be credited due to physical separation from surrounding buildings.

<u>Fire Suppression in the Turbine Buildings</u>. In its letter dated October 28, 2002, the applicant stated that, for the turbine buildings at McGuire and Catawba, the main turbine lubricating oil tank, which contains the largest volume of combustible fluid in the turbine building, is located approximately 100 feet from the fire barrier that separates the auxiliary building from the service building and turbine building. Based on the applicant's review, these areas did not present an exposure hazard to the auxiliary building.

However, the staff had also performed a more detailed review of the licensing basis for fire suppression in all areas of the plant, including the turbine buildings, and concluded that the NRC reviewers had relied on manual suppression (manual hose stations) to provide programmatic defense in depth in accordance with 10 CFR 50.48 during original licensing.

The staff reviewed the Statement of Considerations (SOC) for the proposed fire protection rule, 10 CFR 50.48, to understand the Commission's view of the defense-in-depth concept for fire protection. The SOC, published in the May 29, 1980, edition of the *Federal Register* (45 FR 36082), states—

> The concept of defense in depth is here extended to fire protection (1) to prevent fires from starting, (2) to rapidly detect, control, and promptly extinguish those fires that do occur, and (3) to arrange the structures, systems and components important to safety so that a fire that starts in spite of the fire prevention activities and that is not promptly extinguished by the fixed automatic or manual fire suppression activities will not prevent the safe shutdown of the plant. (45 FR @ 36084)

The SOC also addresses Section C, “Manual Fire Fighting”, of the proposed rule, stating—

> This section requires that manual fire fighting capability (a fire brigade) be provided in all areas containing or presenting a fire hazard to structures, systems, or components important to safety. (45 FR @ 36084)

The staff noted that a fire brigade would rely upon manual hose stations to combat a fire. The November 19, 1980, edition of the *Federal Register* (45 FR 76602), also addresses Section C, “Manual Fire Fighting”, of the final rule, stating—

> Considerable reliance is placed on automatic fire suppression systems throughout a nuclear power plant. However, manual fire fighting activities often can control and extinguish slowly developing fires before an automatic fire suppression system is actuated. In addition, fires that are controlled or extinguished by automatic systems require a certain amount of manual response. Also, some areas of the plant do not warrant installation of automatic fire suppression systems. Manual response is the only fire suppression available for these areas; thus, <u>it is important that manual fire fighting capability be present in all areas of the plant, and that standpipe and hose stations be located throughout the plant</u>. The standpipe and hose stations are to be located so that at least one effective hose stream can be brought to bear at any location in the plant containing or presenting a hazard to structures, systems, or components <u>important to safety</u>. (45 FR @ 76605)

The fire protection regulations and guidance documents (Appendix R and Appendix A to BTP 9.5.1) define the concept of defense-in-depth for fire protection programs consistent with definition provided in the SOC. The guidance in Appendix A to BTP 9.5-1 and CMEB 9.5-1, which was implemented by Duke during original licensing, states in part that “interior manual hose stations should be provided in all buildings, including containment, on all floors.” This ensures that interior manual hose installation should be able to reach any location with at least one effective hose stream. Page 64 of the letter dated October 7, 1982, for McGuire, indicates that Duke implemented this guidance. Furthermore, Duke’s docketed response does not state that manual hose stations were not provided in the turbine building due to the presence of a 3-hour-rated fire barrier. Similarly, page 76 of the letter dated November 4, 1983, for Catawba, indicates that manual hose stations were installed per the guidance of CMEB 9.5-1. As with the response for McGuire, Duke’s response in this letter pertaining to Catawba does not state that manual hose stations were not installed in the turbine building due to the presence of a 3-hour-rated fire barrier.

The staff reviewed Duke’s fire protection reviews for both plants, which were documented in design basis specifications obtained during the NRC inspection for scoping and screening. McGuire’s “Plant Design Basis Specification for Fire Protection”, MCS-1465.00-00-0008, Revision 4, and Catawba’s Plant Design Basis Specification for Fire Protection, Spec. CNS-1465.00-00-0006, Revision 4, document the fire protection reviews for McGuire and Catawba, respectively. These documents also indicated that, in its response to Appendix A to BTP 9.5-1 and CMEB 9.5-1, Duke did not take any exception to the statement that “interior manual hose stations should be provided in all buildings, including containment, on all floors.”

For these reasons, the staff disagreed with the applicant’s finding that hose stations were not required for compliance with 10 CFR 50.48. Duke had placed total reliance on the 3-hour fire barrier and did not identify the manual hose stations, which would be utilized as part of defense-in-depth to suppress a turbine building fire, as within the scope of license renewal. Therefore, although the staff agreed with Duke’s finding that the suppression systems in the outlying plant areas did not appear to be credited due to physical separation from surrounding buildings, open item 2.3.3.19-4 remained unresolved.

In a letter to Duke dated November 13, 2002, the staff notified the applicant that its response to SER open item 2.3.3.19-4 was inadequate to resolve the item. The staff also requested complete and sufficient information to complete its review of this issue. In its response, dated November 18, 2002, Duke stated that the main lubricating oil tank is the worst combustible load in the turbine building and that it does not present an unacceptable fire exposure hazard. The staff disagreed with this statement and believes that the main turbine lubricating oil tank does present an unacceptable fire exposure hazard because a lube oil fire typically produces high heat release rates that can challenge the integrity of a 3-hour-rated fire barrier. In the event that a lube oil fire starts, without manual suppression capability to control or limit the spread of fire, this type of fire could propagate through the walls or roof of the turbine building to other fire areas in less than 3 hours. The rated fire wall is only a passive structure (one aspect of defense-in-depth) installed to prevent a turbine lube oil fire from damaging equipment important to safety in adjacent fire areas (e.g., the auxiliary building). In addition, the fire barrier would not protect SSCs important to safety in the turbine building in accordance with GDC 3, which requires fire protection for SSCs that are important to safety.

In the November 18, 2002, letter, Duke contended that the guidance in Appendix A to BTP 9.5-1 was later clarified in the CMEB 9.5-1 with respect to manual hose station installation to only require manual hose stations for protection of safety-related SSCs. Appendix A to BTP 9.5-1 states in part that “Manual hose stations should be able to reach any location with at least one effective hose stream.” CMEB 9.5-1, which was issued later, states that “Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety-related area in the plant.” Both versions state that “To accomplish this, standpipes with hose connections should be provided in all buildings on all floors.” No exceptions to either version were taken by Duke to exclude the turbine building. The guidance, when considered within the context of GDC 3 and 10 CFR 50.48, provides for the protection of all SSCs important to safety and not just for safety-related or safe shutdown equipment.

In its November 18, 2002, response to the staff’s November 13, 2002, letter, the applicant stated that the regulations use the terms “safety-related” and “important-to-safety” interchangeably and that the turbine buildings did not contain equipment important to safety. The staff has referred to Generic Letter (GL) 84-01, “NRC Use of the Terms, ‘Important to Safety’ and ‘Safety Related,’” for a discussion of the scope and meaning of SSCs important to safety. The staff also noted that all safety-related equipment is inherently important to safety, although the classification of equipment that is important to safety extends beyond that which is safety-related.

The staff also determined that, contrary to the applicant’s statement, the McGuire and Catawba turbine buildings do in fact house equipment important to safety, including 6900/4160 volt transformers (for normal electrical power), sensing instrumentation and circuitry associated with main turbine operational inputs to the reactor protection system, sensing instruments and control circuitry for mitigating anticipated transient without scram (ATWS) events, and, for Catawba in particular, a backup suction source for auxiliary feedwater during certain design basis events involving the standby shutdown system.

In accordance with 10 CFR 54.4(a)(3), SSCs that are relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with 10 CFR 50.48 are required to be in scope of license renewal. Therefore, it is the staff's position that Duke's licensing basis documentation, reviewed within the context of 10 CFR 50.48 and GDC 3, shows that the manual hose stations in the turbine building are relied upon for compliance with 10 CFR 50.48.

In its November 18, 2002, response to the staff's November 13, 2002, letter, the applicant stated that, although it disagreed with the staff's position with respect to manual hose stations in the turbine buildings, the equipment associated with these fire suppression features would be included in the scope of license renewal. The applicant also provided AMR results tables for the passive equipment brought into the scope of license renewal. Therefore, open item 2.3.3.19-4 is resolved. The staff's evaluation of the AMR results is documented in Section 3.3.19.2 of this SER.

<u>Suppression for Reactor Building Purge Exhaust Filters</u>. Section 9.5.1.2.3, "Fire Protection, Category I Safety Related," of the McGuire UFSAR states that the manually operated water spray systems provide fixed spray patterns of water for reactor building purge exhaust filters 1A, 1B, 2A, and 2B, which appear to be Category 1, safety-related components. However, drawing MCFD 1599-02.01, coordinates H-3, G-3, C-5, and B-7, indicates that piping and sprinklers associated with this function are excluded from the scope of license renewal. The fire protection rule, 10 CFR 50.48, states that each operating nuclear power plant must have a fire protection plan. A license condition for Catawba states that Duke Energy Corporation shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSARs for the respective facilities. Since the UFSAR states that the manually operated water spray systems provide fixed spray patterns of water for reactor building purge exhaust filters 1A, 1B, 2A, and 2B, the staff was concerned that the manually operated water spray systems for these filters were inappropriately excluded from the scope of license renewal and an AMR. This issue was characterized as SER open item 2.3.3.19-6.

In a letter dated October 28, 2002, Duke stated that the flexible hoses, piping, sprinklers, and valve bodies associated with the McGuire reactor building exhaust filters spray system should have been identified as within the scope of license renewal and subject to aging management review. The components of this portion of the McGuire FP system are listed in Table 3.3-26 of the LRA. The staff is satisfied with the resolution of this issue. Open item 2.3.3.19-6 is closed. The staff's evaluation of the AMR results provided in Table 3.3-26 of the LRA is documented in Section 3.3.19.2 of this SER.

In some cases, the applicant was able to demonstrate to the staff that some FP SSCs installed in certain plant-specific areas were not credited for compliance with 10 CFR 50.48. For example, RAIs 2.3.3.19-2 and 2.3.3.19-7 address plant-specific areas for McGuire and Catawba where automatic suppression systems or hose stations were excluded from the scope of license renewal. The staff sampled portions of the SERs referenced in each plant's license condition, as well as any Duke submittals upon which the NRC staff based its review. The staff found that these suppression systems were not credited in any staff SERs or licensing documentation which form the basis of the McGuire and Catawba license conditions. Therefore, RAIs 2.3.3.19-2 and 2.3.3.19-7 were resolved because the applicant was able to demonstrate that these particular FP SCs were not credited for compliance with 10 CFR 50.48.

After determining which components were within the scope of license renewal, the staff reviewed the components the applicant identified as being subject to an AMR. The staff reviewed selected components that the applicant identified as within the scope of license renewal to verify that the applicant had identified those SCs that perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement based on qualified life or specified time period were subject to an AMR.

As documented in the conference call summary dated October 15, 2001, the staff noted that the system filters, fire extinguishers, fire hoses, and air packs were not subject to an AMR. The applicant clarified that, based on the NRC letter from C.I. Grimes to D.J. Walters, NEI, "Consumables," dated March 10, 2000, these SCs were excluded from an AMR because the applicant replaces them based on a qualified life. The applicant also noted that each SSC was identified and listed, and a site-specific evaluation for each of these SCs was included in LRA Section 2.1.2.1.2.

The staff reviewed Section 2.1.2.1.2 of the LRA and determined that filters are replaced on condition. The staff's evaluation of Section 2.1.2.1.2 and the treatment of filters is documented in Section 2.1.3.2.1 of this SER. With respect to fire extinguishers, fire hoses, and air packs, Section 2.1.2.1.2 states the following—

> Portable equipment is within the scope of license renewal but is not subject to aging management review because it is replaced on condition. Such equipment is routinely inspected for degradation. For example, fire extinguishers, self-contained breathing air packs, fire hoses and portable ductwork, credited for compliance with the Fire Protection rule, are inspected in accordance with National Fire Protection Association (NFPA) standards. These standards require replacement of portable equipment based on their condition or performance during testing and inspection. These portable components are not long-lived and are subject to replacement per NFPA standards, therefore an aging management review is not required.

As stated in Table 2.1-3 of the SRP-LR, fire extinguishers, fire hoses, and air packs are typically replaced based on performance or condition monitoring that identifies whether these components are at the end of their qualified lives. Therefore these components may be excluded, on a plant-specific basis, from AMR under 10 CFR 54.21(a)(1)(ii), however, the applicant should identify the standards that are relied on for the replacement as part of the methodology description. Since the applicant stated that these components will be replaced based on their condition or performance testing in accordance with NFPA standards, the staff finds the applicant's treatment of these consumables acceptable because it conforms to 10 CFR 54.21(a)(1)(ii).

<u>Main Fire Pump Suction Strainers</u>. The staff also reviewed mechanical components from flow diagrams LRA-M-2219, Sheet 5 and LRA-M-219, Sheet 1, and compared them to the list of components and corresponding intended function(s) presented in Table 3.4-2 of the LRA. The staff noticed that strainers associated with the main fire pumps were incorrectly excluded from an AMR. Duke identified the fire pumps and associated strainers as within the scope of license renewal by indicating that these components are designated as within the license renewal evaluation boundary, but did not list the strainers in AMR results Tables 3.3-26 or 3.3-27. The staff's view is that strainers provide a filter function to protect the integrity of the fire pumps. Appendix A to BTP 9.5-1 and Appendix A to CMEB 9.5-1 both state that "details of the fire pump installation should as a minimum conform to NFPA 20, 'Standard for the Installation of Centrifugal Pumps.' Page 6 of the Catawba response to the BTP, dated November 4, 1983, states that "fire pumps are arranged in accordance with the intent of NFPA 20-1978." The staff determined that McGuire is committed to NFPA 20, 1978 edition. NFPA-20-1978, Section 4-3.4, "Suction Strainers," requires strainers for vertical shaft fire pumps. The staff's technical concern

is that Duke uses lake water to supply its fire protection suppression systems at McGuire and Catawba. Lake water is corrosive and may contain sedimentation that can potentially clog the fire pumps. In addition, the strainers keep debris from plugging the sprinkler nozzles in fire suppression systems in the event that sprinklers are actuated.

By letter dated January 28, 2002, the staff requested the applicant, in RAI 2.3.3.19-5, to explain why these passive, long-lived components were excluded from an AMR. In its response dated April 15, 2002, the applicant confirmed that the strainers are within the scope of license renewal and stated that the strainer can be excluded from an AMR on the basis that it is actually a sub-component of the pump installed in the pump bowl, does not contain any pressure-retaining parts, and is inspected and maintained along with the other non-pressure-retaining pump sub-components. However, the staff's understanding of the main fire pumps was that they are multiple-stage pumps with clip-on strainers on the bottom (at the suction) of the pump bowl assembly. Additionally, since the strainers are relied upon to filter debris and protect the main fire pumps and sprinklers, their function is unique and distinct from that of the pump or the pump bowl. Since the strainers are removable and perform a distinct function in accordance with NFPA 20, the staff did not consider them subcomponents of the pump. Therefore, the staff considered the strainers passive, long-lived components that perform a filtration function and are subject to an AMR. This issue was characterized as SER open item 2.3.3.19-5.

In a letter dated October 28, 2002, the applicant stated that it had performed an AMR for the main fire pump strainers and provided the results of its review. These AMR results for the strainer were generically applicable to both McGuire and Catawba. Each station has three main fire pumps. The pumps are normally in standby and are automatically started on low system pressure. Each pump has a strainer that is within the scope of license renewal and is subject to an AMR because it is a long-lived, passive component. This staff is satisfied with the resolution of this issue. Open item 2.3.3.19-5 is closed. The staff's evaluation of the AMR results is documented in Section 3.3.19.2 of this SER.

With the exception of the open items discussed above, the staff did not identify any further omissions in the SCs identified by the applicant as being subject to an AMR.

2.3.3.19.3 Conclusion

On the basis of the review described above, and with the resolution of six SER open items for the fire protection systems, the staff has reasonable assurance that the applicant adequately identified those portions of the FP system that are within the scope of license renewal and the associated SCs that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.20 Fuel Handling Building Ventilation System*

In LRA Section 2.3.3.20, "Fuel Handling Building Ventilation System," the applicant identified portions of the fuel handling building ventilation (VF) system and the components that are within the scope of the LRA and subject to an AMR. In the VF system section of the LRA, the applicant stated that the VF system is further described in Section 9.4.2 of the McGuire and Catawba UFSARs.

The applicant evaluated component supports for VF system ductwork listed in Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the system in Section 2.1.2.3 of the LRA. The staff's scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff's evaluation of electrical components and instrumentation and controls in the VF system is documented in Section 2.5 of this SER.

2.3.3.20.1 Technical Information in the Application

The VF system consists of a ventilation supply air handling unit subsystem with associated dampers, ductwork, and an exhaust subsystem consisting of filter trains, associated fans, dampers, ductwork, supports, and control systems. Outside air is supplied to the fuel building area by a supply system consisting of a fan with heating and cooling coils, a filter section, and associated ductwork. The filter section contains particulate type filters. This portion of the system has no standby capacity. The fuel building supply unit normally operates continuously, but will shut down when either the filtered exhause fan is lost, a duct-mounted smoke detector is detected, or if the supply air temperature drops to 40 °F.

The VF system exhaust is an ESF. Each train of filter, fans, and motor-operated dampers is served by a separate train of the Emergency Class 1E standby power. This ensures the integrity and availability of the exhaust system in the event of any single active failure. Air exhausted from the building is monitored by a radioactive gaseous detector sampling the air in the exhaust duct header between the building and the inlet to the filter trains. Additional monitoring of exhaust air is provided in each unit vent. Indication of radioactivity above allowable limits will automatically divert the flow of air through the filter trains prior to discharge into the atmosphere through each unit vent. The VF system exhaust is available following a loss of offsite power but the fuel building supply will not be available.

In Section 2.3.3.20 of the LRA and Section 9.4.2 of the McGuire and Catawba UFSARs, the applicant identified the following VF system intended functions based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

<u>McGuire and Catawba</u>

Section 2.3.3.20 of the LRA—

- to maintain ventilation in the spent fuel pool areas to permit personnel access
- to control airborne radioactivity in the fuel pool area during normal operation, anticipated operational transients, and following postulated fuel handling accidents

Section 9.4.2 of the McGuire and Catawba UFSARs—

- to provide a suitable environment for the operation of equipment and personnel access as required for inspection, testing and maintenance
- to provide exhaust purging of the building to the unit vent
- to monitor and filter VF system exhaust air so the limits of 10 CFR Part 20 and the TS are not exceeded
- to provide a suitable environment for the operation of vital equipment during an accident

On the basis of the intended functions identified above for the McGuire and Catawba VF system, the portions of this system that were identified by the applicant as within the scope include all VF system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the portions of the VF system that are within the scope of license renewal on the flow diagrams listed in Section 2.3.3.20 of the LRA. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and classified their intended functions. The applicant provided this list in Table 3.3-28 of the LRA.

The following component types are identified as within LRA scope and subject to an AMR,and are listed in Table 3.3-28 of the LRA—air flow monitors, ductwork, filters, tubing, and valve bodies. The applicant indicated in Table 3.3-28 of the LRA that the pressure boundary function is the only applicable passive intended function of the VF system components subject to an AMR.

2.3.3.20.2 Staff Evaluation

To verify that the applicant identified the components of the VF system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagrams listed in Section 2.3.3.20 of the LRA showing the evaluation boundaries for the highlighted portion of the VF system that is within scope, and Table 3.3-28 of the LRA, which lists the mechanical components and applicable intended functions subject to an AMR. The staff reviewed Section 9.4.2 of the McGuire and Catawba UFSARs to determine if there were any portions of the VF system that met the scoping criteria in 10 CFR 54.4(a), but were not identified as within the scope of license renewal. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA,and if any structures or components that have intended functions were omitted from the list of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VF system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-28 of the LRA. The staff evaluated the scoping and screening methodology in Section 2.1 of this SER. The staff sampled structures and components from Table 3.3-28 of the LRA to verify that the applicant identified the structures and components subject to an AMR. The staff also sampled the structures and components that were within the scope of license renewal but not subject to an AMR. Based on the sample, the staff verified that these structures and components perform their intended functions without moving parts and without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VF system excluded from scope are not performing any intended functions, the staff requested additional information. The staff noted that Section 2.3.3.20 of the LRA contains a summary description of the system functions and a listing of flow diagrams. The flow diagrams highlight the evaluation boundaries and Table 3.3-28 of the LRA tabulates the components within the scope of license renewal and subject to an AMR for the

VF system. The corresponding drawings and the UFSARs, however, show additional components that were not listed in Table 3.3-28 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of fan housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant also states that cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant's basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAIs 2.3-2, 2.3-7(5), and 2.3-8(7), specific information concerning the exclusion of damper housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that dampers are not included in the AMR results tables in the LRA. The applicant added that ventilation dampers, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the damper housings are passive and long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the fuel handling building ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed, such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.20.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-4, specific information concerning the exclusion of building sealants from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that it does not classify materials such as sealants as structures or components. The applicant stated the pressure boundary function is addressed by TS surveillance testing. However, the applicant did not indicate that any of the TS surveillance requirements listed in its response were credited for aging management (and identified as AMPs). Nor did the applicant furnish a description of or information pertaining to a TS surveillance AMP (including discussion of the 10 elements of the AMP) for the staff's review.

On page 2.1-24 of the LRA, the applicant stated that "seals associated with maintaining pressure boundary are limited to the divider barrier seals in the reactor building." Since the applicant does not discuss the treatment of structural sealants other than the divider barrier seal, it is not clear to the staff that building (structural) sealants were considered during an AMR of the structure (building) for which they are a subcomponent. Furthermore, according to page 3.5-10 of the LRA, the Inspection Program for Civil Engineering Structures and Components is credited by the applicant to monitor the aging of building concrete structural components (reinforced concrete beams, columns, floor slabs, and walls). According to Section B.3.21 of the LRA, the scope of the Inspection Program for Civil Engineering Structures and Components does not include structural sealants. Table 2.1-3, on page 2.1-15 of the SRP-LR, states that an applicant's structural AMP is expected to address structural sealants "with respect to an AMR program." The intent of this statement is that an applicant's structural AMP is expected to manage or monitor the aging effects of the structure and associated subcomponents that are identified during the AMR. The basis for this SRP guidance is documented in the summary (issued January 21, 2000) of a December 8, 1999, meeting to discuss the staff's position on the treatment of consumables. This summary clearly states, on page 3, that structural sealants would be implicitly included at the component level and considered during the AMR. Since the structural AMP identified for the concrete structural components does not address structural sealants, and since that applicant did not identify the TS surveillances listed in its response as AMPs or provide appropriate information to support the staff's review of these surveillances as AMPs, the staff characterized this issue as SER open item 2.3-3.

In its response to this open item, dated October 28, 2002, the applicant credited a visual inspection of the structural sealant used to maintain ventilation pressure boundary integrity of the control room area, emergency core cooling pump rooms, annulus, and fuel handling building. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open item 2.3-3. The staff's evaluation of the Ventilation Area Pressure Boundary Sealants Inspection Program is provided in Section 3.0.3.19 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-3, specific information concerning the exclusion of housings for radiation monitors, smoke detectors, air flow monitors, and chlorine monitors from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that, based on guidance provided in NEI 95-10, Revision 3, radiation monitors, smoke detectors, and chlorine detectors are not considered passive components and are therefore not subject to an AMR. Because the monitors and detectors do not perform an intended function, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAIs 2.3-8(6) and 2.3-9(3), specific information concerning the exclusion of housings for filters from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant clarified that filter housings are within license renewal evaluation boundaries, although the filter media are excluded because filters are replaced on condition. The staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-5, specific information concerning the exclusion of passive components associated with ductwork from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant identified these passive components as subcomponents of ductwork. The applicant also stated that ventilation grilles were installed only for aesthetic purposes and perform no intended license renewal function. The staff finds the applicant's response acceptable based on the information provided related to passive components associated with ventilation ductwork.

Some components that are common to many systems, including the VF system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this report, the staff evaluated component supports for piping, cables, and equipment that supported the design and operation of the VF system. In Section 2.5 of the LRA titled, "Scoping and Screening Results - Electrical and Instrumentation and Controls," the staff evaluated electrical and instrument components that support the operation of the VF system.

The staff reviewed the LRA, information in the UFSARs, and the applicant's RAI responses. In addition, the staff sampled several components from the VF system flow diagrams, as identified in Section 2.3.3.1 of the LRA, to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

2.3.3.20.3 Conclusions

On the basis of its review, and with the resolution of the open items identified in this SER section, the staff has reasonable assurance that the applicant has adequately identified the VF system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.21 Groundwater Drainage System*

In LRA Section 2.3.3.21, "Groundwater Drainage System," the applicant described the components of the groundwater drainage system that are within the scope of license renewal and subject to an AMR. Sections 9.5.11 and 9.5.8 of the Catawba and McGuire UFSARs, respectively, provides additional information concerning their respective groundwater drainage systems.

2.3.3.21.1 Technical Information in the Application

The groundwater drainage systems are identical for purposes of license renewal for both facilities without any notable differences in system design. The groundwater drainage system prevents hydrostatic loads on the reactor and auxiliary building substructures. The groundwater drainage system maintains an acceptable groundwater level for the Auxiliary Building by transferring water out of the Auxiliary Building and mitigates the consequences of certain postulated flooding events. The applicant described its process for identifying the mechanical components within the scope of license renewal in Section 2.1.1, "Scoping Methodology," of the LRA. On the basis of its methodology described above, the applicant identified portions of the groundwater drainage system that are within the scope of license renewal on the flow diagrams listed in Section 2.3.3.21 of the LRA. Using the methodology described in Section 2.1.2, "Screening Methodology," of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire groundwater drainage systems are listed in LRA Table 3.3-29. In the LRA, Table 3.3-29, the applicant lists the following five component types as subject to an AMR—pipe, pump casings, orifices (Catawba only), tubing, and valve bodies. The applicant states that maintaining pressure boundary integrity is the only intended function of the SCs subject to an AMR.

2.3.3.21.2 Staff Evaluation

The staff reviewed Section 2.3.3.21 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the components of the Catawba and McGuire groundwater drainage systems that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.21 of the LRA and the Catawba and McGuire UFSARs to determine if the applicant adequately identified the SSCs of the groundwater drainage system that are in the scope of license renewal. The staff verified that those portions of the groundwater drainage system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.3.21 of the LRA. The staff then focused its review on those portions of the groundwater drainage system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSARs to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the groundwater drainage system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the groundwater drainage system that are identified as within the scope of license renewal. The applicant identified and listed the SCs subject to an AMR for the groundwater drainage systems in Table 3.3-29 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determined as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the groundwater drainage system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes meet at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the groundwater drainage system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

2.3.3.21.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.21 of the LRA and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the groundwater drainage systems that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.22 Hydrogen Bulk Storage System*

2.3.3.22.1 Technical Information in the Application

The hydrogen bulk storage system supplies hydrogen to the volume control tank (VCT). The hydrogen bulk storage system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2).

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba hydrogen bulk storage systems are listed in Table 3.3-30 of the LRA. The component types that were identified in the table are pipe, tubing (Catawba only), and valve bodies. The applicant states that maintaining pressure boundary integrity is the only intended function of the components subject to an AMR.

2.3.3.22.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the hydrogen bulk storage system, and associated pressure boundary components and supporting structures within the scope of license renewal and subject to an AMR, have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the hydrogen bulk storage system and associated pressure boundary components and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed the structures and components that were identified as not being within the scope of license renewal to verify that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a). For those structures and components that have applicable intended functions, the staff sought to verify that they either perform these functions with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

The staff did not identify any omissions.

2.3.3.22.3 Conclusions

On the basis of its review of the information presented in Section 2.3.3.22 of the LRA and the supporting information in the McGuire and Catawba UFSARs, the staff did not find any omissions by the applicant. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the hydrogen bulk storage system, and the associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.23 Instrument Air System*

In LRA Section 2.3.3.23, “Instrument Air System,” the applicant identified the instrument air system as one that is within the scope of license renewal and subject to an AMR. This section refers to LRA Table 3.3-31, which lists the mechanical components, component functions, and materials of construction of the McGuire and Catawba instrument air system that are subject to an AMR. This system is further described in Section 9.3.1 of the McGuire and Catawba UFSARs. The function of this system is similar for both facilities with some differences in system design. Any notable differences are specifically identified and discussed in the staff’s evaluation. Unless otherwise specified, the information provided below is applicable to both the Catawba and the McGuire instrument air system.

2.3.3.23.1 Technical Information in the Application

The function of the instrument air system is to provide dry, oil-free compressed air for all air-operated instrumentation and valves for each unit at Catawba and McGuire. At McGuire, the instrument air system consists of three centrifugal compressors and three reciprocating compressors. The six compressors are oil free. The centrifugal compressors operate in “base mode,” supplying all plant instrument air demands. The reciprocating compressors operate in “standby mode” and start on decreasing air pressure. At Catawba, instrument air is supplied by three centrifugal air compressors. Two centrifugal compressors operate “base loaded” to supply the normal requirements of the instrument air system. The third centrifugal compressor is used for standby service. The compressors’ intakes at Catawba and McGuire are in the service building basement, and at both stations, the instrument air system is a subsystem of the compressed air system. The applicant described its process for identifying the mechanical components that are within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology.” The applicant identified component types for the instrument air system that require an AMR. These are listed in LRA Table 3.3-31 for both Catawba and McGuire, along with the passive function, the aging effect, and the aging management program activities to be applied.  The applicant identified the following component types for the Catawba and McGuire instrument air system that are subject to an AMR—filter housings (McGuire only), supply accumulators (McGuire only), instrument air tanks (McGuire only), pipe, tubing, and valve bodies.  The applicant further identified the only intended function of these component types to be maintaining the integrity of the instrument air system pressure boundary.

The applicant utilized a screening process to generate piping and instrumentation diagrams (P&IDs) applicable to the LRA.  During initial scoping, the applicant identified plant systems and structures that were candidates for inclusion within the scope of 10 CFR Part 54.  For systems and structures that were "scoped in," screening was then performed to identify the passive components and structural members that support an intended function of the in-scope system or structure.  These systems and structures are then subject to an AMR in accordance with 10 CFR 54.21(a).  The results of the screening review were used to generate the P&IDs, which show components that are subject to an AMR as highlighted and marked by flags.

2.3.3.23.2 Staff Evaluation

The staff reviewed Sections 2.1 and 2.2 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the Catawba and McGuire instrument air system that are within the scope of license renewal in accordance with 10 CFR 54.4.  The staff reviewed Section 2.3 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the systems and structures of the instrument air system that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text, tables, and diagrams submitted by the applicant in Section 2.3 of the LRA, and the Catawba and McGuire UFSARs, to determine whether any systems and structures of the instrument air system that may have been omitted from the scope of license renewal meet the scoping criteria in 10 CFR 54.4.  The staff verified that those portions of the instrument air system identified by the applicant as meeting the scoping requirements of 10 CFR 54.4, do in fact meet these requirements for both stations.  The staff then focused its review on those portions of the instrument air system that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4.  The staff also reviewed the UFSARs to identify system functions that were not included in the LRA and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.  Therefore, there is reasonable assurance that the applicant adequately identified all portions of the Catawba and McGuire instrument air system that are within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the in-scope systems and structures that are subject to an AMR in accordance with 10 CFR 54.21(a).  The applicant identified the systems and structures that are subject to an AMR for the instrument air system and listed them in Table 3.3-31 for both Catawba and McGuire.  The staff performed its review by sampling the systems and structures that the applicant identified as within the scope of license renewal, but not subject to an AMR, to verify that these systems and structures perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period.   All systems and structures reviewed by the staff met the above criteria for both Catawba and McGuire.

In Section 2.3.3.23, “Instrument Air System,” of the LRA, the applicant lists 25 P&IDs for McGuire and 5 for Catawba that were marked to indicate the license renewal evaluation boundary for the instrument air system. The staff compared the P&IDs to the system drawings and descriptions in the UFSARs to ensure that the diagrams were representative of the instrument air system for the respective plant. The applicant highlighted and flagged components on the P&IDs that are subject to an AMR. The staff sampled portions of the P&IDs that were not highlighted to ensure these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

2.3.3.23.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.23 of the LRA, the supporting information in the Catawba and McGuire UFSARs, and the P&IDs, as described above, the staff did not identify any omissions in the scoping and screening of the Catawba and McGuire instrument air system by the applicant. Therefore, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the Catawba and McGuire instrument air system that are within the scope of license renewal, and the systems and structures that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.24 Liquid Waste System*

In LRA Section 2.3.3.24, “Liquid Waste System,” the applicant described the components of the liquid waste system that are within the scope of license renewal and subject to an AMR. This system is described in Section 11.2 of the McGuire and Catawba UFSARs.

2.3.3.24.1 Technical Information in the Application

The liquid waste system collects, segregates, and processes all radioactive and potentially radioactive liquids generated in the plant to control and minimize releases of radioactivity to the environment.

The applicant described the process for identifying the mechanical components that are within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology.” As described in the scoping methodology, the applicant identified the portions of the liquid waste system that are within the scope of license renewal on the P&IDs that are listed in LRA Section 2.3.3.24. Consistent with the method described in LRA Section 2.1.2, “Screening Methodology,” the applicant listed the liquid waste system mechanical components that are subject to an AMR in LRA Table 3.3-32. This table also lists the component functions. Specifically, the applicant identified the following components as subject to an AMR—valve bodies, piping, motor-driven auxiliary feedwater pump sump pumps (for Catawba only), residual heat removal pump and containment spray pump room sump pumps (for Catawba only), orifice (for Catawba only), separators (for Catawba only), strainers (for Catawba only), turbine-driven auxiliary feedwater pump sump pumps (for Catawba only), tubing (for Catawba only), and waste drain tanks (for Catawba only). All these components have the intended component function of PB, which is defined by the applicant as maintaining pressure boundary, affecting containment isolation, or preventing interaction with safety-related equipment. In addition to the PB function, separators and strainers have the FI (filtration) function.

2.3.3.24.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.24 to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the liquid waste system that are within the scope of license renewal in accordance with 10 CFR 54.4(a), and that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information provided in LRA Section 2.3.3.24, the applicable P&IDs referenced therein, and the McGuire and Catawba UFSARs to determine if the applicant adequately identified the portions of the liquid waste system that are within the scope of license renewal. The staff verified that those portions of the liquid waste system that meet the scoping requirements of 10 CFR 54.4(a) were included within the scope of license renewal and were identified by the applicant in Section 2.3.3.24 of the LRA.

In LRA Section 2.3.3.24, the applicant listed applicable P&IDs for the liquid waste system. The detailed diagrams are highlighted to identify those portions of the system that are within the scope of license renewal. The staff compared the LRA diagrams to the system drawings and descriptions in the UFSARs to ensure that the diagrams were representative of the liquid waste system. To verify that the applicant included the applicable portions of the liquid waste system within the scope of license renewal, the staff focused its review on those portions of the liquid waste system that were not identified as within the scope of license renewal and verified that they did not meet the scoping criteria of 10 CFR 54.4(a). In addition, the staff reviewed the UFSARs for each facility to identify any additional system functions that were not identified in the LRA, and verified that no additional functions met the scoping requirements of 10 CFR 54.4(a). Based on the experience of reviewing the previous LRAs, the staff recognized that the radioactive waste management function of the radwaste systems, in general, did not meet the scoping requirements of 10 CFR 54.4(a) because the dose consequences of a failure would be much lower than the dose limits specified in 10 CFR 54.4(a)(1)(iii). However, other plant-specific system functions (such as containment isolation) may meet some of the requirements in 10 CFR 54.4(a). LRA Section 2.3.3.24 describes the radioactive waste management function of the system, but does not identify which system functions meet the requirements in 10 CFR 54.4(a).

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.24-1, the applicant to identify the intended system functions of the liquid waste system that the applicant used for its scoping determination. In its response dated April 15, 2002, the applicant stated that the system intended functions were not used to determine whether the liquid waste system is within the scope of license renewal. Instead, the applicant determined the portions of the liquid waste system within the scope of license renewal according to the following scoping criteria—(1) portions of the systems that are safety-related (Duke Class A, B, or C), (2) portions of the systems that are designated as non-safety-related Class F piping, (3) portions of the systems that are required to remain functional for fire protection and station blackout, and (4) portions of the systems that are environmentally qualified. The staff finds this response consistent with the methodology described in Section 2.1 of the LRA, which the staff evaluated and found acceptable (refer to Section 2.1.3.1 of this SER). However, the staff sought to understand whether or not equipment that performs the radioactive waste management function of this system was identified by the applicant as within the scope of license renewal.

To accomplish this, the staff reviewed Section 3.2.2 of the McGuire UFSAR, which indicates that portions of the radioactive waste management systems whose failure would adversely affect the health and safety of the public are upgraded to Duke Class C. The staff also reviewed Catawba UFSAR Section 3.2.2, which states that portions of the radioactive waste management systems whose failure would result in dose consequences greater than 0.5 rem to the whole body or equivalent offsite doses are upgraded to Duke Class C. The applicant included Duke Class C piping and components within the scope of license renewal. The dose criteria in 10 CFR 54.4(a)(1)(iii) are exposures comparable to the guidelines in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11. The dose limits specified in the above regulations are 25 rem to the whole body or 300 rem to the thyroid. The applicant's scoping criteria for radioactive waste management systems are more conservative than the criterion specified in 10 CFR 54.4(a)(1)(iii) and, therefore, are acceptable. On the basis of the information in the RAI responses and the UFSARs, the staff verified that portions of the radioactive waste management system that met the scoping criteria of 10 CFR 54.4 were within the scope. Therefore, the staff's question in RAI 2.3.3.24-1 was resolved. The staff's evaluation also resolves a similar concern identified in RAI 2.3.3.38-2 for the waste gas system (see Section 2.3.3.38.2 of this SER).

Table 3-4 of the McGuire and Catawba UFSARs indicates that the reactor coolant drain tank heat exchanger and the groundwater drainage sump pump of the liquid waste system are safety-related. However, the staff was not able to find these components listed in LRA Section 2.3.3.24 as within the scope of the license renewal. Through a cross-system review, the staff found that the shells of the reactor coolant drain tank heat exchanger were included in the component cooling system (LRA Section 2.3.3.5) as within the scope of license renewal and subject to an AMR. The pump casing of the groundwater drainage sump pump was included in the groundwater drainage system (LRA Section 2.3.3.21) as within the scope of license renewal and subject to an AMR. In addition, the staff noted that one of the liquid waste system flow diagrams, CN-1565-1.3, contains highlighted piping and valves, but the diagram is not listed in LRA Section 2.3.3.24. Through a cross-system review, the staff found that this drawing and these highlighted components were included in LRA Section 2.3.3.28, “Nuclear Service Water System.” The staff found that the applicant had properly included the above components within the scope of license renewal and subject to an AMR. However, the LRA does not have the above cross-references.

In reviewing the AMR results tables for this system, the staff noticed that more components (such as sump pumps, orifices, separators, strainers, tubing, and waste drain tank) were listed for Catawba than for McGuire. The staff believed that the scoping differences resulted from design differences between Catawba and McGuire, but could not understand the design differences when it compared the system descriptions in the respective UFSARs for McGuire and Catawba. In a conference call on September 12, 2001, summarized in a memorandum dated October 10, 2001, the staff asked the applicant to explain the differences in design between Catawba and McGuire because of which components, such as sump pumps, orifices, separators, strainers, tubing, and waste drain tank, were determined to be within the scope of license renewal for Catawba but not for McGuire. The applicant explained that a significant portion of the liquid waste system was credited in Catawba’s design basis for removing discharged fire water system inventory from flooded areas during and following fire water actuation to prevent safety-related equipment from flood-induced failure. The design basis for McGuire did not include this provision. In addition, there are more non-safety-related pipe runs (Class F) at Catawba than at McGuire, and the failure of these pipe runs at Catawba might adversely impact safety-related equipment. Therefore, more components of the liquid waste system were determined to be within the scope of license renewal at Catawba than at McGuire. The applicant's discussion of the system design differences between Catawba and McGuire provided a reasonable explanation of the differences in scoping for the liquid waste system. On the basis of its review, the staff did not identify any omissions in the applicant's scoping of mechanical components according to 10 CFR 54.4(a).

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the liquid waste system that were identified as within the scope of license renewal. The applicant used the screening methodology described in LRA Section 2.1.2 to identify the SCs subject to an AMR. The staff evaluation of the scoping and screening methodology is documented in Section 2.1 of this SER. In the LRA, the applicant identified the portions of the liquid waste system that are within the scope of license renewal in the P&IDs and listed the mechanical components that are subject to an AMR and their intended component functions in LRA Table 3.3-32. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions by the applicant in screening SCs according to 10 CFR 54.21(a)(1).

2.3.3.24.3 Conclusions

On the basis of its review of the information contained in LRA Section 2.3.3.24, the supporting information in the P&IDs, and the McGuire and Catawba UFSARs, as described above, the staff did not identify any omissions by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant adequately identified those portions of the liquid waste system that are within the scope of license renewal and the associated SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.25 Miscellaneous Structures Ventilation System*

In LRA Section 2.3.3.25, "Miscellaneous Structures Ventilation System," the applicant identified components of the Catawba miscellaneous structures ventilation (VK) system that are within the scope of license renewal and subject to an AMR. This specific system is only applicable to Catawba. The applicant further stated in Section 2.3.3.25 of the LRA that the McGuire turbine building ventilation system performs the same functions as the Catawba VK system.

The applicant evaluated component supports for equipment, piping, ductwork, and instrument lines within this system in Section 2.4.3 and Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the system in Section 2.1.2 of the LRA. The staff's scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff's evaluation of electrical components and instrumentation and controls in the VK system is documented in Section 2.5 of this SER.

2.3.3.25.1 Technical Information in the Application

The Catawba VK system includes the standby shutdown facility (SSF) heating ventilation and air-conditioning subsystems. The SSF heating ventilation and air-conditioning portion of the VK system provides the environmental controls necessary to ensure that SSF equipment is maintained operable during postulated fires and station blackout. The mechanical components subject to an AMR, their intended functions, and the materials of construction for the SSF heating ventilation and air-conditioning portion of the Catawba VK system are listed in Table 3.3-33 of the LRA. A Catawba flow diagram (CN-1579-4.3) has been highlighted to indicate the LRA evaluation boundary for the SSF heating ventilation and air-conditioning portion of the Catawba VK system.

In Section 2.3.3.25 of the LRA, the applicant identified the following Catawba VK system intended function based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

- to provide the environmental controls necessary to ensure that standby shutdown facility equipment is maintained operable during postulated fires and station blackout

The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the portions of the VK system that are within the scope of license renewal on the flow diagram listed in Section 2.3.3.25 of the LRA. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 3.3-33 of the LRA.

The following component types are identified as within the scope of license renewal and subject to an AMR and are listed in Table 3.3-33—air handling unit, ductwork, flexible connectors, and plenum section. The applicant indicated in Table 3.3-33 of the LRA that the VK system pressure boundary function is the only applicable intended function subject to an AMR.

2.3.3.25.2 Staff Evaluation

To verify that the applicant identified the components of the VK system that is within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.25 of the LRA. The diagram highlights the evaluation boundaries for the portions of the VK system that are within the scope of license renewal. The staff reviewed Table 3.3-33 of the LRA, which lists the mechanical components and the applicable intended functions subject to an AMR, and Table 3-4 of the Catawba UFSAR to determine if there were any portions of the VK system that met the scoping criteria in 10 CFR 54.4(a) but were not identified in the LRA. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA and if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VK system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-33 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this report. The staff sampled the structures and components listed in Table 3.3-33 of the LRA to verify that the applicant did identify the structures and components subject to an AMR. The staff also sampled the structures and components that are within the scope of license renewal but not subject to an AMR. Based on this sample, the staff verified that these structures and components perform their intended functions without moving parts and without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

The NRC staff noted that Section 2.3.3.25 of the LRA provides a summary description of the system functions and specified a flow diagram. The flow diagram highlights the evaluation boundaries, and Table 3.3-33 of the LRA lists the components of the VK system within the scope of license renewal and subject to an AMR. The corresponding drawings and the UFSARs, however, show additional components that were not listed in Table 3.3-33 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-9, specific information concerning the exclusion of Catawba refrigerant coils serving the shutdown panel areas from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated the refrigerant coils associated with the auxiliary shutdown panel room air-conditioning sub system are within the scope of license renewal and should have been highlighted on flow diagram CN-1577-1.8. The coils are listed in AMR Table 3.3-1 with tubes, tube sheets, shells, and bonnets. On the basis of the information provided, the staff finds the applicant’s response acceptable.

Some components that are common to many systems, including the VK system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff’s evaluation of applicant’s treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this report, the staff evaluated component supports for piping, cables, and equipment, which are discussed in LRA Section 2.4 titled, "Scoping and Screening Results: Structures." In Section 2.5 of this report, the staff evaluated electrical components that support the operation of the VK system. These are discussed in LRA Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls."

The staff reviewed the LRA and supporting information in the Catawba UFSAR. In addition, the staff sampled several components from the VK system flow diagram, as identified in Section 2.3.3.25 of the LRA, to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAI.

2.3.3.25.3 Conclusions

On the basis of its review, the staff has reasonable assurance that the applicant has adequately identified the Catawba VK system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.26 Nitrogen System*

In LRA Section 2.3.3.26, “Nitrogen System,” the applicant identified the nitrogen system as being within the scope of license renewal and subject to an AMR. This section references Table 3.3-34 of the LRA, which lists mechanical components, component functions, and materials of construction that are subject to an AMR for the McGuire and Catawba nitrogen system. This system is non-safety-related for Catawba. For McGuire, a part of the nitrogen system is safety-related. The function of the nitrogen system is similar for both facilities with some differences in system design. Any notable differences are specifically identified and discussed in the staff's evaluation. Unless otherwise specified, the information provided below is applicable to both the Catawba and McGuire nitrogen system.

2.3.3.26.1 Technical Information in the Application

The function of the nitrogen system is to provide a supply of nitrogen to valves that have pneumatic actuators. For McGuire, the nitrogen system provides a safety-related supply of nitrogen to the pneumatic actuators on the feedwater isolation valves. The applicant has indicated that for Catawba, the nitrogen system is a non-safety-system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The applicant described its process for identifying the mechanical components that are within the scope of license renewal in LRA section 2.1.1, "Scoping Methodology." The applicant identified component types for the nitrogen system that require AMR. These are listed in LRA Table 3.3-34 for both Catawba and McGuire, along with the passive function, the aging effect, and the aging management program activities to be applied. The applicant identified the following component types for the Catawba and McGuire nitrogen system that are subject to an AMR—nitrogen supply tanks (McGuire only), pipe, tubing (McGuire only), and valve bodies. The applicant identified the only intended function of these component types to be maintaining the integrity of the nitrogen system pressure boundary.

The applicant utilized a screening process to generate P&IDs applicable to the LRA. During initial scoping, the applicant identified plant systems and structures that were candidates for inclusion within the scope of 10 CFR Part 54. For systems and structures that were "scoped in," screening was then performed to identify the passive components and structural members that support an intended function of the in-scope system or structure. These systems and structures are then subject to an AMR in accordance with 10 CFR 54.21(a). The results of the screening review were used to generate the P&IDs which show components that are subject to an AMR as highlighted and marked by flags.

2.3.3.26.2 Staff Evaluation

The staff reviewed Sections 2.1 and 2.2 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the Catawba and McGuire nitrogen systems that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed Section 2.3 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the systems and structures of the nitrogen system that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text, tables, and diagrams submitted by the applicant in Section 2.3 of the LRA and the Catawba and McGuire UFSARs to determine whether any systems and structures of the nitrogen system that may have been omitted from the scope of license renewal meet the scoping criteria in 10 CFR 54.4. The staff verified that those portions of the nitrogen system identified by the applicant as meeting the scoping requirements of 10 CFR 54.4 do in fact meet these requirements for both stations. The staff then focused its review on those portions of the nitrogen system that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSARs to identify system functions that were not included in the LRA and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the Catawba and McGuire nitrogen systems that are within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the in-scope systems and structures that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the systems and structures that are subject to an AMR for the nitrogen system and listed them in Table 3.3-34 for both Catawba and McGuire. The staff performed its review by sampling the systems and structures that the applicant identified as within the scope of license renewal, but not subject to an AMR, to verify that these systems and structures perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period. All systems and structures reviewed by the staff met the above criteria for both Catawba and McGuire.

In Section 2.3.3.26, “Nitrogen System,” of the LRA, the applicant listed four P&IDs for McGuire and one for Catawba that were marked to indicate the license renewal evaluation boundary for the nitrogen system. The applicant highlighted and flagged components on the P&IDs that are subject to an AMR. The staff sampled portions of the P&IDs that were not highlighted to ensure these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

Catawba P&ID CN-1602-1.0, “Nitrogen System,” depicts nitrogen supply lines that are not in scope supplying pressure for the NW. The NW system prevents leakage of containment atmosphere past certain CIVs following a LOCA by injecting seal water at a pressure exceeding containment accident pressure between the two seating surfaces of the CIVs. The water that gets injected comes from one of two trains of surge chambers depicted on P&ID CN-1602-1.0 as being pressurized by nitrogen. The nitrogen pressure drives the water between the valves. Section 6.2.4.2.2 of the Catawba UFSAR states that the NW system is designed to meet all regulatory and testing requirements set forth in paragraph III-C of 10 CFR Part 50, Appendix J, and ASME Code Section IX. Following a LOCA, containment isolation would be required on an ongoing basis for an extended period of time. The staff believed this function of the nitrogen system to fall under the scoping requirements of 10 CFR 54.4(a)(2) for non-safety-related systems “whose failure could prevent satisfactory accomplishment of functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.” In this case paragraph (iii) (the capability to mitigate the consequences of accidents...) appeared to apply. The staff concluded that the nitrogen supply piping up to the containment valve injection water surge chambers and the surge chambers, depicted on CN-1602-1.0, should be included in the evaluation boundary for AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.26, the applicant to provide the basis for not including these components in scope.

In its response dated April 15, 2002, the applicant indicated that the nitrogen “overpressure” on the NW system is used only under normal operating conditions and not relied upon during a design basis event. The applicant further indicated that during a design basis event, the nuclear service water system is relied upon to inject seal water at a pressure exceeding containment accident pressure between the two seating surfaces of the CIVs. The applicant indicated that the nuclear service water system essential header piping is highlighted to show that it is within the scope of license renewal. The staff verified this by inspecting P&IDs CN-1574-2.4, “Flow Diagram of Nuclear Service Water System,” and CN-1569-1.0, “Flow Diagram of Containment valve Injection Water System.” The staff finds that the applicant has appropriately identified the nuclear service water piping as in scope for the above safety function, and that the nitrogen supply lines discussed above are not in scope because they do not support a safety-related function.

The staff’s review of the Catawba UFSAR indicated that a PORV is provided in the safety grade portion of each main steam line upstream of the isolation valve. These PORVs are required to achieve and maintain a hot-shutdown condition and are therefore safety-related. The safety grade mode of operation of the PORVs is provided by the use of an environmentally and seismically qualified nitrogen control system. Nitrogen is supplied by seismically mounted cylinders located in the “doghouse.” The staff noted that these cylinders, and the piping between them and the main steam line PORVs, are apparently not depicted on any nitrogen system drawing. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.26-2, clarification of the status of this run of piping and the nitrogen cylinders (i.e., whether or not they were in scope). In its response dated April 15, 2002, the applicant confirmed that the Catawba main steam line PORVs are supplied with a nitrogen control system as a backup to the normal instrument air supply. This backup nitrogen control system consists of valves, tubing, and nitrogen bottles. The applicant supplemented Table 3.3-34 with the AMR results for valve bodies and tubing associated with this backup nitrogen control system. The staff’s evaluation of the AMR results are documented in Section 3.3.26.2.1 of this SER. The applicant stated that the nitrogen bottles are periodically replaced and, therefore, are not subject to an AMR. However, the applicant did not specify the details of the periodic replacement. Since the staff could not determine if the nitrogen bottles are replaced based on qualified life or on condition in accordance with performance criteria or a governing program, the applicant provided supplemental information in electronic correspondence dated July 16, 2002 (ADAMS Accession No. ML023290649). In this correspondence, the applicant stated the following—

> Catawba TS surveillance requirement (TSSR) 3.7.4.1 requires verification that one of the nitrogen bottles on each SG PORV is pressurized to greater than 2100 psig once every 24 hours. This TSSR is performed with a Catawba procedure entitled "Procedure for Checking and Replacing Steam Generator PORV Nitrogen Cylinders and Setting Cylinder Regulators." There are two nitrogen cylinders per SG PORV. Initial pressure in each cylinder is greater than 2500 psig. This procedure requires that if the pressure in either nitrogen cylinder is less than or equal to 2420 psig, then the nitrogen cylinder is replaced. Replacement cylinders are obtained from a warehouse. The used cylinders are returned to the warehouse. The cylinders are not permanently installed in the plant.

The applicant further stated that replacement of the nitrogen cylinders is based on gas pressure and, therefore, performance monitoring consistent with the SRP-LR. Pending the staff’s receipt of this information in official correspondence, this issue was characterized as SER confirmatory item 2.3.3.26.2-1. In its response to this confirmatory item, dated October 28, 2002, the applicant formally provided the information that had been furnished in electronic correspondence. The staff finds that the response provides an acceptable basis for excluding these nitrogen bottles from an AMR. Therefore, confirmatory item 2.3.3.26.2-1 is closed.

On Catawba P&ID CN-1602-1.0, “Nitrogen System,” at the lower right hand corner of the drawing, an independent nitrogen system is depicted as not in scope. The system is shown supplying actuators 1CF42, 1CF51, 1CF33, and 1CF60. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.26-3, the applicant to identify the function of the system. Also, at the point on the P&ID where the nitrogen system is shown supplying the actuators listed, the diagram references "Note 8." Note 8 was missing from the P&ID. The RAI also requested the applicant to provide Note 8. In its response dated April 15, 2002, the applicant indicated that the independent nitrogen system depicted on P&ID CN-1602-1.0 has no function and, in fact, has been abandoned. The applicant also indicated that since the time the P&IDs were highlighted for license renewal, P&ID CN-1602-1.0 was revised to show the independent nitrogen system as cut and capped, nitrogen bottles removed, and the system abandoned in place with Note 10 added to indicate this status. The staff's question regarding Note 8 is moot because the system has been abandoned. The staff finds this response acceptable.

2.3.3.26.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.26 of the LRA, the supporting information in the Catawba and McGuire UFSARs, and the P&IDs, as described above, the staff did not identify any other omissions in the scoping and screening of the Catawba and McGuire nitrogen system by the applicant. Therefore, the staff concludes that, with the resolution of confirmatory item 2.3.3.26.2-1, there is reasonable assurance that the applicant has identified those portions of the Catawba and McGuire nitrogen system that are within the scope of license renewal, and the systems and structures that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.27 Nuclear Sampling System*

In LRA Section 2.3.3.27, "Nuclear Sampling System," the applicant described the components of the nuclear sampling system that are within the scope of license renewal and subject to an AMR. Section 9.3.2 of the Catawba and McGuire UFSARs provides additional information concerning their respective nuclear sampling systems.

2.3.3.27.1 Technical Information in the Application

The nuclear sampling systems are essentially the same and perform the same function at Catawba and McGuire. The system provides a means of obtaining the more frequently taken samples during normal plant operation from the station's nuclear-safety-related systems in a convenient, shielded, and safe environment. The system also provides a means of sampling the reactor coolant and containment atmosphere following a LOCA to monitor the reactor and determine the degree of core damage. The mechanical components subject to an AMR, their intended functions, and materials of construction for the nuclear sampling system are listed in Table 3.3-35. Using the methodology described in LRA Section 2.1.2, "Screening Methodology," the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. In LRA Table 3.3-35, the applicant lists the following four component commodity groups as subject to an AMR—pipe, orifices, tubing, and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. The orifices also perform a throttling function.

2.3.3.27.2 Staff Evaluation

The staff reviewed Section 2.3.3.27 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the nuclear sampling system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.27 of the LRA and the Catawba and McGuire UFSARs to determine if the applicant adequately identified the SSCs of the nuclear sampling system that are in the scope of license renewal. The staff verified that those portions of the nuclear sampling system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified by the applicant in Section 2.3.3.27 of the LRA. The staff then focused its review on those portions of the nuclear sampling system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSARs to determine if there were any additional system functions that were not identified in the LRA, and verified that no additional function met the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the nuclear sampling system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the nuclear sampling system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the nuclear sampling systems in Table 3.3-35 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, and were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the nuclear sampling system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes meets at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the nuclear sampling system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

2.3.3.27.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.27 of the LRA and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the nuclear sampling system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.28 Nuclear Service Water System*

In Section 2.3.3.28, "Nuclear Service Water System," of the LRA, the applicant identified the nuclear service water system (NSW) as one that is within the scope of license renewal and subject to an AMR. This section refers to LRA Tables 3.3-36 and 3.3-37, which lists mechanical components, component functions, and materials of construction subject to an AMR, for both the McGuire and Catawba nuclear service water systems. This system is further described in Section 9.2.2 of the McGuire UFSAR and in Section 9.2.1 of the Catawba UFSAR. This system is similar for both facilities with some differences in system design. Any notable differences are specifically identified and discussed in the staff's evaluation. Unless otherwise specified, the information provided below is applicable to both the Catawba and McGuire nuclear service water systems.

2.3.3.28.1 Technical Information in the Application

The applicant identified the piping and mechanical components of the NSW system for Catawba and McGuire in the LRA. The NSW system at Catawba and McGuire provides cooling water for various safety-related and non-safety related heat loads. The system at both Catawba and McGuire provides two redundant "essential headers" serving two trains of equipment necessary for safe shutdown, and a "non-essential header" serving equipment not required for safe shutdown. The NSW system is designed to meet design flow rates and heads for normal station operation, and also those required for safe shutdown normally or as the result of a postulated LOCA. The ultimate heat sink for McGuire consists of Lake Norman and the standby nuclear service water (SNSW) pond. The ultimate heat sink for Catawba consists of Lake Wylie and the standby nuclear service water pond.

The applicant described its process for identifying the mechanical components that are within the scope of license renewal in Section 2.1.1, "Scoping Methodology," of the LRA. The applicant stated in Section 2.3.3.28 of the LRA that the McGuire NSW system acts as an assured source of makeup water for various requirements and the normal supply of water for the containment ventilation cooling water system. The applicant further stated in this section for Catawba that the NSW system supplies emergency makeup water to various safety-related systems during normal operation and design basis events, water for fire protection hose stations in the diesel buildings and nuclear service water pumphouse, and cooling flow and flush water for non-QA heat loads and functions during normal operation. The applicant identified component types for the McGuire and Catawba NSW system that require AMR. These are listed in LRA Table 3.3-36 for McGuire, along with the passive function, the aging effect, and the aging management program activities to be applied. The applicant identified the following component types for the McGuire NSW system that are subject to an AMR—oil coolers (tubes, tube sheets, shells, and channel heads), expansion joints, pump casings, strainers, orifices, pipe, tubing, and valve bodies. The applicant further identified the intended function of these component types, in Table 3.3-36 of the LRA, to be maintaining the integrity of the NSW system pressure boundary, throttling flow, and transferring heat. Component types for the Catawba NSW system that require AMR are presented in Table 3.3-37 of the LRA. The applicant identified the following component types for the Catawba nuclear service water system that are subject to an AMR—annubars, flexible hoses, manways, pump casings, orifices, pipe, strainers, tubing, and valve bodies. The applicant further identified the intended function of these component types, in Table 3.3-37 of the LRA, to be maintaining the integrity of the NSW system pressure boundary and throttling flow.

The applicant utilized a screening process to generate P&IDs applicable to the LRA. During initial scoping, the applicant identified plant systems and structures that were candidates for inclusion within the scope of 10 CFR Part 54. For systems and structures that were “scoped in,” screening was performed to identify the passive components and structural members that support an intended function of the “in-scope” system or structure. These systems and structures are then subject to an AMR in accordance with 10 CFR 54.21(a). The results of the screening review were used to generate the P&IDs which show components that are subject to an AMR, as highlighted and marked by flags.

2.3.3.28.2 Staff Evaluation

The staff reviewed Sections 2.1 and 2.2 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the Catawba and McGuire nuclear service water system that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed Section 2.3 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the systems and structures of the NSW system that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3 of the LRA and the Catawba and McGuire UFSARs to identify any systems and structures of the NSW systems that may have been omitted from the scope of license renewal that meet the scoping criteria in 10 CFR 54.4. The staff verified that those portions of the NSW systems identified by the applicant as meeting the scoping requirements of 10 CFR 54.4 do in fact meet these requirements for both stations. The staff then focused its review on those portions of the NSW systems that were not identified by the applicant as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSARs to identify system functions that were not included in the LRA and verified that those functions met the scoping requirements of 10 CFR 54.4. Therefore, there is reasonable assurance that the applicant has adequately identified all portions of the Catawba and McGuire NSW systems that are within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the in-scope systems and structures that are subject to an AMR in accordance with 10 CFR 54.21(a). The applicant identified the systems and structures that are subject to an AMR for the NSW system and noted them in Table 3.3-36 for McGuire and Table 3.3-37 for Catawba. The staff performed its review by sampling the systems and structures that the applicant identified as within the scope of license renewal, but not subject to an AMR, to verify that these systems and structures perform their intended functions with moving parts or with a change in configuration or properties, or are subject to replacement based on qualified life or specified time period. All systems and structures reviewed by the staff met the above criteria for both Catawba and McGuire.

In Section 2.3.3.28 of the LRA, “Nuclear Service Water System,” the applicant listed 28 P&IDs for McGuire and 27 P&IDs for Catawba that were marked to indicate the license renewal evaluation boundary for the NSW system. The staff compared the flow diagrams to the information and descriptions in the UFSARs to ensure that the diagrams were representative of the NSW system for the respective plant. The applicant highlighted and flagged components on the P&IDs that are subject to an AMR. The staff sampled portions of the P&IDs that were not highlighted to ensure these components did not perform any of the intended functions associated with the scoping criteria of 10 CFR 54.4(a).

Paragraph 2.1.1.2.1 of the LRA states that some Duke Class G (non-safety related) components may be relied upon to remain functional during and following design basis events. Nuclear service water P&ID CN-1574-1.5, Note 16, indicates that buried Class G piping, from the auxiliary building to isolation valves 1RL054 and 1RL062, is seismically designed. The staff inferred that Class G piping may be relied upon to remain functional during and following design basis events. It was not discernable from the P&ID whether or not this piping is in scope. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.28-1, the applicant if the Duke Class G piping discussed above is within the scope of license renewal, and if it is not, to provide the basis for the exclusion. In its response dated April 15, 2002, the applicant indicated that the Class G piping discussed above is not within the scope of license renewal. The applicant further indicated that this piping is the normal NSW discharge and is not relied upon to remain functional during or following design basis events. The failure of the piping will not impact the system's safety-related function because the assured, safety-related nuclear service water discharge, which is within the scope of license renewal, is provided by a separate discharge line routed to the nuclear service water pond. The applicant also stated that the intent of Note 16 on CN-1574-1.5 is that, since the piping is underground, it is inherently missile-protected and seismically designed. The note was not meant to imply that the piping is required to have seismic design features. The staff concludes that this is acceptable because failure of the relevant Class G piping will not impair the function of the assured, safety-related nuclear service water discharge piping, which is within the scope of license renewal.

2.3.3.28.3 Conclusion

On the basis of its review of the information contained in Section 2.3.3.28 of the LRA, the supporting information in the Catawba and McGuire UFSARs, and the P&IDs, as described above, the staff did not identify any omissions in the scoping and screening of the Catawba and McGuire NSW system by the applicant. Therefore, the staff concludes that there is reasonable assurance that the applicant identified those portions of the Catawba and McGuire nuclear service water system that are within the scope of license renewal, and the systems and structures that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.29 Nuclear Service Water Pump Structure Ventilation System*

In Section 2.3.3.29 of the LRA titled, "Nuclear Service Water Pump Structure Ventilation System," the applicant identified portions of the nuclear service water pump structure ventilation (VZ) system and the components that are within the scope of license renewal and subject to an AMR. The applicant noted, in Section 2.3.3.29 of the LRA, that a system corresponding to the Catawba VZ system does not exist at McGuire. McGuire has no nuclear service water pump structure.

The applicant evaluated component supports for the VZ system ductwork in Table 3.5-3 of the LRA. The staff's scoping evaluations of component supports and electrical components are provided in Sections 2.4 and 2.5, respectively, of this report. Instrument line components in the VZ system were evaluated in Section 2.1 of the LRA.

2.3.3.29.1 Technical Information in the Application

The VZ system is an ESF. Two full-capacity supply fans in each pump compartment are served from separate trains of the emergency power system. Each essential fan is provided with a check damper on the fan discharge to prevent backflow through the standby fan. This ensures the integrity and availability of the ventilation system in the event of a loss of offsite power or any single active failure. A nonessential fan is provided in both pump compartments to supply ventilation air to the pool area below the pumps when maintenance or inspection is performed in this area. Modulating outside air and return air dampers are proportionally controlled to maintain space temperature.

In Section 2.3.3.29 of the LRA and Section 9.4.8 of the Catawba UFSAR, the applicant identified the following intended functions of the Catawba VZ system based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

Section 2.3.3.29 of the LRA—

- to maintain a suitable environmental temperature for the operation of equipment located in the nuclear service water pump structure

Section 9.4.8 of the Catawba UFSAR—

- to provide a suitable environment for the operation of equipment and personnel access for inspection, testing, and maintenance
- to maintain ambient temperature inside the nuclear service water pump structure within acceptable temperature limits

On the basis of the intended functions identified above for the Catawba VZ system, the portions of this system that were identified by the applicant as within the scope of license renewal include all VZ system safety-related components (electrical, mechanical, and instruments). The applicant described its methodology for identifying the mechanical components subject to an AMR in Section 2.1.2.1.2 of the LRA. On the basis of this methodology, the applicant identified the portions of the VZ system that are within the scope on the flow diagram listed in Section 2.3.3.29 of the LRA. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams and identified their intended functions. The applicant provided this list in Table 3.3-38 of the LRA.

The following component types are identified as within the scope of license renewal and subject to an AMR and are listed in Table 3.3-38 of the LRA—ductwork, pipe, tubing, and valve bodies. The applicant further noted in Table 3.3-38 of the LRA that the VZ system pressure boundary function is the only applicable intended function subject to an AMR.

2.3.3.29.2 Staff Evaluation

To verify that the applicant identified the components of the VZ system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.29 of the LRA to confirm the evaluation boundaries for the highlighted portions of the VZ system that are within the scope of license renewal. The staff reviewed Table 3.3-38 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed Sections 7.6.21 and 9.4.8 of the Catawba UFSAR to determine whether any portions of the VZ system that met the scoping criteria in 10 CFR 54.4(a) were not identified as within the scope of license renewal. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA, and if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VZ system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-38 of the LRA. The staff sampled the structures and components in Table 3.3-38 of the LRA to verify that the applicant did identify the structures and components subject to an AMR. The staff also sampled the structures and components that are within the scope of license renewal, but not subject to an AMR, to verify that these structure and components performed their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VZ system excluded from scope do not perform any intended functions, the staff requested additional information based on a review of the UFSAR and LRA description. The staff noted that Section 2.3.3.29 of the LRA provides a summary description of the system functions and references a flow diagram. The flow diagram highlights the evaluation boundaries, and Table 3.3-38 of the LRA tabulates the components within the scope and subject to an AMR for the VZ system. The corresponding drawings and the UFSARs, however, show additional components that were not listed in Table 3.3-38 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-9, specific information concerning the exclusion of the nuclear service water pump structure ventilation system fan housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant stated that cooling fans, without subcomponent exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant's basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan housings are passive long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-8, specific information concerning the exclusion of the VZ ventilation damper (or valve) housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that VZ system dampers are not included in the AMR results tables in the LRA. The applicant stated that ventilation dampers, without sub-component exceptions, are explicitly excluded from an

AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the damper housings are passive long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the nuclear service water pump structure ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub sections of Sections 2.2 and 2.3 of this SER.

Some components that are common to many systems, including the VZ system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

In Section 2.4.3 of this SER, the staff evaluated component supports for piping, cables, and equipment that supported the design and operation of the VZ system. In LRA Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls," the staff evaluated electrical and instrument components that support the operation of the VZ system.

The NRC staff reviewed the LRA, supporting information in the UFSAR, and the applicant's responses to the RAI. In addition, the staff sampled several components from the VZ system flow diagram, as identified in Section 2.3.3.29 of the LRA, to determine if the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

2.3.3.29.3 Conclusions

On the basis of its review, and with the open items identified in this SER section resolved, the staff has reasonable assurance that the applicant has adequately identified the VZ system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

*2.3.3.30 Nuclear Solid Waste Disposal System*

In LRA Section 2.3.3.30, "Nuclear Solid Waste Disposal System," the applicant described the components of the nuclear solid waste disposal system that are within the scope of license renewal and subject to an AMR. The system is described in Section 11.5 of the McGuire UFSAR and Section 11.4 of the Catawba UFSAR.

2.3.3.30.1 Technical Information in the Application

The nuclear solid waste disposal system contains and stores radioactive waste materials and prepares the waste for eventual shipment to a licensed offsite disposal facility. The applicant described the process for identifying the mechanical components that are within the scope of license renewal in LRA Section 2.1.1, "Scoping Methodology." As described in the scoping methodology, the applicant identified the portions of the nuclear solid waste disposal system that are within the scope of license renewal on the P&IDs that are listed in LRA Section 2.3.3.30. Consistent with the method described in LRA Section 2.1.2, "Screening Methodology," the applicant listed the nuclear solid waste disposal system mechanical components that are subject to an AMR in LRA Table 3.3-39. This table also lists the component functions. The applicant identified the following components as subject to an AMR—valve bodies, piping, screens (McGuire only), spent resin storage tanks (McGuire only), and tubing (McGuire only). All these components, except screens, have the intended component function of PB, which is defined by the applicant as maintaining pressure boundary, affecting containment isolation, or preventing interaction with safety-related equipment. The screens have the FI (filtration) function.

2.3.3.30.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.30 to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the nuclear solid waste disposal system that are within the scope of license renewal in accordance with 10 CFR 54.4(a) and that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information provided in LRA Section 2.3.3.30, the applicable P&IDs referenced therein, and the McGuire and Catawba UFSARs to determine if the applicant adequately identified the portions of the nuclear solid waste disposal system that are within the scope of license renewal. The staff verified that those portions of the nuclear solid waste disposal system that meet the scoping requirements of 10 CFR 54.4(a) were included within the scope of license renewal and were identified by the applicant in Section 2.3.3.30 of the LRA.

In LRA Section 2.3.3.30, the applicant listed applicable P&IDs for the nuclear solid waste disposal system. The detailed diagrams are highlighted to identify those portions of the system that are within the scope of license renewal. The staff compared the LRA diagrams to the system drawings and descriptions in the UFSARs to ensure that the diagrams were representative of the nuclear solid waste disposal system. To verify that the applicant included the applicable portions of the nuclear solid waste disposal system within the scope of license renewal, the staff focused its review on those portions of the nuclear solid waste disposal system that were not identified as within the scope of license renewal and verified that they did not meet the scoping criteria of 10 CFR 54.4(a). In addition, the staff reviewed the UFSARs for each facility to identify any additional system functions that were not identified in the LRA, and verified that the additional functions did not meet the scoping requirements of 10 CFR 54.4(a).

The staff reviewed McGuire UFSAR Table 3-4 for the solid waste disposal system and found the only components identified as safety Class 3 are the spent resin storage tank and some valves. The staff confirmed that the spent resin storage tanks and associated piping, screens, and valve bodies are included in LRA Table 3.3-39 as subject to an AMR. For Catawba, portions of the non-safety-related solid waste disposal system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions were classified as Duke Class F components. These components meet the scoping criterion of 10 CFR 54.4(a)(2). The staff confirmed that these components are highlighted in the P&IDs of the LRA. On the basis of the information in the P&IDs and UFSARs, the staff did not identify any omissions by the applicant in scoping of mechanical components according to 10 CFR 54.4(a).

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the solid waste disposal system that were identified as within the scope of license renewal. The applicant used the screening methodology described in LRA Section 2.1.2 to identify the SCs subject to an AMR. The staff evaluation of the scoping and screening methodology is documented in Section 2.1 of this SER. In the LRA, the applicant identified the portions of the solid waste disposal system that are within the scope of license renewal in the P&IDs and listed the mechanical components that are subject to an AMR and their intended component functions in LRA Table 3.3-39. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions by the applicant in screening SCs according to 10 CFR 54.21(a)(1).

2.3.3.30.3 Conclusions

On the basis of its review of the information contained in LRA Section 2.3.3.30, the supporting information in the P&IDs, and the McGuire and Catawba UFSARs, as described above, the staff did not identify any omissions by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant adequately identified those portions of the solid waste disposal system that are within the scope of license renewal and the associated SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.31 Reactor Coolant Pump Motor Oil Collection Subsystem*

LRA Section 2.3.3.31, “Reactor Coolant Pump Motor Oil Collection Subsystem,” identified that structures, systems, and components (SSCs) relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with 10 CFR 50.48, the FP rule, are within the scope of license renewal. In LRA Section 2.3.3.31, the applicant identified the FP flow diagrams that had been marked to show the license renewal evaluation boundary for the RCP motor oil collection subsystem for McGuire and Catawba. The applicant also identified the SSCs for the RCP motor oil collection subsystem that are subject to an AMR for McGuire and Catawba in LRA Table 3.3-40. In a letter to the applicant dated January 28, 2002, the NRC requested additional information regarding the RCP motor oil collection subsystem. In a letter to the NRC dated April 15, 2002, the applicant provided additional information in response to the staff’s RAIs.

2.3.3.31.1 Technical Information in the Application

In accordance with 10 CFR 54.4(a)(3), SSCs that are relied on in safety analyses or plant evaluation to demonstrate compliance with 10 CFR 50.48 are within the scope of license renewal. The RCP motor oil collection subsystem is relied upon to meet the requirements of 10 CFR Part 50, Appendix R, Section III.O, “Oil Collection System for Reactor Coolant Pump.”

In accordance with 10 CFR 50.48, the applicant is required to implement and maintain an FP program. As stated in LRA Section 2.1.1.3.1, the licensing basis with regard to fire protection differs at McGuire and Catawba. McGuire and Catawba are both licensed to 10 CFR 50.48(b) as specifically stated in the plants’ SERs and the facility operating licenses. License conditions 2.C.(3) and 2.C.(7) apply for McGuire and license conditions 2.C(8) and 2.C.(6) apply for Catawba. The NRC SER, NUREG-0422, provides the staff evaluation which documents the McGuire compliance with Appendix A of BTP APCSB 9.5-1, "FP for Nuclear Power Plants." The NRC SER, NUREG-0954, provides the staff evaluation which documents the Catawba compliance with Appendix A to BTP APCSB 9.5-1.

McGuire and Catawba are both committed to provide an RCP oil collection system in accordance with the requirements of Appendix R. The RCP lube oil is a significant fire hazard and the underlying purpose of the lube oil collection system is to ensure that leaking oil will not lead to a fire that could damage safety-related equipment during normal conditions or design basis conditions. Appendix R, Section III.O, states the following—

> Such collection systems shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems. Leakage shall be collected and drained to a vented closed container that can hold the entire lube oil system inventory. A flame arrester is required in the vent if the flash point characteristics of the oil present the hazard of fire flashback. Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines, and lube oil reservoirs where such features exist on the reactor coolant pumps. The drain line shall be large enough to accommodate the largest potential oil leak.

As described in the LRA, the applicant listed the mechanical components subject to an AMR for this system and their intended functions in LRA Table 3.3-40. On the basis of the methodology described above, the applicant identified that the highlighted components, shown on the flow diagrams listed in LRA Section 2.3.3.31, are included within the scope of license renewal. These component types identified in this Table 3.3-40 include—flexible hoses, level gauges, tanks, pump casings, lower oil catcher, lower oil pot (McGuire only), oil lift enclosure, upper oil cooler enclosures, pipe, and valve bodies. The applicant further identified that the only intended function of these component types is to maintain the integrity of the RCP motor oil collection subsystem pressure boundary.

2.3.3.31.2 Staff Evaluation

The Commission’s regulations in 10 CFR 54.21(a)(1) state that for those SSCs that are within the scope of Part 54, as delineated in 10 CFR 54.4, the applicant must identify and list those SCs that are subject to an AMR. The staff reviewed Section 2.3.3.31 of the LRA, as supplemented by a letter to the NRC dated January 28, 2002, to determine whether there was reasonable assurance that the applicant has appropriately identified the SSCs that serve RCP oil collection system intended functions that are within the scope of license renewal in accordance with 10 CFR 54.4, and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The applicant is required to meet the requirements of Appendix R, Section III.O to 10 CFR Part 50. Therefore, SSCs relied on in safety analyses or plant evaluations to demonstrate compliance with 10 CFR 50.48 are included in scope of license renewal. Section 2.3.3.31 of the LRA states that each RCP for McGuire and Catawba is equipped with an oil collection system that meets the requirements of Appendix R, Section III.O.

The staff reviewed portions of the flow diagrams listed in LRA Section 2.3.3.31 for McGuire and Catawba to identify any additional RCP oil collection subsystem functions that met the scoping requirements of 10 CFR 54.4 but that were not identified as intended functions in the LRA. The staff also reviewed the SERs (NUREG- 0422 for McGuire and NUREG -0954 for Catawba) which summarize the FP programs.

The staff then compared the RCP oil collection subsystem components identified in the flow diagrams to verify that the required components were highlighted as being within the evaluation boundaries on the flow diagram, and were not excluded from the scope of license renewal. As part of the evaluation, the staff also sampled portions of the same flow diagrams for the RCP oil collection subsystem to determine if there were any additional portions of the system piping or components located outside of the evaluation boundary that should have been identified as within the scope of license renewal.

The staff was concerned that the applicant had excluded a portion of the RCP oil collection subsystem piping from within the scope of license renewal. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.31-1, the applicant to discuss why the portion of the RCP motor oil collection subsystem within the dashed lines on flow diagrams CN-1553-1.3 and MCFD-1553-04.00, is excluded from the scope of license renewal, and to verify that this portion of the system is not required for compliance with Appendix R, Section III.O. In its response dated April 15, 2002, the applicant stated that the portion of the RCP motor oil collection subsystem within the dashed lines on flow diagrams CN-1553-1.3 and MCFD-1553-04.00 is not required for compliance with Appendix R, Section III.O. This excluded portion of the system is a portable skid that is connected to the system only when needed to refill the motor with oil. Because the portable skid is used for maintenance purposes and is not relied upon to mitigate a fire, the staff was satisfied with the applicant's response.

After determining which components were within the scope of license renewal, the staff reviewed the components the applicant identified as being subject to an AMR. The staff reviewed selected components that the applicant identified as within the scope of license renewal to verify that the applicant determined those SCs that performed their intended functions without moving parts or without a change in configuration or properties, and that are not subject to replacement based on qualified life or specified time period, were subject to an AMR.

The staff also reviewed mechanical components from the flow diagrams identified in LRA Section 2.3.3.31 and compared them to the list of components and corresponding intended function(s) in Table 3.3-40 of the LRA. On the basis of this review, the staff did not identify any omissions in the SCs identified by the applicant as being subject to an AMR.

2.3.3.31.3 Conclusions

On the basis of the review described above, the staff finds that there is reasonable assurance that the applicant has adequately identified those portions of the RCP motor oil collection subsystem that are included within the scope of license renewal, and the associated SSCs that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.3.3.32 Reactor Coolant System (Non-Class 1 Components)*

In LRA Section 2.3.3.32, “Reactor Coolant System (Non-Class 1 Components),” the applicant described the non-Class 1 components of the reactor coolant system that are within the scope of license renewal and subject to an AMR.

2.3.3.32.1 Technical Information in the Application

The non-Class 1 portions of the reactor coolant system (excluding the reactor coolant pump motor oil collection subsystem) are relied upon to provide and maintain containment isolation and closure and maintain system pressure boundary integrity. An additional intended function identified in Table 3.3-41 (for orifices only) is throttling flow. The reactor vessel leak off line is included within this set of components and is relied upon only in the event the reactor vessel flange inner seal leaks.

The component types, component functions, materials of construction, environments, aging effects, and aging management programs/activities for the McGuire and Catawba reactor coolant system (non-Class 1 components) are listed in Table 3.3-41 of the LRA. The following component types are listed—orifices, pipe, tubing, and valve bodies.

2.3.3.32.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the reactor coolant system (non-Class 1 components), and associated pressure boundary components and supporting structures within the scope of license renewal and subject to an AMR, have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively. The staff reviewed the relevant portions of the UFSARs for McGuire and Catawba for the reactor coolant system (non-Class 1 components) and associated pressure boundary components, and compared the information in the UFSAR with the information in the LRA to identify those portions that the LRA did not identify as within the scope of license renewal and subject to an AMR. The staff then focused on those portions of the reactor coolant system (non-Class 1 components) that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. For those structures and components that have applicable intended functions, the staff sought to verify that they either perform these functions with moving parts, or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the UFSAR for any function(s) delineated under 10 CFR 54.4(a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained consistent with the CLB for the extended period of operation.

The staff did not identify any omissions.

2.3.3.32.3 Conclusions

On the basis of its review of the information presented in Section 2.3.3.32 of the LRA, and the supporting information in the McGuire and Catawba UFSARs, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the reactor coolant system (non-Class 1 components) and the associated supporting structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

*2.3.3.33 Recirculated Cooling Water System*

In LRA Section 2.3.3.33, “Recirculated Cooling Water System,” the applicant described the components of the Catawba recirculated cooling water system that are within the scope of license renewal and subject to an AMR.  Although the LRA notes that no portion of the McGuire recirculated cooling water system is within the scope of license renewal, Supplement 1 to the LRA, provided by the applicant in a letter dated June 25, 2002, stated that portions of this system had been included within the scope of license renewal for McGuire.  This system is further described in Section 9.2.1 of the McGuire UFSAR.

The staff reviewed the LRA for Catawba, and LRA Supplement 1 and UFSAR for McGuire, to determine whether the applicant has adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.33.1 Technical Information in the Application

The Catawba and McGuire Nuclear Station recirculated cooling water system is a closed cooling system that delivers clean, rust-inhibiting, cooling water of a regulated temperature to various components in the turbine building, auxiliary building, and service building.

The applicant described the process for identifying the SSCs within the scope of license renewal in LRA Section 2.1.1, “Scoping Methodology,” and its process for identifying the SSCs subject to an AMR in LRA Section 2.1.2, “Screening Methodology.”  Using the methodology described in LRA Section 2.1.1, the applicant listed the systems and structures that are within the scope of license renewal in LRA Tables 2.2-1 and 2.2-2 for McGuire and Catawba, respectively.  The Catawba recirculated cooling water system is listed on page 2.2-7 in Table 2.2-2 of the LRA. The McGuire recirculated cooling water system was added to the scope of licensed renewal as noted on page 2 of LRA Supplement 1.

The LRA notes that the only portions of the recirculated cooling water system subject to an AMR are the Duke Class F portions of the recirculated cooling water system that are in scope at Catawba.  Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the Catawba mechanical components that are subject to an AMR in Table 3.3-42, “Aging Management Results - Recirculated Cooling Water System.”  This table also lists the intended function of each component and the materials of construction. The applicant identified the following components of the recirculated cooling water system that are subject to an AMR—pipe and valve bodies. The applicant identified maintaining pressure boundary integrity as the only intended function of the SCs subject to an AMR.

At the time of the preparation of the LRA, a plant modification was proposed to downgrade all piping within the McGuire recirculated cooling water system to a non-safety class of piping. At the time the LRA was submitted, none of this piping was included within the scope of license renewal. Subsequent to the submittal of the LRA, the proposed modification was implemented, however, some portions of the recirculated cooling water system were not downgraded, remained as Class F piping, and thus should have been identified as within the scope of license renewal. Using the methodology described in Section 2.1.2 of the LRA, the applicant listed the McGuire mechanical components that are subject to an AMR in Table 1 of LRA Supplement 1, "Recirculated Cooling Water System (KR) Component Screening and Aging Management Review Results (McGuire Nuclear Station)." This table also lists the intended function of each component and the materials of construction. The applicant identified pipe as the only component of the McGuire recirculated cooling water system that is subject to an AMR. The applicant identified maintaining pressure boundary integrity as the only intended function of the SCs subject to an AMR.

2.3.3.33.2 Staff Evaluation

The staff reviewed Section 2.3.3.33 of the LRA, and Section 3 of LRA Supplement 1, to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the recirculated cooling water system that are within the scope of license renewal in accordance with 10 CFR 54.4, and to verify that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 2.3.3.33 of the LRA, Section 3 of LRA Supplement 1, and the applicable piping and instrument drawings referenced therein, and the McGuire UFSAR, to determine if the applicant adequately identified the portions of the recirculated cooling water system that are within the scope of license renewal.

The Catawba recirculated cooling water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). The applicant included all components within the seismically designed piping boundaries of this system within the scope of license renewal per 10 CFR 54.4(a)(2). The staff verified that those portions of the recirculated cooling water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were so identified by the applicant in Section 2.3.3.33 of the LRA. To verify that the applicant did include the applicable portions of the recirculated cooling water system as within the scope of license renewal, the staff focused its review on those portions of the recirculated cooling water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4. The staff did not identify any omissions in the applicant's scoping review.

As noted in NRC Inspection Report 50-369/02-05, 50-370/02-05, 50-413/02-05 and 50-414/02-05 for the scoping and screening inspection of McGuire and Catawba Nuclear

Stations, the inspectors observed that the applicant had relied on a proposed modification of the recirculated cooling water system at McGuire to downgrade the piping classification that was not yet implemented when the LRA was submitted. Upon completion, the modification method had changed and a portion of the piping system had remained Class F and, therefore, should have been in license renewal scope. This was the only case identified by the inspectors where the applicant had relied on a proposed modification. As discussed above, the applicant added the McGuire recirculated cooling water system to the license renewal scope in LRA Supplement 1. The McGuire recirculated cooling water system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are designated Duke Class F. The applicant included all components within the Duke Class F designated piping boundaries of this system within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff verified that those portions of the recirculated cooling water system that meet the scoping requirements of 10 CFR 54.4 were included within the scope of license renewal and were so identified by the applicant in Section 3 of LRA Supplement 1. To verify that the applicant did include the applicable portions of the recirculated cooling water system as within the scope of license renewal, the staff focused its review on those portions of the recirculated cooling water system that were not identified as within the scope of license renewal to verify that they did not meet the scoping criteria of 10 CFR 54.4. In addition, the staff reviewed the McGuire UFSAR to identify any additional system intended functions that were not identified in LRA Supplement 1, and verified that these additional intended functions did not meet the scoping requirements of 10 CFR 54.4. The staff did not identify any omissions in the applicant's scoping review other than those that were documented in the NRC inspection report.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR in those portions of the recirculated cooling water system that are identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the recirculated cooling water system in Table 3.3-42 of the LRA and Table 1 of LRA Supplement 1 for Catawba and McGuire, respectively, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER.

The applicant identified the portions of the Catawba recirculated cooling water system that are within the scope of license renewal by a highlighted Catawba drawing referenced in LRA Section 2.3.3.33. In addition, the applicant lists the pipe and valve body mechanical component commodity groups that are subject to an AMR and their intended functions in Table 3.3-42 of the LRA.

The applicant identified the portions of the McGuire recirculated cooling water system that are within the scope of license renewal by highlighted McGuire drawing MCFD-1600-01-01 referenced in LRA Supplement 1. In addition, the applicant lists pipe as a mechanical component commodity group subject to an AMR and its intended function in Table 1 of LRA Supplement 1.

The piping and instrumentation drawings were highlighted by the applicant to identify those portions of the recirculated cooling water system that meet at least one of the scoping criteria of 10 CFR 54.4. The staff performed its review by sampling the SCs that the applicant determines to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement on the basis of qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions.

2.3.3.33.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.33 of the LRA, Section 3 of LRA Supplement 1, the LRA, LRA Supplement 1 drawings, and the McGuire and Catawba UFSARs, the staff did not identify any omissions in the scoping of the recirculated cooling water system by the applicant beyond those identified in NRC Inspection Reports 50-369/02-05, 50-370/02-05, 50-413/02-05 and 50-414/02-05 as discussed above. The staff concludes that there is reasonable assurance that the applicant identified those portions of the recirculated cooling water system that are within the scope of license renewal, and the SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.34 Spent Fuel Cooling System*

In Section 2.3.3.34 “Spent Fuel Cooling System,” of the LRA, the applicant described the components of the spent fuel cooling system that are within the scope of license renewal and subject to an AMR. Section 9.1.3 of the Catawba and McGuire UFSARs provides additional information concerning their respective spent fuel cooling systems.

2.3.3.34.1 Technical Information in the Application

For the purposes of license renewal, the Catawba and McGuire spent fuel cooling systems are essentially the same and perform the same functions. The Catawba spent fuel cooling system, in conjunction with the component cooling water system and nuclear service water system, is designed to remove heat from the spent fuel pool and maintain purity and optical clarity of the pool water during fuel handling operations. The purification loop provides an alternate means for removing impurities from the refueling cavity/transfer canal water during refueling, and from the refueling water storage tank water following refueling.

The McGuire spent fuel cooling system removes heat from the spent fuel pool and maintains the purity and optical clarity of the pool water for fuel handling operations. The purification loop provides an alternate means for removing impurities from the refueling canal/transfer canal water during refueling, and from the refueling water storage tank water following refueling. The fuel pool water also serves as a source of makeup water to the reactor coolant system during an event that is mitigated by the standby shutdown system.

Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and their materials of construction for the spent fuel cooling system are listed in Table 3.3-43 of the LRA. In LRA Table 3.3-43, the applicant lists the following 10 component commodity groups as subject to an AMR—heat exchangers (channel head, shell, tube sheet, and tubes), orifices, pipe, pump casings, spacers, tubing, and valve bodies. LRA Table 3.3-43 also lists spacers as a component commodity group that is subject to an AMR only for the McGuire spent fuel cooling system. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. The heat exchangers (tubes) also provide a heat transfer function (to maintain system and/or component operating temperature).

2.3.3.34.2 Staff Evaluation

The staff reviewed Section 2.3.3.34 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the spent fuel cooling system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.34 of the LRA, and the Catawba and McGuire UFSARs, to determine if the applicant adequately identified the SSCs of the spent fuel cooling system that are in the scope of license renewal. The staff verified that those portions of the spent fuel cooling system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal and are identified by the applicant in Section 2.3.3.34 of the LRA. The staff then focused its review on those portions of the spent fuel cooling system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that no additional functions met the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the spent fuel cooling system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the spent fuel cooling system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the spent fuel cooling systems in Table 3.3-43 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines to be within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, and were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the spent fuel cooling system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which it believes perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSARs to ensure the diagrams were representative of the spent fuel cooling system. The staff sampled components in the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.3.34.3 Conclusions

On the basis of its review of the information in Section 2.3.3.34 of the LRA, and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the spent fuel cooling system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.35 Standby Shutdown Diesel*

In LRA Section 2.3.3.35, "Standby Shutdown Diesel," the applicant described the components of the standby shutdown diesel that are within the scope of the license renewal and subject to an AMR. The staff reviewed the LRA to determine if the applicant adequately demonstrated that the requirements of 10 CFR Part 54 have been met.

2.3.3.35.1 Technical Information in the Application

The standby shutdown diesel provides an alternate and independent means of achieving and maintaining a hot standby condition for one or both units following a postulated fire event. The standby shutdown diesel provides power to the standby shutdown facility required components, instrumentation, and controls for a period of up to 72 hours.

The applicant described the process for identifying the SSCs within the scope of license renewal in Section 2.1.1 of the LRA. Using that scoping methodology, the applicant determined that the standby shutdown diesel was within the scope of license renewal and listed it on page 2.2-3 in Table 2.2-1 for McGuire, and on page 2.2-8 in Table 2.2-2 for Catawba. The LRA included system drawings that were highlighted to indicate the license renewal evaluation boundary.

The applicant described the process for identifying the SCs subject to an AMR in Section 2.1.2 of the LRA. Using that screening methodology, the applicant listed the mechanical components of the standby shutdown diesel subsystems that are subject to an AMR in LRA Table 3.3-44 for both McGuire and Catawba. In LRA Table 3.3-44, the applicant grouped the components for the standby shutdown diesel in four subsystems—the cooling water and jacket water heating subsystem, the exhaust subsystem, the fuel oil subsystem, and the lubrication oil subsystem. For the cooling water and jacket water heating subsystem, the applicant identified the following component types as subject to an AMR—(1) filter, cooling water mounting head, (2) heat exchanger, engine radiator tubes, channel head, leak off connector, and cap flange, (3) tubing, (4) valves bodies, jacket water heater, and (5) water heater, jacket shell. For the exhaust subsystem, the applicant identified the following component types as subject to an AMR—(1) bellows, (2) pipes, and (3) silencer. For the fuel oil subsystem, the applicant identified the following component types as subject to an AMR—(1) filter, duplex (mounting head), (2) flame arrestor (McGuire only), (3) level glasses, (4) pipes for fuel oil, day tank vents, day tank drain (McGuire only), storage tank vents, and storage tank suctions, (5) pump casings, fuel oil transfer and engine fuel oil, (6) tanks, fuel oil storage, fuel oil storage manway, and fuel oil day, (7) tubing, fuel oil day tank, and (8) valve bodies. For the lubrication oil subsystem, the applicant identified the filters for lube oil bypass and the lube oil mounting head as subject to an AMR. The applicant stated that the intended functions of the components are to maintain mechanical pressure boundary integrity to ensure that sufficient flow and pressure are delivered, to effect containment isolation for fission product retention, to prevent physical interaction with safety-related equipment, and also provide heat transfer so that system and/or component operating temperatures are maintained.

#### 2.3.3.35.2 Staff Evaluation

The staff reviewed Section 2.3.3.35 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the standby shutdown diesel that are within the scope of license renewal in accordance with 10 CFR 54.4, and that the applicant appropriately identified the mechanical components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and applicable drawings submitted by the applicant in Section 2.3.3.35 of the LRA to verify that the applicant adequately identified the portions of the standby shutdown diesel that meet the scoping requirements of 10 CFR 54.4, and that these portions were included within the scope of license renewal in Section 2.3.3.35 of the LRA. The staff focused its review on those portions of the standby shutdown diesel that were not identified as within the scope of license renewal to verify that they did not meet the scoping requirements of 10 CFR 54.4.

The staff reviewed Table 3.3-44 of the LRA, which lists the mechanical components subject to an AMR for the standby shutdown diesel for McGuire and Catawba. The staff verified that the applicant properly identified the mechanical components that were subject to an AMR from among those portions of the standby shutdown diesel that were identified as within the scope of license renewal. The staff sampled the components that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no component that performs its intended functions without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from LRA Table 3.3-44.

During its review of Section 2.3.3.35, the staff determined that additional information was needed to complete its review. The standby shutdown diesel radiator is listed in LRA Table 3.3-44 as a component subject to an AMR, which implies that the radiator is within the scope of license renewal. McGuire drawing MC-1614-4 shows that the standby shutdown diesel engine radiator is air cooled by an engine-driven fan. The standby shutdown diesel and its supporting subsystems are relied on to perform a function that demonstrates compliance with the Commission's regulation for station blackout. Therefore, they meet the scoping requirement of 10 CFR 54.4(a)(3). As a subsystem of the standby shutdown diesel, the fan identified on MC-1614-4 should be within the scope of the license renewal and listed in Table 3.3-44 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.35-1, that the applicant provide the basis for not listing the engine-driven fan in Table 3.3-44. The staff also requested that the applicant confirm the existence of an air cooling system for the standby shutdown diesel engine radiator at Catawba and address its inclusion in the scope of license renewal. It should be noted here that, in RAI 2.3.3.35-1, the staff mistakenly referred to Table 3.3-34 instead of referring to Table 3.3-44. In its response dated April 15, 2002, the applicant stated that the engine-driven fan was not excluded from the scope of license renewal and that it was within the license renewal boundary highlighted on MC-1614-4. The applicant also stated that the air cooling system for the standby shutdown diesel radiator at McGuire was subject to an AMR and was listed in Table 3.3-46, "Turbine Building Ventilation System," rather than in Table 3.3-44, because the turbine building ventilation system performs the HVAC for the standby shutdown facility. In response to the staff's question regarding the existence of a cooling system for the standby shutdown diesel radiator at Catawba, the applicant responded that the McGuire and Catawba shutdown diesels are of the same design. The applicant indicated that the AMR results for the Catawba standby shutdown diesel radiator were listed in Table 3.3-33 of the LRA, “Miscellaneous Structures Ventilation System,” rather than in LRA Table 3.3-44, because the miscellaneous structures ventilation system performs the HVAC function for the standby shutdown facility. The applicant also stated that the only long-lived passive component associated with the standby shutdown diesel engine radiator is the plenum (the AMR results of which the staff verified are provided in Tables 3.3-33 and 3.3-46 of the LRA). Other components, such as the fans, are within the scope of license renewal, but are not subject to an AMR. Cooling fans, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21(a)(1)(i). The staff finds the applicant’s response acceptable because the air cooling systems for the McGuire and Catawba standby shutdown diesel radiator were identified by the applicant as within the scope of license renewal.

Table 3.3-44 of the LRA lists the standby shutdown diesel components subject to an AMR. The list includes the pump casing for the fuel oil transfer pump. McGuire drawing MCFD-1560-01.00 and Catawba drawing CN-1560-1.0 do not show a pump by that name. By letter dated January 28, 2002, the staff asked, in RAI 2.3.3.35-2, the applicant if the fuel oil transfer pump in Table 3.3.44 is the same component as the fuel oil day tank pump on drawings MCFD-1560-01.00 and CN-1560-1.0. In its response dated April 15, 2002, the applicant confirmed that the fuel oil transfer pump listed in Table 3.3.44 refers to the component listed as standby shutdown fuel oil day tank pump at coordinates F2 on drawings MCFD-1560-01.00 and CN-1560-1.0. The applicant’s clarification of this information assisted the staff in completing its review.

On drawings MCFD-1560-01.00, MCFD-1560-02-00, CN-1560-1.0, and CN-1560-2.0, the flexible hose connections on the fuel oil subsystem on either side of the engine are shown to be within the scope of license renewal. Although these components appear to have a pressure boundary intended function, they are not listed in LRA Table 3.3-44 as subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.35-3, that the applicant provide the basis for excluding these flexible hose connections from the lists of components subject to an AMR. In its response dated April 15, 2002, the applicant stated that these flexible hose connections are replaced during periodic maintenance on the diesel engine and, in accordance with 10 CFR 54.21(a)(1)(ii), are not subject to an AMR. The applicant specified that drawings MCFD-1560-02-00 and CN-1560-2.0 show no fuel oil component. Because the applicant did not provide information about the replacement of these flexible connectors (whether they are replaced on condition based on specific performance parameters or based on a qualified life), the staff is unable to evaluate the acceptability of this response. This issue was characterized as SER open item 2.3.3.35.2-1. In its response to this open item, dated October 28, 2002, the applicant stated that the flexible hoses in the standby shutdown diesel generator fuel oil subsystem are inspected for cracking and signs of wear on an 18-month frequency and replaced based on condition. The staff finds this to be an acceptable basis for excluding these hoses from an AMR. Therefore, open item 2.3.3.35.2-1 is closed.

Drawings MCFD-1560-01.00, MCFD-1560-02-00, CN-1560-1.0, and CN-1560-2.0 depict the portions of the standby shutdown diesel subsystems that are within the scope of license renewal. It is not apparent from these drawings how the standby shutdown diesel lube oil subsystem accomplishes its function of lubricating the diesel engine, and the UFSARs for McGuire and Catawba do not provide any written description of these subsystems. As a result, the staff was not able to determine, during its review of the LRA, if all the passive and long-lived subsystems components that are within the scope of license renewal, were included in LRA Table 3.3-44 to indicate that they were subject to an AMR. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.35-4, that the applicant provide a system description and an explanation of how this subsystem performs its intended function. In its response dated April 15, 2002, the applicant stated that the standby shutdown diesel engine is a small, 16-cylinder diesel engine, and that the entire lubrication system is contained inside the diesel engine. The only external components are the lube oil filters and they are listed in LRA Table 3.3-44. The components internal to the engine, such as the pump and the lube oil cooler, are considered part of the diesel engine and are excluded from an AMR by 10 CFR 54.21(a)(1)(i). The applicant further specified that only the components associated with the filter (mounting head and bypass) are listed in Table 3.3-44 of the LRA. The filter itself is replaced during periodic maintenance and is not subject to an AMR. The staff finds the applicant's response acceptable because, even though portions of the pump and the lube oil cooler may be passive, the pump and the lube oil cooler are parts of the standby shutdown diesel generator and, therefore, are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i). The staff's evaluation of the applicant's treatment of filters is documented in Section 2.1.3.2.1 of this SER.

LRA Table 3.3-44 lists the McGuire and Catawba components that are subject to an AMR for the cooling water and jacket water heating subsystem for the standby shutdown diesel. The table does not list piping or pump casings. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.35-5, that the applicant provide the basis for excluding the piping and pump casings from LRA Table 3.3-44 as subject to an AMR. In its response dated April 15, 2002, the applicant stated that the component called "tubing," listed in LRA Table 3.3-44 for the cooling water and jacket water heating sub system, reflects the terminology used by the vendor for piping. The applicant added that a visual inspection of the diesel confirmed that this tubing, as it is referred to in the vendor manuals, is actually carbon steel pipe. As a result, the applicant supplemented LRA Table 3.3-44 to read as follows—

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effects | Aging Management Programs and Activity |
|---|---|---|---|---|---|
| Pipe | PB | CS | Treated Water | Cracking (Note 3) | Chemistry Control Program |
| | | | | Loss of Material | Chemistry Control Program |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |

In its response to RAI 2.3.3.35-5, the applicant stated that the pump casing for the diesel generator cooling water and jacket water heating subsystem had been inadvertently omitted from Table 3.3-44 of the LRA and provided the following supplemental information—

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effects | Aging Management Programs and Activity |
|---|---|---|---|---|---|
| Pump Casing (cooling water) | PB | CS | Treated Water | Cracking (Note 3) | Chemistry Control Program |
| | | | | Loss of Material | Chemistry Control Program |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |

Since the applicant provided the AMR results for the pump casing and clarified that tubing was specified for the piping in question, the staff finds its response acceptable. The supplemental information for LRA Table 3.3-44 to reflect the vendor's characterization of the tubing as piping is a further clarification that is helpful because it accurately reflects the vendor's documentation. The staff's evaluation of the AMR results for the carbon steel pipe and pump casings is documented in Section 3.3.35.2 of this SER.

2.3.3.35.3 Conclusions

The staff reviewed the information contained in Section 2.3.3.35 of the LRA, the applicable LRA drawings, and applicant responses to RAIs and SER open items. With the resolution of open item 2.3.3.35.2-1, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the standby shutdown diesel that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.3.36 Turbine Building Sump Pump System*

In LRA Section 2.3.3.36, "Turbine Building Sump Pump System," the applicant described the components of the Catawba turbine building sump pump system that are within the scope of license renewal and subject to an AMR. McGuire has no Class F components in the turbine building sump pump system, therefore, no portion of the McGuire turbine building sump pump system is within the scope of license renewal. As a result, the following staff evaluation only applies to Catawba. The Catawba turbine building sump pump system is not described in the UFSAR.

2.3.3.36.1 Technical Information in the Application

The turbine building sump pump system serves as a collection point for the contents of liquid radwaste system sumps when the sumps contain less than predetermined levels of radiation, as sensed by radiation monitors in the discharge lines. The turbine building sump pump system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2). Using the methodology described in Section 2.1.2, "Screening Methodology," of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR and their intended functions and materials of construction for the Catawba turbine building sump pump system are listed in LRA Table 3.3-45. In LRA Table 3.3-45, the applicant lists the following mechanical component as subject to an AMR—pipe. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

2.3.3.36.2 Staff Evaluation

The staff reviewed Section 2.3.3.36 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the turbine building sump pump system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.3.36 of the LRA to determine if the applicant adequately identified the SSCs of the turbine building sump pump system that are in the scope of license renewal. The staff verified that those portions of the turbine building sump pump system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.3.36 of the LRA. The staff then focused its review on those portions of the turbine building sump pump system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the turbine building sump pump system that should be included within the scope of license renewal in accordance with 10 CFR Part 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the turbine building sump pump system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the turbine building sump pump systems in Table 3.3-45 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the turbine building sump pump system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4.

2.3.3.36.3 Conclusions

On the basis of its review of the information contained in Section 2.3.3.36 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the turbine building sump pump system that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.3.37 Turbine Building Ventilation System*

In LRA Section 2.3.3.37, "Turbine Building Ventilation System," the applicant identified components of the turbine building ventilation system that are within the scope of license renewal and subject to an AMR. This specific system is only applicable to McGuire. The McGuire turbine building ventilation (VO) system includes the standby shutdown facility (SSF) heating, ventilation, and air-conditioning subsystems. The standby shutdown facility heating, ventilation, and air-conditioning portion of the VO system provide the environmental control requirements for the standby shutdown facility.

The applicant evaluated component supports for the VO system ductwork within Table 3.5-3 of the LRA. The applicant evaluated electrical components that support the operation of the system in Section 2.1.2.3 of the LRA. The staff's scoping evaluation of structures and component supports is provided in Section 2.4 of this SER. The staff's evaluation of electrical components and instrumentation and controls in the VO system is documented in Section 2.5 of this SER.

2.3.3.37.1 Technical Information in the Application

The SSF heating ventilation, and air-conditioning subsystems are part of the McGuire VO system. The SSF control room is air-conditioned while the standby shutdown facility electrical equipment room and SSF diesel room are provided with ventilation, fans, and electric heaters.

In Section 2.3.3.37 of the LRA, the applicant identified the following McGuire VO system intended function based on 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2)—

Section 2.3.3.37 of the LRA—

- to provide the environmental conditioning requirements for the standby shutdown facility

Section 9.4.4 of the McGuire UFSAR—

- to provide a suitable environment for the operation of equipment and personnel access as required for inspection, testing, and maintenance
- to maintain the ambient temperature limit within the turbine building
- to provide air-conditioning for the SSF control room and battery rooms
- to provide ventilation and heat for the SSF electrical equipment room and SSF diesel rooms

On the basis of the intended functions identified above for the McGuire SSF heating ventilation and air-conditioning subsystems, the portions of this system that were identified by the applicant as within the scope of license renewal included components highlighted on the referenced flow diagram in Section 2.3.3.37 of the LRA. The applicant described their methodology for identifying the mechanical components subject to an AMR in Section 2.1 of the LRA. On the basis of this methodology, the applicant identified the portions of the SSF heating ventilation and air-conditioning subsystems that are within the scope of license renewal. Using the methodology described in Section 2.2.1 of the LRA, the applicant compiled a list of the mechanical components and component types subject to an AMR that are within the evaluation boundaries highlighted on the flow diagrams, and identified their intended functions. The applicant provided this list in Table 3.3-46 of the LRA.

The following component types are identified as within the scope of license renewal and subject to an AMR within Table 3.3-46 of the LRA—air handling unit, ductwork, flexible connectors, and plenum section. The applicant indicated in Table 3.3-46 of the LRA for the McGuire SSF heating, ventilation, and air-conditioning portion of the VO system that the pressure boundary function is the only applicable intended function.

2.3.3.37.2 Staff Evaluation

To verify that the applicant identified the components of the VO system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), the staff reviewed the flow diagram listed in Section 2.3.3.37 showing the evaluation boundaries for the highlighted portion of the VO system that are within the scope of license renewal. The staff also reviewed Table 3.3-46 of the LRA, which lists the mechanical components and the applicable intended functions that are subject to an AMR. The staff also reviewed Section 9.4.4 of the McGuire UFSAR to determine if there were any portions of the VO system that met the scoping criteria in 10 CFR 54.4(a) that were not identified as within the scope of license renewal. The staff also reviewed the McGuire and Catawba UFSARs to determine if any safety-related system functions were not identified as intended functions in the LRA, and to determine if any structures or components that have intended functions were omitted from the scope of structures or components that require an AMR. The staff compared the functions described in the UFSARs to those identified in the LRA.

The applicant identified the structures and components subject to an AMR for the VO system using the screening methodology described in Section 2.1 of the LRA and listed them in Table 3.3-46 of the LRA. The staff sampled the structures and components from Table 3.3-46 of the LRA to verify that the applicant did identify the structures and components subject to an AMR. The staff also sampled the structures and components that were within the scope of license renewal, but not subject to an AMR, to verify that the structures and components perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period.

To ensure that those portions of the VO system excluded from scope do not perform any intended functions, the staff requested additional information based on a review of the McGuire UFSAR and LRA descriptions. The staff noted that Section 2.3.3.37 of the LRA provides a summary description of the system functions and a listed flow diagram. The flow diagram highlights the evaluation boundaries, and Table 3.3-46 of the LRA tabulates the components within the scope and subject to an AMR for the VO system. The corresponding drawings and UFSAR, however, show additional components that were not listed in Table 3.3-46 of the LRA.

The staff noted that the applicant did not identify housings for active components that require an AMR. The determination should consider whether failure of the housing would result in a failure of the associated active component to perform its intended function, and whether the housing meets the long-lived and passive criteria as defined in the rule.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-1, specific information concerning the exclusion of fan housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that cooling fans are not included in the AMR results tables in the LRA. The applicant also stated that cooling fans, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and determined that the applicant's basis for excluding fan housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the fan housings are passive long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-1.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-2, specific information concerning the exclusion of damper housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that dampers are not included in the AMR result tables in the LRA. The applicant goes on to state that ventilation dampers, without sub-component exceptions, are explicitly excluded from an AMR by 10 CFR 54.21. The staff reviewed this response and has determined that the applicant's basis for excluding damper housings is not consistent with the license renewal rule because the housings are relied upon to maintain pressure boundary integrity (as are valve bodies and pump casings) and are within scope. Furthermore, because the damper housings are passive long-lived components, they are subject to an AMR. The staff found this response unacceptable and characterized this issue as SER open item 2.3-2.

In its response to open items 2.3-1 and 2.3-2, dated October 28, 2002, the applicant provided AMR results tables for the turbine building ventilation system fan and damper housings that are in scope at McGuire and Catawba. On the basis of the information provided, the staff finds the applicant's response sufficient to resolve open items 2.3-1 and 2.3-2. The applicant indicated that the aging effects will be adequately managed such that the intended functions of the fans and dampers will be maintained consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the AMR results is documented in Section 3.3.37.2 of this SER. Because these open items apply to a number of ventilation systems, their resolution is documented in multiple sub-sections of Sections 2.2 and 2.3 of this SER.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-7(6), specific information concerning the exclusion of McGuire duct heater housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that duct heater housings should have been highlighted on flow diagrams to indicate they are within the scope of license renewal. The applicant further states the duct heaters consist of electric heating elements that are mounted inside the ductwork and do not have a pressure boundary function or any other component intended function for license renewal and are not subject to an AMR. Because the duct heater housings do not perform any intended function as described in 10 CFR 54.5, the staff finds the applicant's responses acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 2.3-7(7), specific information concerning the exclusion of pre-filter housings from the scope of license renewal and/or an AMR. In its response dated April 15, 2002, the applicant stated that the pre-filter housings are removable components within the air handling units. The applicant further explained that the filters are removable components within the air handling units (AHUs), and that the AHUs are listed in Table 3.3-46 of the LRA. The staff verified that the AHUs are listed in Table 3.3-46. Since the housings (AHUs) for these filters (which are removable) are in scope, and since the applicant performed an AMR on the AHUs, the staff finds the applicant's response acceptable.

Some components that are common to many systems, including the VO system, have been evaluated separately by the applicant in Section 2.1.2.1.2 of the LRA as "replace on condition" commodities. The staff's evaluation of applicant's treatment of these consumables is documented in Section 2.1.3.2.1 of this SER.

SER Section 2.4.3 documents the staff's evaluation of component supports for piping, cables, and equipment, that support the design and operation of the VO system. SER Section 2.5, "Scoping and Screening Results - Electrical and Instrumentation and Controls," documents the staff's evaluation of electrical and instrument components that support the VO system.

The staff reviewed the LRA, supporting information in the UFSARs, and the applicant's responses to RAIs. In addition, the staff sampled several components from the VO system flow diagram, as identified in Section 2.3.3.37 of the LRA, to determine whether the applicant properly identified the components within scope and subject to an AMR. No omissions were identified, except as identified in the RAIs.

#### 2.3.3.37.3 Conclusions

On the basis of its review, and with the open items identified in this SER section resolved, the staff has reasonable assurance that the applicant has adequately identified the VO system structures and components that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively.

### *2.3.3.38 Waste Gas System*

In LRA Section 2.3.3.38, "Waste Gas System," the applicant described the components of the waste gas system that are within the scope of license renewal and subject to an AMR. The system is described in Section 11.3 of the McGuire and Catawba UFSARs.

#### 2.3.3.38.1 Technical Information in the Application

The waste gas system removes fission product gases from radioactive fluids and contains these gases for a time sufficient to allow ample decay of the nuclides prior to release in accordance with applicable NRC regulations. The system is designed to control and minimize releases of radioactive effluent to the environment by reducing the fission product gas concentration in the reactor coolant which may escape during maintenance operations or from equipment leaks.

The applicant described the process for identifying the mechanical components that are within the scope of license renewal in LRA Section 2.1.1, "Scoping Methodology." As described in the scoping methodology, the applicant identified the portions of the waste gas system that are within the scope of license renewal on the P&IDs that are listed in LRA Section 2.3.3.38. Consistent with the method described in LRA Section 2.1.2, "Screening Methodology," the applicant listed the waste gas system mechanical components that are subject to an AMR in LRA Table 3.3-47. This table also lists the component functions. Specifically, the applicant identified the following component types as subject to an AMR—valve bodies, pipe, flow meters, hydrogen recombiners, hydrogen recombiner heat exchangers (tubes and shell), hydrogen recombiner heaters, hydrogen recombiner phase separators, hydrogen recombiner safety disc, orifices, strainers (for Catawba only), tubing, waste gas compressor heat exchangers (tubes, tube sheet, shell, and channel head) - for Catawba only, and waste gas decay tanks. All these components have the intended component function of PB, which is defined by the applicant as maintaining pressure boundary integrity so that sufficient flow and/or sufficient pressure are delivered, effecting containment isolation, or preventing interaction with safety-related equipment. In addition to the PB function, hydrogen recombiner heat exchangers have HT (heat transfer) function, hydrogen recombiner phase separators have WR (water removal) function in maintaining moisture levels, and orifices have TH (throttling) function.

2.3.3.38.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.38 to determine whether there is reasonable assurance that the applicant appropriately identified the portions of the waste gas system that are within the scope of license renewal in accordance with 10 CFR 54.4(a) and that the applicant appropriately identified the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the information provided in LRA Section 2.3.3.38, the applicable P&IDs referenced therein, and the McGuire and Catawba UFSARs, to determine if the applicant adequately identified the portions of the waste gas system that are within the scope of license renewal. The staff verified that those portions of the waste gas system that meet the scoping requirements of 10 CFR 54.4(a) were included within the scope of license renewal and were identified as such by the applicant in Section 2.3.3.38 of the LRA.

In LRA Section 2.3.3.38, the applicant listed applicable P&IDs for the waste gas system. The detailed diagrams are highlighted to identify those portions of the system that are within the scope of license renewal. The staff compared the LRA diagrams to the system drawings and descriptions in the UFSARs to ensure that they were representative of the waste gas system. To verify that the applicant included the applicable portions of the waste gas system within the scope of license renewal, the staff focused its review on those portions of the waste gas system that were not identified as within the scope of license renewal and verified that they did not meet the scoping criteria of 10 CFR 54.4(a). In addition, the staff reviewed the UFSARs for each facility to identify any additional system functions that were not identified in the LRA, and verified that the additional functions did not meet the scoping requirements of 10 CFR 54.4(a).

During a September 12, 2001, conference call (summarized by memorandum dated October 10, 2001), the staff asked the applicant to clarify whether the hydrogen recombining function for the combustible gas control is one of the intended system functions for the waste gas system. The hydrogen recombiner is listed in LRA Table 3.3-47 for an AMR, but the recombining function is not discussed in the system description of LRA Section 2.3.3.38 for waste gas system. The applicant responded that the system description in the LRA discussed the general function of the waste gas system, and not all of the intended system functions that met license renewal scoping criteria. The applicant indicated that the safety-related hydrogen recombiners are part of the containment air return exchange and hydrogen skimmer (VX) system at Catawba and McGuire, and that they can be located on piping and instrumentation drawings associated with the VX systems. The applicant further indicated that the WG hydrogen recombiners are within the scope of license renewal because they provide a pressure boundary function to retain radioactive gases. The applicant indicated that the safety-related hydrogen recombiners in the VX system are within the scope of license renewal, but the electrical portions are not subject to an AMR because they are heaters, which are classified as active components. The electrical components are located in enclosures that are considered component supports. The enclosures are seismically qualified and are included in LRA Table 3.5-3, page 3.5-19, Electrical & Instrument Panels & Enclosures. No aging effects or AMPs were identified for the VX hydrogen recombiner enclosures. The staff finds this clarification reasonable and provides its evaluation of the applicant's scoping and screening review for the VX system in Section 2.3.2.3.2 of this SER.

By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.38-2, the applicant to identify the intended system functions of the waste gas system that the applicant used for the scoping determination. In its response dated April 15, 2002, the applicant stated that the system intended functions were not used to determine whether the waste gas system is within the scope of license renewal. Instead, the applicant determined the portions of the waste gas system within the scope of license renewal according to the following scoping criteria—(1) portions of the systems that are safety-related (Duke Class A, B, or C), (2) portions of the systems that are designated as non-safety-related Class F piping, and (3) portions of the systems that are required to remain functional for fire protection. The staff finds the applicant's scoping criteria acceptable for the same reason provided in the staff's evaluation of radioactive waste management systems, which is documented in SER Section 2.3.3.24.2 pertaining to the liquid waste system.

LRA Table 3.3-47 identifies all the components subject to an AMR, but the following components are identified as for Catawba only—orifices for compressor seal and compressor make-up, waste gas compressor heat exchangers, valve bodies and strainers. Both Catawba and McGuire have the waste gas compressor. The staff reviewed Catawba drawing CN-1567-1.0 and found that the waste gas compressor and associated components (such as orifices, heat exchangers, piping, valves, and strainers) are designed to either Duke Class C or Class F components, therefore, those Catawba components are within the scope of license renewal. On the other hand, McGuire Drawing No. MCFD-1567-01.00 indicates that the waste gas compressor and associated components are designated as Duke Class E, therefore, those McGuire components are out of the scope according to LRA Section 2.1. The staff's evaluation of different Duke Classes is in SER Section 2.1. The staff noted that the differences in scoping the above components resulted from the differences in the current design basis, and both are acceptable according to 10 CFR 54.4(a).

On the basis of the above review, the staff did not identify any omissions by the applicant in the scoping of mechanical components according to 10 CFR 54.4(a).

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the waste gas system that were identified as within the scope of license renewal. The applicant used the screening methodology described in LRA Section 2.1.2 to identify the SCs subject to an AMR. The staff evaluation of the scoping and screening methodology is documented in Section 2.1 of this SER. In the LRA, the applicant identified the portions of the waste gas system that are within the scope of license renewal in the P&IDs and listed the mechanical components that are subject to an AMR and their intended component functions in LRA Table 3.3-47. The staff performed its review by sampling the SCs that the applicant determined to be within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended function without moving parts or without a change in configuration or properties, and that is not subject to replacement based on qualified life or specified time period, was excluded from an AMR.

During the staff's review of Table 3.3-47, the staff noted that the waste gas separators were not listed. By letter dated January 28, 2002, the staff requested, in RAI 2.3.3.38-1, the applicant to explain why the waste gas separators, which appeared to be passive, long-lived components, were highlighted in Catawba drawing CN-1567-1.0, but not listed in LRA Table 3.3-47. In its response dated April 15, 2002, the applicant stated that the waste gas separators are within the scope of license renewal and subject to an AMR. The applicant provided the AMR results for the waste gas separators as a supplement to Table 3.3-47. Since the applicant provided the AMR results for the waste gas separators, the staff finds this response acceptable. The staff's evaluation of the AMR results is documented in Section 3.3.38.2 of this SER. The staff did not identify any other omissions by the applicant in screening the components that are subject to an AMR in accordance with the requirement of 10 CFR 54.21(a)(1).

2.3.3.38.3 Conclusions

On the basis of its review of the information contained in LRA Section 2.3.3.38, the supporting information in the P&IDs, and the McGuire and Catawba UFSARs, as described above, the staff did not identify any other omissions by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant adequately identified those portions of the waste gas system that are within the scope of license renewal and the associated SCs that are subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

### 2.3.4 System Scoping and Screening Results: Steam and Power Conversion Systems

#### *2.3.4.1 Auxiliary Feedwater System*

In LRA Section 2.3.4.1, "Auxiliary Feedwater System," the applicant described the components of the auxiliary feedwater system that are within the scope of license renewal and subject to an AMR. These systems are identical for purposes of license renewal for both facilities without any notable differences in system design. Sections 10.4.9 and 10.4.10 of the Catawba and McGuire UFSARs, respectively, "Auxiliary Feedwater System," provide additional information concerning their respective auxiliary feedwater systems.

2.3.4.1.1 Technical Information in the Application

For both Catawba and McGuire, the auxiliary feedwater system is a nuclear safety-related system which serves as a backup to the feedwater system to ensure the safety of the plant and protection of equipment. The auxiliary feedwater system is essential to prevent an unacceptable decrease in the SG water levels, to reverse the rise in reactor coolant temperature, to prevent the pressurizer from filling to a water solid condition, and to establish stable hot standby conditions. The auxiliary feedwater system can be used during an emergency as well as during normal startup and shutdown operations. Using the methodology described in Section 2.1.2, "Screening Methodology," of the LRA, the applicant compiled a list of mechanical components within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire auxiliary feedwater systems are listed in Table 3.4-1 of the LRA. In LRA Table 3.4-1, the applicant lists the following 10 component commodity groups as subject to an AMR—motor-driven auxiliary feedwater pump casings, orifices, pipe, tubing, turbine-driven auxiliary feedwater pump casings, turbine-driven auxiliary feedwater pump bearing oil cooler (tubes), turbine-driven auxiliary feedwater pump bearing oil cooler (tube sheet), turbine-driven auxiliary feedwater pump bearing oil cooler (channel heads), turbine-driven auxiliary feedwater pump bearing oil cooler (shell), and valve bodies. LRA Table 3.4-1 also lists eductors as a component commodity group that is subject to an AMR for the Catawba auxiliary feedwater system. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. In addition, the orifices perform a throttling function and the turbine-driven auxiliary feedwater pump bearing oil cooler (tubes) perform a heat transfer function.

2.3.4.1.2 Staff Evaluation

The staff reviewed Section 2.3.4.1 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the auxiliary feedwater system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.1 of the LRA and the Catawba and McGuire UFSARs to determine if the applicant adequately identified the SSCs of the auxiliary feedwater system that are in the scope of license renewal. The staff verified that those portions of the auxiliary feedwater system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.1 of the LRA. The staff then focused its review on those portions of the auxiliary feedwater system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the auxiliary feedwater system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the auxiliary feedwater system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the auxiliary feedwater systems in Table 3.4-1 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed its intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the auxiliary feedwater system that are within the scope of license renewal in the drawings referenced in the LRA. The license renewal drawings were highlighted by the applicant to identify those portions of the auxiliary feedwater systems that meet at least one of the scoping criteria of 10 CFR 54.4. The staff compared the LRA drawings to the system drawings and the descriptions in the Catawba and McGuire UFSARs to ensure they were representative of the auxiliary feedwater systems. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that no structure or component that performs its intended functions without moving parts or without a change in configuration or properties and that are not subject to replacement based on qualified life or specified time period, was excluded from an AMR. The staff did not identify any omissions.

2.3.4.1.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.1 of the LRA, and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the Catawba and McGuire auxiliary feedwater systems that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.2 Auxiliary Steam System*

In the Catawba and McGuire LRA's, Section 2.3.4.2, "Auxiliary Steam System," the applicant described the components of the auxiliary steam system that are within the scope of license renewal and subject to an AMR. These systems are identical for purposes of license renewal for both facilities without any notable differences in system design.

2.3.4.2.1 Technical Information in the Application

The auxiliary steam system provides steam to various plant equipment, as required during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The auxiliary steam system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2). Using the methodology described in Section 2.1.2, "Screening Methodology," of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire auxiliary steam systems, are listed in LRA Table 3.4-2. In LRA Table 3.4-2, the applicant lists the following three component commodity groups as subject to an AMR—pipe, tubing, and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

2.3.4.2.2 Staff Evaluation

The staff reviewed Section 2.3.4.2 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the auxiliary steam system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.2 of the LRA to determine if the applicant adequately identified the SSCs of the auxiliary steam system that are in the scope of license renewal. The staff verified that those portions of the auxiliary steam system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.2 of the LRA. The staff then focused its review on those portions of the auxiliary steam system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the auxiliary steam system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the auxiliary steam system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the auxiliary steam systems in Table 3.4-2 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the auxiliary steam system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.2.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.2 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the Catawba and McGuire auxiliary steam systems that are within the scope of license renewal, and subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.4.3 Condensate System*

In LRA Section 2.3.4.3, “Condensate System,” the applicant described the components of the condensate system that are within the scope of license renewal and subject to an AMR. The Catawba UFSAR Section 10.4.7, Condensate and Feedwater System, provides additional information concerning the Catawba condensate system. McGuire has no Class F components in the Condensate System, therefore, no portion of the McGuire Condensate System is within the scope of license renewal. As a result, the following staff evaluation applies to Catawba only.

#### 2.3.4.3.1 Technical Information in the Application

The condensate system provides water to various plant equipment, as required, during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The condensate system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2). Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba condensate system are listed in Table 3.4-3. In LRA Table 3.4-3, the applicant lists the following two component commodity groups as subject to an AMR—pipe and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

#### 2.3.4.3.2 Staff Evaluation

The staff reviewed Section 2.3.4.3 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the condensate system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.3 of the LRA and the Catawba UFSAR to determine if the applicant adequately identified the SSCs of the condensate system that are in the scope of license renewal. The staff verified that those portions of the condensate system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.3 of the LRA. The staff then focused its review on those portions of the condensate system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the condensate system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the condensate system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the condensate systems in Table 3.4-3 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the condensate system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the condensate system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.3.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.3 of the LRA, and the supporting information in the Catawba UFSAR, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the condensate system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.4 Condensate Storage System*

In LRA Section 2.3.4.4, "Condensate Storage System," the applicant described the components of the condensate storage system that are within the scope of license renewal and subject to an AMR. McGuire has no Class F components in the condensate storage system, therefore, no portion of the McGuire condensate storage system is within the scope of license renewal. As a result, the following staff evaluation only applies to Catawba.

2.3.4.4.1 Technical Information in the Application

The condensate storage system provides a source of water for various plant equipment as required during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The condensate storage system is a non-safety system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2). Using the methodology described in Section 2.1.2, "Screening Methodology," of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba condensate storage system are listed in LRA Table 3.4-4. In LRA Table 3.4-4, the applicant lists the following two component commodity groups as subject to an AMR—pipe and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

2.3.4.4.2 Staff Evaluation

The staff reviewed Section 2.3.4.4 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the condensate storage system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.4 of the LRA to determine if the applicant adequately identified the SSCs of the condensate storage system that are in the scope of license renewal. The staff verified that those portions of the condensate storage system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.4 of the LRA. The staff then focused its review on those portions of the condensate storage system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the condensate storage system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the condensate storage system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the condensate storage systems in Table 3.4-4 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the condensate storage system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.4.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.4 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the condensate storage system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.5 Feedwater System*

In LRA Section 2.3.4.5, “Feedwater System,” the applicant described the components of the feedwater system that are within the scope of license renewal and subject to an AMR. Section 10.4.7, “Condensate and Feedwater System,” of the Catawba and McGuire UFSARs, provides additional information concerning their respective feedwater systems. These systems are identical for purposes of license renewal for both facilities without any notable differences in system design.

2.3.4.5.1 Technical Information in the Application

The feedwater system takes treated condensate system water, heats it further to improve the plant's thermal cycle efficiency, and delivers it at the required flow rate, pressure and temperature to the SGs. The feedwater system is designed to maintain proper vessel water levels with respect to reactor power output and turbine steam requirements. Using the methodology described in Section 2.1.2, “Screening Methodology,” of the Catawba and McGuire LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire feedwater systems, are listed in LRA Table 3.4-5. In LRA Table 3.4-5, the applicant lists the following five component commodity groups as subject to an AMR—orifices, pipe, reservoirs, tubing, and valve bodies. Table 3.4-5 also lists cavitating venturies as a component commodity group that is subject to an AMR for the Catawba feedwater system. Table 3.4-5 lists flow nozzles as a component commodity group that is subject to an AMR for the McGuire feedwater system. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

2.3.4.5.2 Staff Evaluation

The staff reviewed Section 2.3.4.5 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the feedwater system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.5 of the LRA and the Catawba and McGuire UFSARs, to determine if the applicant adequately identified the SSCs of the feedwater systems that are in the scope of license renewal. The staff verified that those portions of the feedwater system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.5 of the LRA. The staff then focused its review on those portions of the feedwater system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the feedwater system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the feedwater system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the feedwater systems in Table 3.4-5 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the feedwater system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the feedwater system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.5.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.5 of the LRA, and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the feedwater system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.6 Feedwater Pump Turbine Exhaust System*

In Section 2.3.4.6, “Feedwater Pump Turbine Exhaust System,” of the LRA, the applicant described the components of the feedwater pump turbine exhaust system that are within the scope of license renewal and subject to an AMR. Catawba UFSAR Section 10.3, Main Steam System, provides additional information concerning the design and operation of the Catawba feedwater pump turbine exhaust system. The McGuire feedwater pump turbine exhaust system is not described in the McGuire UFSAR.

2.3.4.6.1 Technical Information in the Application

The feedwater pump turbine exhaust system is essentially the same, and performs the same function, at Catawba and McGuire. The system provides a flow path for the exhaust steam from the turbine-driven auxiliary feedwater pump turbine. The steam to the turbine-driven auxiliary feedwater pump turbine is provided by the main steam system. Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire feedwater pump turbine exhaust systems are listed in LRA Table 3.4-6. In LRA Table 3.4-6, the applicant lists the following two component commodity groups as subject to an AMR—pipe and tubing. LRA Table 3.4-6 also lists expansion joint, expansion joint (bellows), orifices, and valve bodies as component commodity groups for Catawba that are subject to an AMR. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. The orifices also provide a throttling function.

2.3.4.6.2 Staff Evaluation

The staff reviewed Section 2.3.4.6 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the feedwater pump turbine exhaust system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.6 of the LRA, and the Catawba UFSAR, to determine if the applicant adequately identified the SSCs of the feedwater pump turbine exhaust system that are in the scope of license renewal. The staff verified that those portions of the feedwater pump turbine exhaust system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.6 of the LRA. The staff then focused its review on those portions of the feedwater pump turbine exhaust system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the Catawba UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the feedwater pump turbine exhaust system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the feedwater pump turbine exhaust system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the feedwater pump turbine exhaust systems in Table 3.4-6 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the feedwater pump turbine exhaust system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the Catawba and McGuire LRA flow diagrams to the system drawings and, for Catawba, the descriptions in the

Catawba UFSAR to ensure they were representative of the feedwater pump turbine exhaust system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.6.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.6 of the LRA, and the supporting information in the Catawba UFSAR, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the Catawba and McGuire feedwater pump turbine exhaust systems that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.7 Feedwater Pump Turbine Hydraulic Oil System*

In Section 2.3.4.7, “Feedwater Pump Turbine Hydraulic Oil System,” of the LRA, the applicant described the components of the feedwater pump turbine hydraulic oil systems that are within the scope of license renewal and subject to an AMR.

2.3.4.7.1 Technical Information in the Application

The feedwater pump turbine hydraulic oil system is essentially the same, and performs the same function, at Catawba and McGuire. The system provides emergency trip to the feedwater pump turbine steam valves and overspeed exercisers for ATWS mitigation. The turbine trip signal causes pressure to be bled off the hydraulic system causing the stop and governor valves to close. The components required to meet these functions are either active components or are passive components whose failure will not prevent the desired action from occurring. Failure of the pressure boundary of the valve bodies or piping will create a loss of hydraulic pressure causing the stop and governor valves to close, which is the safety function. Therefore, the components are in scope, but no AMR is required.

2.3.4.7.2 Staff Evaluation

The staff reviewed Section 2.3.4.7 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the feedwater pump turbine hydraulic oil system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.7 of the LRA to determine if the applicant adequately identified the SSCs of the feedwater pump turbine hydraulic oil system that are in the scope of license renewal. The staff verified that those portions of the feedwater pump turbine hydraulic oil system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.7 of the LRA. The staff then focused its review on those portions of the feedwater pump turbine hydraulic oil system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the feedwater pump turbine hydraulic oil system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the feedwater pump hydraulic oil system that are identified as within the scope of license renewal. The applicant identified that no AMR is required using the screening methodology described in Section 2.1 of the LRA. This is due to the components required to meet the ATWS mitigation functions are either active components or are passive components whose failure will not prevent the desired action from occurring. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the feedwater pump turbine hydraulic oil system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.7.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.7 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the Catawba and McGuire feedwater pump turbine hydraulic oil systems that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.8 Main Steam System*

In Section 2.3.4.8, “Main Steam System,” of the LRA, the applicant described the components of the main steam system that are within the scope of license renewal and subject to an AMR. In both the Catawba and McGuire UFSARs, Section 10.3, Main Steam Supply System, provides additional information concerning the main steam system.

2.3.4.8.1 Technical Information in the Application

The main steam system is essentially the same and performs the same function at Catawba and McGuire. The main steam system dissipates heat from the reactor coolant system, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, minimizes the containment temperature increase associated with a main steam line rupture within containment, and provides steam to the turbine driven auxiliary feedwater pump, as needed. Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the main steam system are listed in Table 3.4-7. In the LRA, Table 3.4-7, the applicant lists the following four component commodity groups as subject to an AMR—orifices, pipe, tubing, and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. The orifices also perform a throttling function.

2.3.4.8.2 Staff Evaluation

The staff reviewed Section 2.3.4.8 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the main steam system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.8 of the LRA, and the Catawba and McGuire UFSARs, to determine if the applicant adequately identified the SSCs of the main steam system that are in the scope of license renewal. The staff verified that those portions of the main steam system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.8 of the LRA. The staff then focused its review on those portions of the main steam system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the main steam system that should be included within the scope of license renewal in accordance with 10 CFR Part 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the main steam system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the main steam systems in Table 3.4-7 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the main steam system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and the descriptions in the UFSAR to ensure they were representative of the main steam system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.8.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.8 of the LRA and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the main steam system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.9 Main Steam Supply to Auxiliary Equipment*

In LRA Section 2.3.4.9, “Main Steam Supply to Auxiliary Equipment System,” the applicant described the components of the main steam supply to auxiliary equipment system that are within the scope of license renewal and subject to an AMR. Section 10.3, Main Steam Supply System, of the Catawba and McGuire UFSARs, provides additional information concerning the main steam supply to auxiliary equipment system.

2.3.4.9.1 Technical Information in the Application

The main steam supply to auxiliary equipment system is essentially the same, and performs the same function, at Catawba and McGuire. The system transfers steam to the turbine driven auxiliary feedwater pump turbine, so that the design bases of the Auxiliary Feedwater System can be met. Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire main steam auxiliary equipment systems are listed in LRA Table 3.4-8. In the LRA, Table 3.4-8, the applicant lists the following five component commodity groups as subject to an AMR—auxiliary feedwater pump turbine casing, orifices, pipe, tubing, and valve bodies. Table 3.4-8 also lists strainers as a component type that is subject to an AMR only for McGuire. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR. In addition, the orifices perform a throttling function and the strainers perform a filtration function.

2.3.4.9.2 Staff Evaluation

The staff reviewed Section 2.3.4.9 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the main steam supply to auxiliary equipment system structures and components (SSCs) that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.9 of the LRA, and the Catawba and McGuire UFSARs, to determine if the applicant adequately identified the SSCs of the main steam supply to auxiliary equipment system that are in the scope of license renewal. The staff verified that those portions of the main steam supply to auxiliary equipment system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.9 of the LRA. The staff then focused its review on those portions of the main steam supply to auxiliary equipment system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional main steam supply to auxiliary equipment functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the main steam auxiliary equipment system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the main steam auxiliary equipment system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the main steam supply to auxiliary equipment systems in Table 3.4-8 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the main steam supply to auxiliary equipment system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the main steam supply to auxiliary equipment that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the main steam supply to auxiliary equipment drawings, and the descriptions in the UFSAR, to ensure they were representative of the main steam auxiliary equipment system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.9.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.9 of the LRA, and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the main steam supply to auxiliary equipment system that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.10 Main Steam Vent to Atmosphere System*

In Section 2.3.4.10, “Main Steam Vent to Atmosphere System,” of the LRA, the applicant described the components of the main steam vent to atmosphere system that are within the scope of license renewal and subject to an AMR. Section 10.3, Main Steam Supply System, of the Catawba and McGuire UFSARs, provides additional information concerning the main steam vent to atmosphere system.

### 2.3.4.10.1 Technical Information in the Application

The main steam vent to atmosphere system is essentially the same, and performs the same function, at Catawba and McGuire. The system dissipates heat from the reactor coolant system, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, and minimizes the containment temperature increase associated with a main steam line rupture within containment. Using the methodology described in Section 2.1.2, “Screening Methodology,” of the LRA, the applicant compiled a list of mechanical component commodity groupings within the license renewal boundaries that are subject to an AMR and identified their intended functions. The mechanical components subject to an AMR, their intended functions, and materials of construction for the Catawba and McGuire main steam vent to atmosphere systems are listed in LRA Table 3.4-9. In LRA Table 3.4-9, the applicant lists the following three component commodity groups as subject to an AMR—pipe, tubing, and valve bodies. The applicant states that maintaining pressure boundary integrity is the intended function of the SCs subject to an AMR.

### 2.3.4.10.2 Staff Evaluation

The staff reviewed Section 2.3.4.10 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the main steam vent to atmosphere system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.10 of the LRA, and the Catawba and McGuire UFSARs, to determine if the applicant adequately identified the SSCs of the main steam vent to atmosphere system that are in the scope of license renewal. The staff verified that those portions of the main steam vent to atmosphere system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.10 of the LRA. The staff then focused its review on those portions of the main steam vent to atmosphere system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the main steam vent to atmosphere system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the main steam vent to atmosphere system that are identified as within the scope of license renewal. The applicant identifies and lists the SCs subject to an AMR for the main steam vent to atmosphere systems in Table 3.4-9 of the LRA using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the main steam vent to atmosphere system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that is within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the main steam vent to atmosphere system equipment drawings and the descriptions in the UFSAR to ensure they were representative of the main steam vent to atmosphere system. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any of the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.10.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.10 of the LRA, and the supporting information in the Catawba and McGuire UFSARs, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the main steam vent to atmosphere system that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.3.4.11 Main Turbine Hydraulic Oil System*

In Section 2.3.4.11, “Main Turbine Hydraulic Oil System,” of the LRA, the applicant described the components of the main turbine hydraulic oil system that are within the scope of license renewal and subject to an AMR. The Catawba and the McGuire main turbine hydraulic oil systems are not described in their respective UFSARs.

2.3.4.11.1 Technical Information in the Application

The main turbine hydraulic oil system is essentially the same, and performs the same function, at Catawba and McGuire. The system provides a means to trip the main turbine to mitigate the plant response to an ATWS event. The components in the main turbine hydraulic oil system are required to maintain pressure boundary integrity for normal system operation. However, an operational loss of pressure in the hydraulic oil system, or a failure of the pressure boundary of within scope components, will produce a turbine trip signal. Because a turbine trip signal is the system intended function, there are no component intended functions applicable to the components highlighted on the mechanical system flow diagrams. Therefore, no AMR is required.

2.3.4.11.2 Staff Evaluation

The staff reviewed Section 2.3.4.11 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the main turbine hydraulic oil system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.11 of the LRA to determine if the applicant adequately identified the SSCs of the main turbine hydraulic oil system that are in the scope of license renewal. The staff verified that those portions of the main turbine hydraulic oil system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.11 of the LRA. The staff then focused its review on those portions of the main turbine hydraulic oil system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the main turbine hydraulic oil system that should be included within the scope of license renewal in accordance with 10 CFR Part 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the main turbine pump hydraulic oil system that are identified as within the scope of license renewal. The applicant identified that no AMR is required using the screening methodology described in Section 2.1 of the LRA. This is a result of system design where an operational loss of pressure in the hydraulic oil system or a failure of the pressure boundary of within scope components will produce a turbine trip signal which is the intended function of the system. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the main turbine hydraulic oil system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.11.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.11 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the main turbine hydraulic oil system that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### *2.3.4.12 Main Turbine Lube Oil and Purification System*

In Section 2.3.4.12, “Main Turbine Lube Oil and Purification System,” of the LRA, the applicant described the components of the main turbine lube oil and purification system that are within the scope of license renewal and subject to an AMR. The Catawba and the McGuire main turbine lube oil and purification systems are not described in their respective UFSARs.

2.3.4.12.1 Technical Information in the Application

The main turbine lube oil and purification system is essentially the same, and performs the same function, at Catawba and McGuire. The system provides a means to trip the main turbine to mitigate the plant response to an ATWS event. The components in the main turbine lube oil and purification system are required to maintain pressure boundary integrity for normal system operation. However, an operational loss of pressure in the hydraulic oil system, or a failure of the pressure boundary within scope components, will produce a turbine trip signal. Because a turbine trip signal is the system intended function, there are no component intended functions applicable to the components highlighted on the mechanical system flow diagrams. Therefore, no AMR is required.

2.3.4.12.2 Staff Evaluation

The staff reviewed Section 2.3.4.12 of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the main turbine lube oil and purification system SCs that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff reviewed the text and diagrams submitted by the applicant in Section 2.3.4.12 of the LRA to determine if the applicant adequately identified the SSCs of the main turbine lube oil and purification system that are in the scope of license renewal. The staff verified that those portions of the main turbine lube oil and purification system that meet the scoping requirements of 10 CFR 54.4 are included within the scope of license renewal, and are identified as such by the applicant in Section 2.3.4.12 of the LRA. The staff then focused its review on those portions of the main turbine lube oil and purification system that were not identified as within the scope of license renewal to verify that they do not meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified in the LRA, and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. The staff found no omissions by the applicant, therefore, there is reasonable assurance that the applicant adequately identified all portions of the main turbine lube oil and purification system that should be included within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs that are subject to an AMR from among those portions of the main turbine lube oil and purification system that are identified as within the scope of license renewal. The applicant identified that no AMR is required using the screening methodology described in Section 2.1 of the LRA. This is a result of system design where an operational loss of pressure in the hydraulic oil system, or a failure of the pressure boundary of within scope components, will produce a turbine trip signal which is the intended function of the system. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff performed its review by sampling the SCs that the applicant determines as within the scope of license renewal, but not subject to an AMR, to verify that these SCs performed its intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on qualified life or specified time period.

The applicant identified the portions of the main turbine lube oil and purification system that are within the scope of license renewal in the drawings referenced in the LRA. The detailed flow diagrams were highlighted to identify those portions of the system that are within the scope of license renewal. The applicant highlighted those components which they believe perform at least one of the scoping requirements of 10 CFR 54.4. The staff sampled portions of the flow diagram that were not highlighted to verify that these components did not meet any the scoping criteria in 10 CFR 54.4. The staff did not identify any omissions.

2.3.4.12.3 Conclusions

On the basis of its review of the information contained in Section 2.3.4.12 of the LRA, as described above, no omissions by the applicant were identified. The staff concludes that there is reasonable assurance that the applicant adequately identified those portions of the main turbine lube oil and purification system that are within the scope of license renewal, and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

## 2.4 Scoping and Screening Results: Structures

### 2.4.1 Reactor Buildings

The reactor buildings include the concrete shield building, steel containment, and reactor building internal structures. The descriptions provided in the LRA are generically applicable to both McGuire and Catawba, except where differences are stated.

*2.4.1.1 Concrete Shield Building*

In the LRA, the applicant described the components of the concrete shield building for Catawba and McGuire that are within the scope of license renewal and subject to an AMR. The concrete shield building is further described in Section 3.8.1 of both the Catawba and McGuire UFSARs. The staff reviewed sections of the LRA and UFSARs pertaining to the concrete shield building to determine whether there is reasonable assurance that the applicant has identified and listed the structures and components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.1.1.1 Technical Information in the Application

The applicant described its methodology for identifying structures and components that are within the scope of license renewal in Section 2.0 of the LRA and the applicant states that the methodology is generically applicable to both McGuire and Catawba. LRA Section 2.1.1.1.2, “Safety-Related Structures,” specifically describes the applicant’s methods for identifying structures within the scope of license renewal that satisfy criteria in 10 CFR 54.4(a)(1). The applicant listed the structures within the scope of license renewal for McGuire in LRA Table 2.2-1, and for Catawba in LRA Table 2.2-2. Structures identified as not within the scope of license renewal are listed in Tables 2.2-3 and Table 2.2-4 of the LRA, for McGuire and Catawba, respectively. Based on the scoping methodology, the applicant, in Table 3.5-1 of the LRA, includes the reactor buildings within the scope of license renewal and describes the results of its scoping methodology in Section 2.4.1 in the LRA.

The concrete shield building (“shield building”) at McGuire and Catawba is a reinforced concrete structure composed of a right cylinder with a shallow dome and flat circular foundation. The shield building is part of the containment system that ensures that an acceptable upper limit of leakage of radioactive material is not exceeded under design basis events. In addition, it is designed to provide biological shielding as well as missile protection for the steel containment vessel. The annulus space between the shield building and the steel containment vessel provides control of containment external temperatures and pressures.

The applicant identified shield building structural components that require AMRs in Table 3.5-1 in the LRA. This table lists the types of structural components with their passive function(s) identified, including the AMR results with a link to the aging management programs and activities, if applicable. The applicant identified the following structural components for the shield building that are subject to an AMR—dome, foundation dowels (McGuire only), foundation mat, and shell wall.

In Table 3.5-1, the applicant lists the structural components of the McGuire and Catawba shield building that are within the scope of license renewal because they fulfill one or more of the following intended functions— (1) provides structural and/or functional support to safety-related equipment, (2) provides shelter/protection to safety-related equipment, (3) provides rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant, (4)serves as missile (internal or external) barrier, (5) provides structural and/or functional support to non-safety related equipment where failure of this component could directly prevent satisfactory accomplishment of any of the required safety-related functions, and (6) provides structural support and/or shelter to components relied on during certain postulated fire, anticipated transients without scram, and/or station blackout events.

As stated by the applicant, structural components of the shield building are subject to an AMR because they support equipment meeting the scoping criteria from the license renewal rule, 10 CFR Part 54.4(a)(1), (a)(2), and (a)(3), in a passive manner. As a result, they perform their intended function(s) without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.4.1.1.2 Staff Evaluation

The NRC staff reviewed Section 2.4.1.1 of the LRA, and the supporting information in Section 3.8.1 of the McGuire and Catawba UFSARs, to determine whether there is reasonable assurance that the structural components of the shield building were adequately identified within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), respectively.

The staff reviewed the structural components in LRA Table 3.5-1 for McGuire and Catawba to determine whether any other structures associated with the shield building meet the scoping criteria of 10 CFR 54.4(a), but were not included within the scope of license renewal. The staff then reviewed portions of the UFSAR descriptions to ensure that all structural components of the shield buildings had been adequately identified and that they were passive, long-lived and performed their intended functions without moving parts or with a change in configuration or change in properties and were subject to replacement based on qualified life or specified time period. The staff reviewed figures 3-11, 3-12, and 3-13 of Section 3.8.1 of the Catawba UFSAR, which depicts hot, cold, and feedwater penetrations. These penetrations were not identified in Table 3.5-1 of the LRA as within the scope of license renewal.

By letter dated January 28, 2002, the staff requested, in RAIs 2.4.1-1 and 2.4.1-4, additional information relating to the shield building penetrations for Catawba and McGuire. In its response dated March 11, 2002, the applicant provided a supplement to LRA Table 3.5-1 to add penetrations to the scope of license renewal for the shield building. The penetrations that are being added under the shield building in LRA Table 3.5-1 include subcomponents such as anchor rings, penetrations sleeves, pipe, caps, and restraint rings. These penetrations perform the following intended functions—

- to provide pressure boundary and/or fission product barrier
- to provide structural and/or functional support to safety-related equipment
- to provide structural and/or functional support to non-safety related equipment where failure of this component could directly prevent satisfactory accomplishment of any of the safety-related functions

The staff finds the addition of the shield building penetrations to be acceptable because these components are passive, long-lived, and perform their intended functions without moving parts or without a change in configuration or change in properties and are not subject to replacement based on qualified life or specified time period. The staff's evaluation of the AMR results is documented in Section 3.5.1.2.1 of this SER.

During its review of the UFSAR the staff noted that the shield building included a 3-foot thick removable concrete cover mounted on a track that covers the equipment hatch during operations. By letter dated January 28, 2002, the staff requested, in RAI 2.4.1-3, the applicant to explain why the concrete covers were not included within the scope of license renewal and subject to an AMR. In its response dated March 11, 2002, the applicant stated that the concrete cover described in the UFSAR is equipment hatch missile shield, and that it is within the scope of license renewal and subject to an AMR. The applicant stated that the tracks and other supporting structures also were within scope and subjected to an AMR. The missile shield is listed in LRA Table 3.5-1 under the Reactor Building Interior Structural Components; the tracks and other supporting structures are included with structural steel beams, plates, etc., in LRA Table 3.5-1 under the Reactor Building Interior Structural Components. The staff noted that, since LRA Section 2.4.1.1, Concrete Shield Building, did not provide a reference to LRA Section 2.4.1.3, Reactor Building Interior Structural Components, it was not clear that these exterior components were covered within the LRA. However, the staff reviewed this portion of LRA Table 3.5-1 and verified that the components of concern were included within the scope as indicated within the applicant's RAI response. Since the applicant indicated that the structures of concern were within scope and listed in the AMR results tables, the staff finds the applicant's clarification concerning the concrete cover, rails, and associated supports to be acceptable.

The NRC staff reviewed the LRA, supporting information in the UFSARs, and the applicant's response to the staff's RAI. In addition, the staff sampled several structures from LRA Tables 2.2-3 and 2.2-4, and several components from LRA Table 3.5-1, to determine whether the applicant properly identified the structures and components that are within the scope of license renewal and subject to an AMR. No omissions were identified.

2.4.1.1.3 Conclusions

On the basis of this review, the staff finds that there is reasonable assurance that the applicant has adequately identified SCs of the concrete shield building that are within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

*2.4.1.2 Steel Containment*

In LRA Section 2.4.1.2, “Steel Containment,” the applicant described the structures and components of the steel containment that serve as the primary containment and surround the reactor coolant system. The steel containment is further described in Section 3.8.2, “Steel Containment,” within both the Catawba and McGuire UFSARs. The staff reviewed sections of the LRA and UFSARs pertaining to the steel containment to determine whether there is reasonable assurance that the applicant has identified and listed the structures and components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.1.2.1 Technical Information in the Application

The applicant described its methodology for identifying structures and components that are within the scope of license renewal in Section 2.0 of the LRA and the applicant states that the methodology is generically applicable to both McGuire and Catawba. Section 2.1.1.1.2, “Safety Related Structures,” specifically describes the applicant’s methods for identifying structures within the scope of license renewal that satisfy criteria in 10 CFR 54.4(a)(1). The applicant lists the structures within the scope of license renewal for McGuire in LRA Table 2.2-1 and for Catawba in LRA Table 2.2-2. Structures identified as not within the scope of license renewal are listed in LRA Tables 2.2-3 and 2.2-4, for McGuire and Catawba, respectively. Based on the scoping methodology, the applicant, in Table 3.5-1 of the LRA, identifies the steel containment as within the scope of license renewal and lists the results of its scoping methodology in Table 3.5-1 of the LRA.

The steel containment at Catawba and McGuire is a freestanding welded seismic Category I structure with a vertical cylinder, hemispherical dome, and flat base. The primary containment is anchored to the shield building foundation by means of anchor bolts around the circumference of the cylinder base. The base of the steel containment is a liner plate encased in and anchored to the shield building foundation. The base liner plate functions as a leak-tight membrane and does not provide structural support to the steel containment. The applicant lists the structures and components of the steel containment in LRA Table 3.5-1 that are within the scope of license renewal because they provide pressure boundary and/or fission product barrier.

In Table 3.5-1 of the LRA, the applicant identifies the component types for the steel containment that require an AMR. This table lists the structural components with their passive function identified and its AMR results. The applicant has identified the following structural components for the steel containment that are subject to an AMR—bellows (penetrations), electrical penetrations, equipment hatch, fuel transfer tube penetration, mechanical penetrations, personnel air locks, and the steel containment vessel.

On the basis of the above-described methodology, the applicant identified the structures and components that are part of the steel containment and identified the intended functions of the SCs that are subject to an AMR in Table 3.5-1 of the LRA. As stated by the applicant, SCs of the steel containment are subject to an AMR because the steel containment is a Seismic Category I structure.  All Category I structures are within the scope of license renewal because they ensure the health and safety of the public and support or protect safety-related equipment in a passive manner.  As a result, they perform their intended function without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.4.1.2.2 Staff Evaluation

The NRC staff reviewed Section 2.4.1.2 of the LRA, and the supporting documentation in Section 3.8.2 of the McGuire and Catawba UFSARs, to determine whether there is reasonable assurance that the SCs of the steel containment were adequately identified within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1), respectively.

The staff reviewed the structural components in LRA Table 3.5-1 for McGuire and Catawba to determine whether any other structures associated with the steel containment meet the scoping criteria of 10 CFR 54.4(a), but were not included within the scope of license renewal.  The staff then reviewed portions of the UFSAR descriptions to ensure that all SCs of the steel containment had been adequately identified, and that they were passive, long-lived, and performed their intended functions without moving parts or with a change in configuration or change in properties, and were not subject to replacement based on qualified life or specified time period. The staff reviewed Section 3.8.2.1 of the McGuire and Catawba UFSARs, which lists the containment penetrations.  The staff found that SCs, such as seals on personnel locks, penetration sleeves, the purge penetration, double compressible seals, and bolted flanges, were not included in Section 2.4.1.2 nor Table 3.5-1 of the LRA as within the scope of license renewal. By letter dated January 28, 2002, the staff requested, in RAI2.4.1-5, additional information relating to the above-mentioned steel containment SCs for Catawba and McGuire.  In its response dated March 11, 2002, the applicant indicated that the SCs in question were subcomponents of other structures and components, or included within the component type listed in LRA Table 3.5-1.  The SCs were part of items, such as personnel air locks, steel containment penetrations, equipment hatch, fuel transfer penetration, and the purge penetration, and were included within the component type of mechanical penetrations listed in LRA Table 3.5-1.  The applicant indicated that these SCs, being subcomponents of SCs within the scope of license renewal, and their aging effects were managed in accordance with the Containment Leak Rate Testing Program identified in Appendix B of the LRA.  The staff finds the applicant’s response to be acceptable, since the subcomponents are within the scope and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The NRC reviewed the LRA, supporting information in the UFSARs, and the applicant’s response to the staff’s RAI.  The staff examined the structures and components in Table 3.5-1 of the LRA to determine whether they are the only SCs that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).  On the basis of the above review, the staff did not find omissions by the applicant.

2.4.1.2.3 Conclusion

On the basis of its review of the information submitted by the applicant in the LRA, and supporting information in the Catawba and McGuire UFSAR as described above, the staff did not identify any omissions by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant has adequately identified the SCs of the steel containment that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

### *2.4.1.3 Reactor Building Internal Structures*

In LRA Section 2.4.1.3, “Reactor Building Internal Structures,” the applicant described the structures and components within the steel containment that surround the reactor coolant system. The internal structures are further described in Sections 3.8.3, “Concrete and Structural Steel Internal Structures of the Steel Containment,” and 6.2.2, “Ice Condenser System,” within the McGuire UFSAR, and Sections 3.8.3 and 6.7, “Ice Condenser System,” of the Catawba UFSAR. The staff reviewed sections of the LRA and UFSARs pertaining to these internal structures to determine whether there is reasonable assurance that the applicant has identified and listed the structures and components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

#### 2.4.1.3.1 Technical Information in the Application

The applicant described its methodology for identifying the reactor building internal structures that are within the scope of license renewal in Section 2.0 of the LRA and the applicant states that the methodology is generically applicable to both McGuire and Catawba. Section 2.1.1.1.2, “Safety-Related Structures,” further describes the applicant’s methods for identifying structures within the scope of license renewal that satisfy criteria in 10 CFR 54.4(a)(1). The applicant lists the structures within the scope of license renewal for McGuire in LRA Table 2.2-1, and for Catawba in LRA Table 2.2-2. Structures identified as not within the scope of license renewal are listed in LRA Tables 2.2-3 and 2.2-4, for McGuire and Catawba, respectively. Based on the scoping methodology, the applicant, in Table 3.5-1 of the LRA, identifies the reactor building internal structures that are within the scope of license renewal and lists the results of its scoping methodology in the table.

The internal structures are comprised of a variety of reinforced concrete and structural steel structures. The internal structures enclose the reactor coolant system and provide biological shielding and acts as the pressure boundary for the lower, intermediate, and upper volumes of the steel containment interior. These structures also provide support for all major equipment, components, and systems located within the steel containment. The internal structures are supported by the shield building foundation. The applicant lists the internal structures within LRA Table 3.5-1 under ice condenser components and reactor building interior structural components that are within the scope of license renewal because they fulfill one or more of the following intended functions—

- to provide pressure boundary and/or fission product barrier
- to provide structural and/or functional support to safety-related equipment
- to provide shelter/protection to safety-related equipment
- to provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant
- to serve as missile (internal or external) barrier

- to provide structural and/or functional support to non-safety related equipment where failure of this component could directly prevent satisfactory accomplishment of any of the safety-related functions
- to provide a protective barrier for internal/external flood event
- to provide heat sink during SBO or design basis accidents
- to provide structural support and/or shelter to components relied on during certain postulated fire, anticipated transients without scram, and/or station blackout events

In the LRA, Table 3.5-1, the applicant identifies the component types for the internal structures that require an AMR. This table lists the SCs with their passive function identified and their AMR results. The applicant has identified SCs of the internal structures that are subject to an AMR, such as ice baskets, lower support structure, wear slab, anchorage, flood curbs, equipment pads, embedments, hatches, missile shields, pressure seals and gaskets, reinforced concrete beams, structural steel beams, sumps, and trusses.

On the basis of the above-described methodology, the applicant identified the structures and components that are part of the reactor building interior structural components and identified the intended functions of the SCs that are subject to an AMR in Table 3.5-1 of the LRA. As indicated by the applicant in LRA Table 3.5-1, SCs of the internal structures are subject to an AMR because they provide structural or functional support to safety-related equipment or equipment meeting 10 CFR 54.4(a)(2) or (3) in a passive manner. As a result, they perform their intended function without moving parts or without change in configuration or properties, and are not subject to periodic replacement based on a qualified life or specified time limit.

2.4.1.3.2 Staff Evaluation

The NRC staff reviewed Section 2.4.1.3 in the LRA, and the supporting information in Sections 3.8.3 of the Catawba and McGuire UFSAR, Section 6.2.2 and Section 6.7 of the McGuire and Catawba UFSARs, respectively, to determine whether there is reasonable assurance that the SCs of the reactor building internal structures were adequately identified within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The staff reviewed the component types in LRA Table 3.5-1 (e.g., sump liner, sump screens, embedment, checkered plate, anchorage, flood curbs, speciality doors, ice baskets, lower support structure, pressure seals and gaskets, fuel transfer canal liner plate, reinforced concrete beams, slabs, walls, and steel beams) to determine whether there were any other components associated with the reactor building internal structures and ice condenser that meet the scoping criteria of 10 CFR 54.4(a), but were not included within the scope of license renewal. The staff reviewed Section 2.4.1.3 of the LRA and the relevant portions of the Catawba and McGuire UFSARs. The staff also examined the component types listed in Table 3.5-1 of the LRA to determine whether they are the only SCs that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). On the basis of the above review, the staff did not find any omissions by the applicant.

In its response to SER open item 3.5-3, dated October 2, 2002, the applicant stated the following—

> With respect to the ice condenser wear slab, Duke has performed an additional review of the design of McGuire and Catawba and determined that the ice condenser wear slab is not within the scope of license renewal because it does not perform a license renewal function. The ice condenser slab is described in each station's UFSAR (Section 6.2.2 for McGuire and Section 6.7.1 for Catawba) as follows—
>
>> The wear slab is a concrete structure whose function is to provide a cooled surface as well as to provide personnel access support for maintenance and/or inspection. The wear slab also serves to contain the floor cooling piping.
>
> Therefore, no further aging management review of the ice condenser wear slab is required for license renewal.

The staff had discussed this determination by the applicant during a meeting on September 18, 2002. The applicant had noted that, for open item 3.5-3, it had re-evaluated the ice condenser wear slab and determined that the scoping criteria were not met for this component and that it should have been excluded from scope. The applicant explained its basis for this determination, and the staff did not identify any concerns with the decision. A summary of this meeting was issued in a memorandum dated November 18, 2002. Since the ice condenser wear slab does not perform an function that meets the license renewal scoping criteria, the staff concurs with the applicant's finding that the wear slab should not have been included within the scope of license renewal.

2.4.1.3.3 Conclusion

On the basis of its review of the information submitted by the applicant in the LRA, supporting information in the Catawba and McGuire UFSARs, and correspondence from the applicant as described above, the staff did not identify any omissions. Therefore, the staff finds that there is reasonable assurance that the applicant has adequately identified the SCs of the reactor building internal structures, which include the ice condensers, that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

### 2.4.2 Other Structures

Other structures are a collection of buildings and structures that house equipment necessary for the safe operation of the plant. In Section 2.4.2, "Other Structures," of the LRA, the applicant identified the following structures as within the scope of license renewal—

- auxiliary building
- condenser cooling water intake structure
- nuclear service water structures
- standby nuclear service water pond dam
- standby shutdown facility
- turbine building (including service building)
- unit vent stack
- yard structures

At both McGuire and Catawba, each of the above buildings and structures is similar in design and essentially performs the same function unless noted otherwise.

### *2.4.2.1 Auxiliary Buildings*

In Section 2.4.2.1, "Auxiliary Buildings," of the LRA, the applicant described the structures in the boundary of auxiliary building and identified the structures and components that are within the scope of license renewal and subject to an AMR for both McGuire and Catawba. These structures are further described in Section 3.8.4.1 of the McGuire UFSAR and Section 3.8.4 of the Catawba UFSAR.

#### 2.4.2.1.1 Technical Information in the Application

As described in Section 2.4.2.1 of the LRA, each plant has one auxiliary building, which is a seismic Category I reinforced concrete structure. The auxiliary building is shared by both reactor units. It houses the nuclear steam supply system equipment, electrical equipment, control building, fuel pools, and diesel generator related piping and cabling. The auxiliary building is integrally connected with the spent fuel building and main steam doghouse, and is linked with the diesel generator building by cable tunnels. In the LRA, the control building, diesel generator building, fuel building, ground water drainage system, main steam doghouse, and the UHI tank building are within the boundary of the auxiliary building for license renewal because they are either contained within, or attached to, the auxiliary building.

At both McGuire and Catawba, the control building is a part of the auxiliary building that houses the control room, battery room, and cable room. The control building is a seismic Category I reinforced concrete frame structure that is supported by a reinforced concrete mat foundation on rock and/or fill concrete. A frame structure is the structure that is connected by continuous rigid reinforced concrete beams, columns, walls, floor slabs, and roof slab.

The diesel generator buildings are the free-standing seismic Category I reinforced concrete structures. Each plant has two diesel generator buildings, each one houses two diesel generators which are separated by a reinforced concrete partition wall. The diesel generator building is supported by a reinforced concrete mat foundation on rock and/or fill concrete. Major portions of the diesel generator buildings are below grade. There are various equipment trenches, pits, and sumps at the base of the diesel generator buildings.

The fuel buildings are the seismic Category I reinforced concrete structures that provide storage for the new fuel and spent fuel. The spent fuel building houses the spent fuel pool and the cask handling area. A bridge crane is provided for the fuel cask handling. Each spent fuel pool has reinforced concrete walls lined with stainless steel liner plates. The upending canal can be de-watered independent of the main pool. The roof of the spent fuel pool is designed for missile protection. At McGuire, the reinforced concrete structure encloses the spent fuel pool with the north end open to the cask handling area and new fuel storage vault. At Catawba, the spent fuel building encloses the pool with the east end open to the new fuel building which is a seismic Category I reinforced concrete structure.

The groundwater drainage system maintains normal groundwater level near the base of the auxiliary building and diesel generator buildings. The groundwater drainage system is an integral part of the building foundation that consists of a grid of collecting trenches below the foundation surround on all sides by concrete, fill concrete, or rock. These groundwater under-drain systems are further described in Section 2.4.13 of both the McGuire UFSAR and the Catawba UFSAR. Three groundwater sumps are provided along the perimeter of the auxiliary building for collecting groundwater.

The main steam doghouses are seismic Category I reinforced concrete structures that house the high-pressure main steam and feedwater piping. Each reactor unit has one inside doghouse, one outside doghouse, and an UHI tank building. At Catawba, the inside doghouse and outside doghouse are located on the opposite sides of their respective reactor buildings. The inside doghouse is cast integrally with the auxiliary building and is free standing above a certain elevation. The outside doghouse is cast integrally with the UHI tank building, which houses the UPI tank and its components. The outside doghouse and the UHI tank building are separated by a reinforced concrete wall and are supported by a single mat foundation on rock and/or fill concrete. The Catawba UHI tank was originally designed to store the water to be used for removing decay heat from reactor core after a design basis event. This system has been functionally disabled. However, other systems contained within the UHI tank building, such as portions of the hydrogen bulk storage, are within the scope of license renewal. Therefore, the UHI tank building at Catawba is within the scope of license renewal. The LRA does not address the UHI tank building for McGuire.

The applicant identified the buildings and structures within the scope of license renewal in Table 2.2-1 of the LRA for McGuire and in Table 2.2-2 of the LRA for Catawba. The applicant listed structural component types, component intended functions, and their construction materials in Table 3.5-2 of the LRA as the results of AMR for these buildings. These structural components listed in the table meet the intent of 10 CFR 54.4(a) for license renewal because they perform one or more of the intended functions specified in the table. They also meet the criteria of 10 CFR 54.21(a)(1) because they are passive and long-lived components.

2.4.2.1.2 Staff Evaluation

The staff reviewed Section 2.4.2.1 of the LRA and each plant's UFSAR to determine if the applicant adequately implemented its methodologies as described in Section 2.1 of the LRA, such that there is reasonable assurance that the structural components and commodities within the boundary of the auxiliary building have been properly identified as within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively. After completing its initial review, the staff determined that additional information was needed to complete its review.

By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-1, general and detailed structural drawings that would depict the structures addressed in Section 2.4.2 of the LRA. The applicant provided general arrangement plot plans to the staff, and the staff found these drawings to be sufficient to support the staff's review. In a February 21, 2002, conference call, (summarized by memorandum dated March 6, 2002) the staff recast RAI 2.4.1-1 to refer to general drawings only, since detailed drawings were requested in RAI 2.4.1-12. In its response to RAI 2.4.1-1, dated March 11, 2002, the applicant referenced the drawings it had provided to the staff, as follows—

CN-1003-10, Catawba Nuclear Station, Plot Plan, General Arrangement
MC-1003-1, McGuire Nuclear Station, Plot Plan, General Arrangement
Figure 1 from CNS-1139.00-00-0004, "Auxiliary Building Structures Plan of Component Structures"
Figure 1 from MCS-1154.00-00-0004, "Auxiliary Building Structures Plan of Component Structures"

Because the applicant identified these drawings as classified commercial information related to the physical protection of McGuire and Catawba nuclear stations, the drawings were not attached to the applicant's response and are not accessible by the public. Since the applicant's drawings were sufficient to support the staff's review, the staff found the applicant's response to RAI 2.4.1-1 acceptable.

Section 2.4.2.1 of the LRA states that the groundwater drainage system is provided for the auxiliary building and diesel generator building to maintain normal groundwater level near the base of these structures. However, the applicant did not address whether the foundation mat and the lower portion of the walls have expansion joints, water-stops, or waterproofing membranes (or elastomer components, if any), that can prevent groundwater in-leakage into the concrete construction joints. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-3, the applicant to provide additional information on structural sealant or elastomer components for the below-grade construction joints. The staff asked whether the water-stops and the components of the under-drain groundwater system should be included in Table 3.5-2 of the LRA for an AMR.

In its response dated March 11, 2002, the applicant stated that water-stops are provided in the below-grade sections of the structures. Water-stops are addressed in Section 2.1.2.2 of the LRA. However, water-stops are not uniquely identified in the LRA. They are the sub-components of foundation or wall and are addressed with the foundation or wall within which the water-stops are located. The foundations and walls are within the scope and subject to an AMR for license renewal, as are the subcomponents. The staff finds the applicant's response acceptable because the components in concern were included in the scope and subject to an AMR for license renewal.

Section 2.4.2.1 of the LRA states that the main steam doghouses and UHI tank building are within the scope of license renewal. However, the applicant did not describe these structures, and Table 3.5-2 of the LRA does not define which of the components in the table are applicable to these structures. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-4, that the applicant provide additional information for the main steam doghouse and UHI tank building.

In its response, the applicant stated that the components listed in Tables 3.5-2 and 3.5-3 of the LRA are applicable to the main steam doghouse and UHI tank building unless noted otherwise. For example, equipment pads identified in the table are the components for all the structures, including the main steam doghouse and UHI tank building. For completeness, the applicant identified the following components and commodities for the main steam doghouse and UHI tank building—equipment pads, fire walls, foundations, hatches, reinforced concrete beams, columns, floor slabs and walls, roof slabs, anchorage, checkered plate, embedment, expansion anchors, fire doors, structural steel beams, columns, steel plates and trusses, fire barrier penetration seals, cable tray and conduit supports, electrical and instrument panels and enclosures, equipment component supports, HVAC duct supports, instrument line supports, instrument racks and frames, pipe supports, stair, platform, and grating supports. The staff finds the applicant's response acceptable because the applicant identified the components within the structures (main steam doghouse and UHI tank building), and the staff verified that these components are included in the LRA tables.

Table 2.2-1 of the LRA does not identify a UHI tank building for McGuire. The staff asked the NRC's scoping and screening inspection team to verify why the McGuire UHI tank building was not in scope. As is documented in NRC Inspection Reports 50-369/02-05, 50-370/02-05, 50-413/02-05 and 50-414/02-05, issued May 6, 2002 (ADAMS Accession No. ML021280003), the applicant provided McGuire design drawings MC-1204-2-A and MC-1204-3-A (general arrangement plan for the auxiliary building) to the inspector for review. These drawings indicated that the UHI tanks are located in the McGuire auxiliary building, not in a separate building. The drawings depicted the UHI tanks as an "accumulator water tank" and an "accumulator gas tank." To demonstrate that these tanks were associated with the UHI system, the applicant furnished an excerpt from the fire hazards analysis pertaining to fire area 21, which linked the accumulator water and gas tanks to the UHI system. Based on the scoping and screening inspection, the staff confirmed that the UHI tank building is in scope only for Catawba because this building does not exist at the McGuire plant site.

The staff has completed its review of the information presented in Section 2.4.2.1 of the LRA, the supporting information in each plant's UFSAR, the applicant's response to RAIs, and the drawings referenced in the SER section. As a result of its review, the staff did not identify any omissions by the applicant related to scoping the structures for license renewal as defined under 10 CFR 54.4(a). The staff also found that all the components and commodities in scope were subject to an AMR because the applicable intended functions are performed without moving parts or without a change of configuration or properties, and they are not replaced based on a qualified life or specified time period.

2.4.2.1.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified those structures in the boundary of the auxiliary building that are within the scope of license renewal and their associated components and commodities that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.4.2.2 Condenser Cooling Water Intake Structure*

In Section 2.4.2.2, "Condenser Cooling Water Intake Structure," of the LRA, the applicant described the condenser cooling water intake structure and identified the structural components and commodities that are within the scope of license renewal and subject to an AMR.

2.4.2.2.1 Technical Information in the Application

At McGuire, the condenser cooling water intake structure houses three main fire pumps, which are relied on during certain postulated fire event in compliance with 10 CFR 50.48 for fire protection. The condenser cooling water intake structure is a seismic Category III structure that is constructed of carbon steel and reinforced concrete. Seismic Category III structure is not designed to withstand design basis seismic loadings. The applicant determined that the fire pump rooms at east and west sides of the condenser cooling water intake structure are the only portions of the intake structure that are within the scope of license renewal, because they have the safety function for fire protection.

At Catawba, the low pressure service water intake structure houses the components of the conventional low pressure service water system and fire pumps. The applicant determined that only the portion of the structure that supports the fire pumps is within the scope of license renewal. The low pressure service water intake structure is included in the yard structures for license renewal.

The structural components, component intended functions, and material of construction listed in Table 3.5-2 of the LRA are applicable to the condenser cooling water intake structure.

2.4.2.2.2 Staff Evaluation

The staff reviewed Section 2.4.2.2 of the LRA and each plant's UFSAR to determine if there is reasonable assurance that the applicant has properly identified the structures and listed the components of the condenser cooling water intake structure for each plant to meet the requirements of 10 CFR 54.21(a)(1). After completing its initial review, the staff determined that additional information was needed to complete its review.

Section 2.4.2.2 of the LRA states that the McGuire condenser cooling water intake structure is a Category III structure, and the fire pump rooms are the only parts of the intake structure that are within the scope of license renewal. However, there is insufficient information in the LRA regarding the structural components that house and support the fire pumps. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-5, the applicant to provide additional information on the components listed in Table 3.5-2 of the LRA that are applicable to the fire pump rooms.

In its response dated March 11, 2002, the applicant stated that the condenser cooling water intake structure provides structural support to the three main fire pumps, which perform a function that is required by the fire protection rule, 10 CFR 50.48. The fire pump rooms are located on the outermost east and west sides of the condenser cooling water intake structure. For completeness, the applicant identified the following components of the fire pump rooms subject to an AMR—foundation, foundation dowels, equipment pads, reinforced concrete beams, columns, floor slabs and walls, roof, anchorage, cable tray and conduit and their supports, electrical and instrument panels and their enclosures, embedment, expansion anchors, and pipe supports. The staff reviewed Tables 3.5-2 and 3.5-3 of the LRA and found that these components were listed therein.

Section 2.4.2.2 of the LRA states that the fire pumps at Catawba are supported by the low-pressure service water intake structure, which is included in the yard structures. Section 2.4.2.8, "Yard Structures," of the LRA states that the Catawba fire pumps and their support structure are within the scope of license renewal. However, neither LRA section describes the low-pressure service water intake structure. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-6, the applicant to describe the structure and identify the components that are subject to an AMR.

In its response dated March 11, 2002, the applicant stated that the low-pressure service water intake structure provides structural support for the components of the conventional low-pressure service water system and the fire pumps. The conventional low-pressure service water system is not within the scope of license renewal. The fire pumps are required for fire protection and are within the scope of license renewal. The applicant listed the following components which protect and support the fire pumps—foundation, equipment pads, reinforced concrete beams, columns, floor slabs and walls, anchorage, cable tray and conduit and their supports, electric and instrument panels and their enclosures, embedment, expansion anchors, and pipe supports. The staff's review found that these components were listed in Tables 3.5-2 and 3.5-3 of the LRA.

The staff has completed its review of the applicant's submittals and did not find any omissions by the applicant related to scoping the structures of the condenser cooling water intake structure that were included in the scope of license renewal as defined in 10 CFR 54.4(a). The staff also found that all the components and commodities of the condenser cooling water intake structure in scope are subject to an AMR because they perform applicable intended function(s) without moving parts or without a change in configuration or properties, and they are not replaced on a qualified life or specified time period.

2.4.2.2.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified those portions of the structures in the boundary of the condenser cooling water intake structures for both McGuire and Catawba that are within the scope of license renewal, and their associated components and commodities that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.4.2.3 Nuclear Service Water Structures*

In Section 2.4.2.3, "Nuclear Service Water Structures," of the LRA, the applicant described the nuclear service water structures and identified the structures and components that are in scope and subject to an AMR for license renewal.

2.4.2.3.1 Technical Information in the Application

At McGuire, the nuclear service water structures include both the standby nuclear service water pond intake structure and the standby nuclear service water pond discharge structure. The nuclear service water pond intake structure is a completely submerged, reinforced concrete structure located at the bottom of the water pond east of the standby nuclear service water pond dam. The intake structure is designed to act as the head-wall of the nuclear service water intake pipes that provides missile protection for the pipes. The service water pond discharge structure is located at the northern portion of the water pond near the water surface. The discharge structure has a concrete head-wall that prevents erosion around the discharge pipes and has soil backfill over the stepped concrete slab that provides missile protection for the discharge pipes.

At Catawba, the nuclear service water structures include the following—

- nuclear service water and standby nuclear service water pump structure
- nuclear service water conduit manholes

- nuclear service water intake structure
- standby nuclear service water discharge structure
- standby nuclear service water intake structure
- standby nuclear service water pond outlet

The Catawba nuclear service water and standby nuclear service water pump structure is a reinforced concrete enclosure founded on solid rock. The exterior and interior walls and reinforced concrete roof are designed for missile protection. The reinforced concrete roof has hatches which are designed with fire barrier and missile barrier. There are pressure doors in the service water pump enclosure that are designed to withstand tornado suction pressure. The interior wall, and some of the exterior walls of the pump enclosure, are also designed as fire barriers.

The Catawba nuclear service water conduit manholes and the nuclear service water intake structure are the seismic Category I reinforced concrete structures. The nuclear service water intake structure is designed to house the nuclear service water intake pipes and is submerged in the plant intake channel. The conduit manholes are the small reinforced concrete structures that are located underground with access opening at grade level for cable installation and removal. The nuclear service water intake structure acts as an earth/silt retaining wall that provides missile protection for the intake pipe. An intake chamber and screens are provided at the pipe-end to stop fish impingement.

The Catawba standby nuclear service water discharge structures are the seismic Category I reinforced concrete head-walls. Two discharge structures are provided within the pond that provide missile protection for the discharge piping. Each discharge structure houses two standby nuclear service water discharge pipes and acts as an earth retaining wall.

The Catawba standby nuclear service water intake structures are the seismic Category I reinforced concrete box-shaped structures. The intake structure acts as an earth/silt retaining wall that holds the nuclear service water intake pipe and protects the intake pipe from missile strikes. The intake structure has an intake chamber and screens at the pipe-end to stop fish impingement.

The Catawba standby nuclear service water pond outlet is a seismic Category I structure that consists of a steel pipe located at the south abutment of the standby nuclear service water pond dam with a reinforced concrete head-wall on the pond side and a reinforced concrete end-wall on the Lake Wylie side. The head-wall is designed to contain and protect the pipe and support the missile shield. The pond outlet supports the weir and its missile shield, and contains the trash rack.

The applicant identified all the structures within the scope of license renewal in Table 2.2-1 of the LRA for McGuire, and in Table 2.2-2 of the LRA for Catawba. The structural components and commodities listed in Tables 3.5-2 and 3.5-3 of the LRA are applicable to the nuclear service water structures.

2.4.2.3.2 Staff Evaluation

The staff reviewed Section 2.4.2.3 of the LRA and each plant's UFSAR to determine if the applicant adequately identified the structures of the nuclear service water structures for both plants that are within the scope of license renewal in accordance with 10 CFR 54.4(a), and their components and commodities that require an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing its initial review, the staff determined that additional information was needed to complete its review.

Section 2.4.2.3 of the LRA states that the nuclear service water structures at Catawba include several structures. It is not clear that the structures described in this section cover all the nuclear service water structures in scope. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-7, the applicant to identify all the structures that are within the scope of license renewal and the components in Table 3.5-2 of the LRA that are applicable to the nuclear service water structures.

In its response dated March 11, 2002, the applicant stated that Table 2.2-2 of the LRA lists all of the Catawba structures that are within the scope of license renewal. Table 2.2-4 of the LRA lists all of the Catawba structures that are not within the scope of license renewal. The combination of the two tables contains all the structures of Catawba. The components listed in Tables 3.5-2 and 3.5-3 of the LRA are applicable to the nuclear service water structures, unless noted otherwise. For completeness, the applicant listed the following components of the nuclear service water structures subject to an AMR—anchorage; checkered plate; embedments; flood curbs; equipment pads; fire walls; foundations; hatches; manholes and covers; missile shields; reinforced concrete beams, columns, floor slabs, and walls; roof slabs; cable tray and conduit; cable tray and conduit supports; expansion anchors; fire doors; flood, pressure and specialty doors; electrical and instrument panels and enclosures; equipment component supports; stairs, platforms, and grating supports; HVAC duct supports (Catawba only); instrument line supports; pipe supports; instrument racks and frames; structural steel beams, columns, plates and trusses; trash rack and screens; fire barrier penetration seals (Catawba only); flood seals; and roofing.

The staff reviewed Tables 2.2-2 and 2.2-4 of the LRA for Catawba, and Tables 2.2-1 and 2.2-3 for McGuire, and found that the structures within the nuclear service water structures are all identified in Section 2.4.2.3 of the LRA. Some of the components provided by the applicant are listed in Table 3.5-3 of the LRA as the component supports that will be further reviewed in Section 2.4.3 of this report. As a result of this review, the staff did not find any omissions by the applicant related to scoping the structures. The staff’s review also found that all the structural components in scope were identified as being subject to an AMR because they are all passive and long-lived components.

2.4.2.3.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the structures and components associated with the nuclear service water structures that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.4.2.4 Standby Nuclear Service Water Pond Dam*

In Section 2.4.2.4, “Standby Nuclear Service Water Pond Dam,” of the LRA, the applicant described the standby nuclear service water pond dam at each plant site and identified its structures and components that are within the scope of license renewal and subject to an AMR.

2.4.2.4.1 Technical Information in the Application

At both Catawba and McGuire, the standby nuclear service water pond dam performs the same function that provides ultimate heat sink following a postulated LOCA or loss of Lake Norman or Lake Wylie. The standby nuclear service water pond dam is an earthen embankment that is designed as a seismic Category I structure. At each plant, the dam impounds water within the standby nuclear service water pond to provide an alternate source of water for the standby nuclear service water system.

2.4.2.4.2 Staff Evaluation

The staff reviewed Section 2.4.2.4 of the LRA to determine if there is reasonable assurance that the components comprising the standby nuclear service water pond dam have been properly identified as within the scope of license renewal and subject to an AMR. After completing its initial review, the staff determined that additional information was needed to complete its review.

In Table 3.5-2 of the LRA, the applicant lists "earthen embankment" as the component subject to an AMR. No other components are listed in the table. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-8, the applicant to indicate if other components of the nuclear service water pond dam that may perform an intended function should be listed in the table, such as drain pipes, observation wells, and piezometers, if any.

In its response dated March 11, 2002, the applicant stated that the earthen embankment is the component of the standby nuclear service water pond dam that performs the intended function to provide ultimate heat sink following a LOCA or loss of Lake Norman or Lake Wylie. Other components, such as drain pipes, observation wells, and piezometers, are not relied upon for the standby nuclear service water pond dam to perform their intended function, but are used as part of the aging management program to verify that the dam is performing the function as designed. Consequently, these components are not included in the scope of license renewal and are not subject to an AMR. However, they are included as an integral part of the standby nuclear service water pond dam inspection program as described in Appendix B, Section B.3.30 of the LRA.

The staff reviewed the information presented in Section 2.4.2.4 of the LRA and the additional information provided by the applicant in response to the staff's question. As a result of this review, the staff finds that the applicant's methodology for scoping the standby nuclear service water pond dam is acceptable because the associated components not listed in the table monitor the dam performance but do not support the intended function of the standby nuclear service water pond dam. Therefore, the staff found no omissions of structural components by the applicant that are required to be in scope and subject to an AMR for license renewal.

2.4.2.4.3 Conclusions

On the basis of this review, the staff concludes that inclusion of the structure of the standby nuclear service water pond dam in the scope of license renewal meets the criteria of 10 CFR 54.4(a), and inclusion of the earthen embankment as the component subject to an AMR meets the criteria of 10 CFR54.21(a)(1). Therefore, the staff concludes that the applicant's scoping and screening of the standby nuclear service water pond dam is acceptable.

*2.4.2.5 Standby Shutdown Facility*

In Section 2.4.2.5, “Standby Shutdown Facility,” of the LRA, the applicant described the structure that houses the standby shutdown equipment and identifies the structures and components that are within the scope of license renewal and subject to an AMR.

2.4.2.5.1 Technical Information in Application

At both McGuire and Catawba, the standby shutdown facility structure houses a dedicated diesel generator, and its supporting equipment, and the batteries relied on during certain postulated events. The standby shutdown system in the enclosure is used to maintain safe shutdown conditions from outside of the control room in the event of a postulated fire, sabotage, or flooding events. The standby shutdown facility structure is a steel-frame and masonry building that consists of a diesel generator room, electrical equipment room, battery room, and the shared equipment for both units. The building is a seismic Category III structure that is not designed to withstand design basis seismic loadings.

The structural components, component intended functions, and material of construction listed in Table 3.5-2 of the LRA are applicable to the standby shutdown facility structure.

2.4.2.5.2 Staff Evaluation

The staff reviewed Section 2.4.2.5 of the LRA and each plant’s UFSAR to determine if the applicant adequately identified the structures of the standby shutdown facility that are within the scope of license renewal in accordance with 10 CFR 54.4(a), and the structural components that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). After completing its initial review, the staff determined that additional information was needed to complete its review.

The standby shutdown facility structure is within the scope of license renewal because it provides structural support and/or shelter to components relied on during certain postulated events (e.g., postulated fire, ATWS, and/or SBO). Section 2.4.2.5 of the LRA states that the standby shutdown facility structure is a steel-frame and masonry structure. However, LRA Table 3.5-2 of the LRA only specifies “the block walls” as the components of the standby shutdown facility structure. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-9, the applicant to identify other components in the table that are applicable to the standby shutdown facility structure.

In its response dated March 11, 2002, the applicant stated that the components listed in Tables 3.5-2 and 3.5-3 of the LRA are applicable to the standby shutdown facility structure unless noted otherwise. The components of the standby shutdown facility structure subject to an AMR—anchorage; battery racks; cable tray and conduit and their supports; control boards; electrical and instrument panels and enclosures; embedments; equipment component supports; equipment pads; expansion anchors; foundations; hatches; checkered plate; fire walls; flood curbs; flood seals; roofing HVAC duct supports; instrument line supports; instrument racks and frames; masonry block walls; pipe supports; reinforced concrete beams, columns, floor slabs, and walls; roof slabs; stairs, platforms, and grating supports; and structural steel beams, columns, plates, and trusses.

The staff reviewed Tables 3.5-2 and 3.5-3 of the LRA and the additional information submitted by the applicant in response to the staff's question. The staff examined the components and commodities of the standby shutdown facility structure provided by the applicant and found that all portions of the structure were identified in the LRA tables as within the scope of license renewal and subject to an AMR by the applicant. Some of the components are within the category of component supports that will be further reviewed in Section 2.4.3 of this report.

As a result of the above review, the staff did not find any omissions by the applicant related to scoping of the standby shutdown facility structure. The staff's review also found that these long-lived and passive structures and components identified as within the scope of license renewal were subject to an AMR.

2.4.2.5.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the standby shutdown facility structures for both McGuire and Catawba that are within the scope of license renewal, and their associated components and commodities that are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

*2.4.2.6 Turbine Buildings (including Service Building)*

In Section 2.4.2.6, "Turbine Buildings (including Service Building)," of the LRA, the applicant described the structures of the turbine building, and service building and identified the structures and components that are within the scope of license renewal and subject to an AMR.

2.4.2.6.1 Technical Information in the Application

At both McGuire and Catawba, the turbine buildings and service building are seismic Category III structures that are not designed to withstand design basis seismic loadings. There are two turbine buildings at each plant site (one for each unit) that house the turbine generators, condensers, feedwater heaters, pumps, and associated components and equipment. The turbine building itself is constructed of a steel frame superstructure and a reinforced concrete substructure that is supported by a mat foundation bearing on dense soil, partially weathered rock, and rock. The service building is a two-story relatively light steel frame structure that is located between the two turbine buildings. At McGuire, the southern portion of the service building and the southwest portion of the McGuire-1 turbine building are underlaid by compacted soil and are supported on the end bearing caissons. The intended function of the turbine building (including service building) is to provide structural support and/or shelter to the components relied on during certain postulated fire, anticipated transients without scram, and/or station blackout events. The applicant determined that the turbine buildings (including service building) at each plant site are within the scope of license renewal.

The applicant listed the structural components in Table 3.5-2 of the LRA for other structures that are applicable to the turbine building and service building. The applicant specified in the table that the foundation caissons are for McGuire turbine building only and the flood, pressure, and specialty doors are applicable to both the turbine building and auxiliary building.

2.4.2.6.2 Staff Evaluation

The staff reviewed Section 2.4.2.6 of the LRA and each plant's UFSAR to determine if the applicant adequately identified the structures of the turbine building and service building that are within the scope of license renewal in accordance with 10 CFR 54.4(a), and their structural components, that are subject to an AMR in accordance with 10 CFR 54.21(a)(1). After completing its initial review, the staff determined that additional information was needed to complete its review.

Section 2.4.2.6 of the LRA states that the turbine building (including service building) are Category III structures. However, the relationship between the turbine building and the service building is not clearly defined in the LRA. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-10, the applicant to describe these buildings and identify the components in Table 3.5-2 of the LRA that are applicable to the turbine building and service building (other than the components specified for turbine building only).

In its response dated March 11, 2002, the applicant described these structures and referred the staff to drawing MC-1003-1, which had been provided to the staff previously. Drawing MC-1003-1 shows the general arrangement of these buildings. The applicant indicated that the following components of the turbine buildings and service building are subject to an AMR—anchorage; cable tray and conduit and their supports; checkered plate; electrical and instrument panels and their enclosures; embedments; equipment component supports; equipment pads; expansion anchors; flood, pressure and specialty doors; flood curbs; foundations; foundation caissons (McGuire only); hatches; instrument line supports, instrument racks and frames; masonry block walls; pipe supports; reinforced concrete beams, columns, floor slabs, and walls; fire walls; flood seals; roofing; stair, platform, and grating supports; structural steel beams, columns, plates, and trusses. The staff reviewed these structural components and commodities and found that they were listed in Table 3.5-2 and 3.5-3 of the LRA. Some of these components listed in Table 3.5-3 of the LRA are in the category of component supports that will be further reviewed in Section 2.4.3 of this report.

The staff has completed its review of the applicant's submittals and did not find any omissions by the applicant related to scoping the structures. The staff's review also found that all the structural components and commodities in scope were identified as being subject to an AMR because they are passive and perform the applicable intended functions without moving parts or without a change of configuration or properties, and they are not replaced on a qualified life or specified time period.

2.4.2.6.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified the structures and components associated with the turbine building and service building that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 54.21(a)(1), respectively.

### *2.4.2.7 Unit Vent Stack*

In Section 2.4.2.7, "Unit Vent Stack," of the LRA, the applicant described the unit vent stack and identified the structure and components that are within the scope of license renewal and subject to an AMR.

#### 2.4.2.7.1 Technical Information in the Application

At both McGuire and Catawba, the unit vent stack is a stiffened steel cylindrical shell that is designed as a seismic Category I structure. The cylindrical shell is vertically supported by the roof of the auxiliary building and is laterally attached to the outside cylindrical wall of the reactor building. The unit vent stack at each reactor unit is the primary release point of gases effluent from the plant.

#### 2.4.2.7.2 Staff Evaluation

The staff reviewed Section 2.4.2.7 of the LRA to determine if there is reasonable assurance that the applicant has properly identified the structure and components of the unit vent stack that are in scope and subject to an AMR for license renewal. The unit vent stack performs the intended function to release the filtered and unfiltered gaseous discharges. The inclusion of the structure in the scope of license renewal meets the criteria of 10 CFR54.4(a). The applicant listed "unit vent stack" in Table 3.5-2 of the LRA to represent the components subject to an AMR. The components of the unit vent stack, such as the steel cylindrical shell, vertical and lateral supports, restraints, anchorage, and embedment, are not individually listed in the table. The staff's review found that the unit vent stack is unique and its components and attachments are the integral parts of the unit vent stack. Therefore, the structure, as a whole, is in scope and subject to an AMR for license renewal. Based on this review, the staff found no omissions by the applicant related to identify the structural components subject to an AMR.

#### 2.4.2.7.3 Conclusions

On the basis of this review, the staff concludes that the applicant has properly identified the structure and components of the unit vent stack that were included within the scope of license renewal and subject to an AMR.

### *2.4.2.8 Yard Structures*

In Section 2.4.2.8, "Yard Structures," of the LRA, the applicant described the yard structures and identified the structures and components that are within the scope of license renewal and subject to an AMR.

#### 2.4.2.8.1 Technical Information in the Application

As described in the LRA, the following yard structures at McGuire are within the scope of license renewal—

- reactor makeup water storage tank foundation
- refueling water storage tank foundation
- refueling water storage tank missile wall

- refueling water storage tank pipe trenches
- standby shutdown facility cable trenches
- condenser cooling water intake structure cable trenches

At McGuire, the refueling water storage tank foundation is a poured-in-place reinforced concrete composite structure. The foundation mat is enclosed by a free-standing reinforced concrete wall which is designed to protect the tank from missile strike. The foundation and missile wall are seismic Category I structures. Trenches are provided throughout the plant yard to allow underground routing of cables and piping. The trenches within the scope of license renewal are constructed of reinforced concrete. The covers for the trenches are either made of reinforced concrete or steel checkered plates.

At Catawba, the following yard structures are within the scope of license renewal—

- low pressure service water intake structure
- refueling water storage tank foundation
- refueling water storage tank missile shield
- refueling water storage tank pipe trenches
- standby shutdown facility cable trenches

The Catawba low pressure service water intake structure is a reinforced concrete structure that provides structural support for the components of the conventional low pressure service water system and the fire pumps. As stated in Section 2.4.2.2 of the LRA, the portion of the low pressure service water intake structure that supports the fire pumps are within the scope of license renewal. The refueling water storage tank foundation and missile wall are seismic Category I structures. The tank foundation is a poured-in-place reinforced concrete mat. The tank is enclosed by a free-standing reinforced concrete wall with a height that is capable of containing an assured source of water.

Trenches are provided throughout the Catawba plant site to allow underground routing of cables and piping. The cable and pipe trenches are constructed of reinforced concrete and are covered with either reinforced concrete or checkered plate covers. The yard drainage system is designed to protect all safety-related structures from flooding during a local probable maximum precipitation event. The drainage system consists of catch basin inlets that are connected by corrugated metal pipes to form several networks. The catch basin inlets are constructed of angle iron and grating. The yard drainage system is within the scope of license renewal.

The structural components, component intended functions, and materials of construction listed in Table 3.5-2 of the LRA are applicable to the yard structures.

2.4.2.8.2 Staff Evaluation

The staff reviewed Section 2.4.2.8 of the LRA and each plant's UFSAR to determine if the applicant adequately implemented its methodologies such that there is reasonable assurance that the structures and components comprising the yard structures at each plant site have been properly identified as within the scope of license renewal and subject to an AMR. After completing its initial review, the staff determined that additional information was needed to complete its review.

Table 2.2-1 of the LRA lists the structures for McGuire, and Table 2.2-2 of the LRA lists the structures for Catawba that are within the scope of license renewal. Tables 2.2-3 and 2.2-4 of the LRA list the structures not in scope for the respective plants. The staff reviewed these tables and found that the yard structures, trenches, and drainage systems described in Section 2.4.2.8 of the LRA are included in the scope of license renewal. In Table 3.5-2 of the LRA, the applicant specified that "trenches," and "yard drainage system," and "metal siding" are the components only applicable to the yard structures. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-11, the applicant to identify other components in the table that are also applicable to the yard structures.

In its response dated March 11, 2002, the applicant stated that components listed in Tables 3.5-2 and 3.5-3 of the LRA are applicable to the yard structures unless noted otherwise. For example, equipment pads identified in LRA Table 3.5-2 are the components for all structures, including the yard structures. The foundations for the reactor makeup water storage tank and the refueling water storage tank are listed in the table under the component type "foundations." The refueling water storage tank missile wall is listed in the table under the component type "missile shield." The components of the low pressure service water intake structure at Catawba are all listed in the table as foundations, concrete walls, floor slabs, and anchorage. The corresponding structure at McGuire for these components is the condenser cooling water intake structure. The applicant further clarified that the components for the yard structures identified in Table 3.5-3 of the LRA include cable tray and conduit and their supports, electrical and instrument supports, equipment component supports, pipe supports, stair, platform, and grating supports. Some of these components are noted in the table that they are exposed to the external (yard only) environment.

The staff reviewed the information presented in Section 2.4.2.8 of the LRA and additional information submitted by the applicant in response to the staff's questions. The staff compared the LRA descriptions, and Tables 3.5-2 and 3.5-3 of the LRA, with LRA Tables 2.2-1 through 2.2-4 and available drawings, to verify that the applicant included all the yard structures that meet the scoping criteria of 10 CFR54.4(a), as within the scope of license renewal. As a result of this review, the staff found no omissions by the applicant in scoping the yard structures. The staff also found no omissions for the components and commodities in Tables 3.5-2 and 3.5-3 of the LRA that are applicable to the yard structures for an AMR.

2.4.2.8.3 Conclusions

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has properly identified the structures and components of the yard structures for both plants that were within the scope of license renewal and subject to an AMR in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

### 2.4.3 Component Supports

In Section 2.4.3, "Component Supports," of the LRA, the applicant described the component supports and identified the structures and components that are within the scope of license renewal and subject to an AMR.

*2.4.3.1 Technical Information in the Application*

At both McGuire and Catawba, the component supports are those components that provide support or enclosure for the mechanical and electrical equipment. As stated in Section 2.4.3 of the LRA, the component supports within the scope of license renewal include battery racks, cable tray and conduit, cable tray and conduit supports, control boards, crane rails, enclosures, equipment component supports, HVAC duct supports, instrument line supports, instrument racks and frames, lead shielding supports, new fuel storage racks, pipe supports, stairs, platform and grating supports, and spent fuel storage racks. These support structures are constructed of steel or stainless steel that are located in all of the buildings and structures within the scope of license renewal.

The component supports within the scope of license renewal also include Class I NSSS supports. The Class I NSSS supports include reactor coolant system piping supports, pressurizer upper and lower lateral supports, reactor vessel support, control rod drive seismic structure supports, SG vertical, lower lateral, and upper supports, and reactor coolant pump lateral and vertical support assemblies. These Class I component supports are further described in Section 5.5.14 of the McGuire UFSAR and Section 5.4.14 of the Catawba UFSAR.

The component types, component intended functions, and material of construction for these component supports are listed in Table 3.5-3 of the LRA. The components listed in the table meet the criteria of 10 CFR 54.21(a)(1) for an AMR, because applicable intended functions are performed without moving parts or without a change of configuration or properties, and they are not replaced based on a qualified life or specified time period.

*2.4.3.2 Staff Evaluation*

The staff reviewed Section 2.4.3 of the LRA and each plant's UFSAR to determine if the applicant adequately implemented its methodologies as described in Section 2.1 of the LRA, such that there is reasonable assurance that the component supports have been properly identified as within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 10 CFR 54.21, respectively. After completing its initial review, the staff determined that additional information was needed to complete its review.

During the scoping process for the structures within the scope of license renewal, the applicant identified the passive steel structural components in all buildings and structures that are within the scope of license renewal. Since many of the component supports and enclosures are made from similar materials and are located in the environment common to two or more buildings, the applicant decided to group these general structural components together for an AMR instead of addressing each of them separately in the individual structural evaluation. The applicant classified these general structural components that support or protect most plant mechanical or electrical equipment in the group of "component supports" subject to a specified AMR program. These steel structural components provide support for the safety-related and non-safety related systems, components, and equipment. The applicant lists 21 component types with their intended functions in Table 3.5-3 of the LRA that are subject to an AMR. In addition to the components described in Section 2.4.3 of the LRA, the table lists the equipment component supports in the yard and in the nuclear service water structures, electrical instrument panels, and enclosures. The table also includes the component supports and enclosures that are unique, such as spent fuel and new fuel storage racks, battery racks, control room ceiling, control boards, crane rails and girders, and NSSS supports. These components are subject to the specified AMR program.

Section 2.4.3 of the LRA states that the component supports also include Class 1 NSSS supports. Table 3.5-3 of the LRA lists “Class 1 (NSSS) supports” as the components for the Class 1 NSSS supports subject to an AMR. However, the applicant neither describes the components nor defines the boundaries of the supports that are subject to an AMR. The staff is unable to verify their components for which an AMR is required because these NSSS support assemblies are the Class 1 structures and are different in design. By letter dated January 28, 2002, the staff requested, in RAI 2.4.2-12, the applicant to describe the components of the NSSS support assemblies as well as their boundaries that are within the specified AMR program.

In its response dated March 11, 2002, the applicant stated that the component types for the pressurizer supports, reactor vessel supports, SG supports, and reactor coolant pump supports are identified in Table 3.5-3 of the LRA as the Class 1 (NSSS) supports. Typically, the boundary of a NSSS component support extends from the attachment to the component through the attachment to the support structure. Lugs that are integrally attached to the component are included with the component, not the component support. The concrete floors and walls to which the component supports are anchored are addressed in Table 3.5-1 of the LRA under the reactor building interior structural components. The applicant provided additional detail on the NSSS component supports. The staff reviewed this information and each plant’s UFSAR and available design drawings. The following paragraphs summarize the staff’s evaluation.

RCS pipe supports are generally constructed of a standard support or a structural frame, or combination of the two. A standard support is an assembly generally mass-produced and referred to as a catalogue item. The RCS pipe support frames are constructed of structural steel or tube shapes. The staff verified that these pipe supports are within the scope of license renewal and subject to an AMR.

The pressurizer supports consist of an upper lateral support ring and a lower lateral support frame. The upper lateral support ring is a large frame that encircles the pressurizer and is attached to the embedment anchored to the crane wall and the pressurizer enclosure wall. The lower lateral support is a frame attached to the vertical hangers. The lower lateral support frame attaches to the embedded plates that are anchored to the crane wall and the operating floor slab. The support skirt of the pressurizer is attached to a circular steel frame that is connected to the lateral support frame. The staff verified that all these support components are within the scope of license renewal and subject to an AMR.

The reactor vessel supports are the individual rectangular steel box structures. They are located beneath the two opposing cold leg nozzles and two opposing hot leg nozzles. These supports are constructed from steel plate sections and are anchored to the primary shield wall (lower reactor cavity wall). The staff verified that all the components of the reactor vessel supports are in scope and subject to an AMR for license renewal.

The CRDM seismic support is anchored in place by the seismic supports, including turnbuckles, tie rods, and other components. The tie rods arrangement provides radial and rotational restraints. The seismic support platform employs numerous spacer plates, most of which fit around individual CRDM shafts. The staff verified that the CRDM seismic supports and components are in scope and subject to an AMR for license renewal.

The SG is supported by four vertical pinned-end columns, each attached to two SG support lugs, i.e., a lower lateral support (including compression bumpers) and an upper lateral restraint (including a ring band with compression snubbers). The SG support columns provide vertical support for the SGs. The support columns are attached with simple supports to the embedment, which project into the foundation mat through both the base slab and the steel containment vessel liner plate. The SG lower lateral support is a large frame structure consisting of flanged sections constructed from structural steel plates that encircles the SG. The frame structure is attached to the embedment anchored to either the crane wall or the reactor cavity wall. The SG upper lateral restraint consists of a restraint ring, two snubbers, and two A-frame structures. The snubbers are anchored to the SG enclosure wall. The two A-frames, that limit movement of the restraint ring, are attached to the embedment located in either the crane wall or the SG compartment wall. The staff verified that all the components of the SG support are in scope and subject to an AMR for license renewal, except the snubbers. The staff noted that the snubbers are not in scope because they are active components, but the brackets that attach the snubbers to the ring and to the building are in scope and subject to an AMR for license renewal.

Each of the reactor coolant pump supports consists of three vertical steel columns and a lateral steel frame. The steel columns provide vertical support for the RCP that are attached to the embedment in the foundation mat. The RCP lateral support frame is a steel rigid frame structure anchored to the crane wall. The staff verified that all the components of the RCP supports are within the scope of license renewal and subject to an AMR.

The staff has reviewed the LRA and the applicant's response to RAI 2.4.2-12, related to the component supports, including the Class 1 NSSS supports. The staff previously reviewed the other structures including—auxiliary building, turbine building, condenser cooling water intake structure, standby shutdown facility—which address the component supports and enclosures. The staff determined that the component supports listed in Table 3.5-3 of the LRA are part of the safety-related or non-safety-related systems and components, or are part of the structures in scope that are common to most nuclear power plants. The staff verified that they are all in scope and subject to an AMR for license renewal because they are passive and long-lived and perform intended functions. The staff also determined that the NSSS support boundaries that are in scope include all structural support items between the NSSS components and the containment concrete structure, up to and including integral attachments on the components. All the NSSS support components are subject to an AMR with the exception of snubbers, because they are active and subject to replacement on a qualified life.

Based on its review, the staff did not identify any omissions by the applicant related to scoping and screening of the structures for the component supports (including the Class 1 NSSS supports). The staff also verified that all the structural components within the component supports were identified subject to an AMR with the exception of snubbers, which are active components that are not subject to the AMR in accordance with 10 CFR 54.21(a)(1).

*2.4.3.3 Conclusions*

On the basis of this review, the staff concludes that there is reasonable assurance that the applicant has adequately identified those portions of the structures and components associated with the component supports (including the Class 1 NSSS supports) for both McGuire and Catawba that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

## 2.5 Scoping and Screening Results: Electrical and Instrumentation and Control

The applicant identified electrical and instrumentation and control (I&C) component commodity groups subject to an AMR in Section 2.5, “Scoping and Screening Results: Electrical and Instrumentation and Control,” of the LRA. The staff reviewed this section of the LRA to determine that all electrical component commodity groups [which are subject to an AMR, as required by 10 CFR 54.21(a)(3)] have been identified as required by 10 CFR 54.4(a) and 10 CFR 54.21(a)(i).

### 2.5.1 Technical Information in the Application

The applicant performed screening for electrical/I&C components in accordance with NEI 95-10, Appendix B, which identifies the following passive electrical and I&C component commodity groupings (i.e., groups of components that perform similar intended functions without moving parts or without a change in configuration).

- electrical portions of electrical and I&C penetration assemblies
- high-voltage insulators
- insulated cables and connections for power, instrumentation, and control applications (including plug-in connectors, splices, and terminal blocks)
- phase bus (e.g., isolated-phase bus, nonsegregated-phase bus, bus duct)
- switchyard bus
- transmission conductors
- uninsulated ground conductors

Other electrical and I&C component commodity groups are active.

Based on its review, the applicant determined that the electrical and I&C component commodity groups that are subject to an AMR are non-EQ insulated cables and connections for power, instrumentation, and control applications (including plug-in connectors, splices, and terminal blocks).

### 2.5.2 Staff Evaluation

Section 2.1.1 of the LRA, “Scoping Methodology,” discussed the scoping methodology as it related to the safety-related criteria in accordance with 10 CFR 54.4(a)(1), non-safety-related criteria in accordance with 10 CFR 54.4(a)(2), and the scoping criteria in accordance with 10 CFR 54.4(a)(3). Following the determination of the SSCs within the scope of license renewal, the applicant implemented a process for determining which SCs, among those SSCs that were determined to be within scope of renewal, would be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

For scoping and screening of electrical and I&C systems, the applicant used the plant spaces approach, which provides efficiencies in AMR of electrical equipment located within the same plant space environment. Under this approach, the applicant identified all passive long-lived electrical equipment within a specified plant space as subject to an AMR, regardless of whether these components perform any intended functions. In the subsequent AMR, the applicant would evaluate the environment of the space to determine the appropriate aging management activities for the components.

*2.5.2.1 Identification of Passive Components*

From the group of components consisting of all electrical components, the applicant identified the following electrical and I&C component commodity groups as passive—

- electrical portion of electrical, instrumentation, and control penetration assemblies
- high-voltage insulators
- insulated cables and connections for power, instrumentation, and control applications (including plg-in connectors, splices, and terminal blocks)
- phase bus (e.g., isolated-phase bus, nonsegregated-phase bus, bus duct)
- switchyard bus
- transmission conductors
- uninsulated ground conductors

Passive components (for which aging degradation is not readily monitored) are those that perform an intended function without moving parts or without a change in configuration or properties. As examples of passive components, 10 CFR 54.21(a)(1)(i) conveys that electrical components meeting this passive definition as including, but not limited to, electrical penetrations, cables, and connections; and as excluding, but not limited to, motors, diesel generators, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies.

The staff reviewed the above identified component commodity groups to verify that the applicant did not omit any passive component commodity groups and that they meet the above-defined passive screening criteria and/or examples conveyed by 10 CFR 54.21(a)(1)(i). The staff concluded that the above identified component commodity groups are consistent with the examples of passive components conveyed by 10 CFR 54.21(a)(1)(i), and are therefore considered acceptable. In addition, these component commodity groups were found to be the same as the passive determinations described in NEI-95-10 (Revision 3), Appendix B, for component commodity groups in the electrical category. The staff has reviewed these NEI determinations and concluded (1) that each component identified performs its intended function without moving parts or without a change in configuration or properties, and its aging degradation is not readily monitored and (2) that these components acceptably identify passive components pursuant to 10 CFR 54.21(a)(1)(i). Therefore, the staff agrees that the above-identified subgroup of electrical components represents the passive electrical components (i.e., component commodity groups) that would be required to be included in an AMR if they also meet scoping and long-lived screening criteria.

*2.5.2.2 Identification of Components Not Within the Scope of License Renewal*

From the above-identified subgroup of passive electrical and I&C component commodity groups, the applicant in the LRA identified the following component commodity groups as being outside the scope of license renewal.

- high-voltage insulators
- phase bus (e.g., isolated-phase bus, nonsegregated-phase bus, bus duct)
- switchyard bus
- transmission conductors
- uninsulated ground conductors

Switchyard systems were found not to meet any of the scoping criteria of 10 CFR 54.4(a). Consequently, the passive electrical component commodity groups of switchyard bus, transmission conductors, and high-voltage insulators (included in switchyard systems) are not within the scope of license renewal.

The unit main power system and nonsegregated-phase bus in the 6.9kV normal auxiliary power system were found not to meet any of the scoping criteria of 10 CFR 54.4(a). Consequently, the passive electrical component commodity groups of phase bus are not within the scope of license renewal.

<u>Uninsulated Ground Conductors</u>: Section 2.5 of the LRA indicates that the passive electrical component commodity groups of uninsulated ground conductors were found not to meet any of the scoping criteria of 10 CFR 54.4(a). Consequently, uninsulated ground conductors were considered outside the scope of license renewal. By letter dated January 17, 2002, the staff requested, in RAI 2.5-3, the applicant to clarify why uninsulated ground conductors that provide safety-related electrical systems with the capability to withstand transient conditions (e.g., electrical faults) do not meet the scoping criteria of 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2). In its response dated March 8, 2002, the applicant stated the following—

> The non-safety-related scoping criterion of 10 CFR 54.4(a)(2) is not a function-based criterion but a failure-based criterion. To further understand this scoping criterion and how a non-safety-related system or component could be within scope, the language of this criterion is expanded in Chapter 6 of the License Renewal Electrical Handbook, EPRI 1003057, (page 6-6) as follows:
>
>> License Renewal Electrical Handbook
>> "A non-safety-related system or component is not in scope (per §54.4(a)(2)) unless its failure would—
>>
>> • cause a loss of the integrity of the reactor coolant pressure boundary,
>>
>> • cause a loss of the capability to shut down the reactor or the capability to maintain it in a safe shutdown condition, or cause a loss of the capability to prevent or mitigate the consequences of accidents that could result in the potential offsite exposure specified in §54.(a)(1)(iii)."
>
> This non-safety-related failure is a single failure as discussed in licensing and station design documents. Single failures are considered as part of the current licensing basis for both McGuire and Catawba. McGuire and Catawba are in conformance with licensing commitments concerning single failure as contained in Section 3.1, "Conformance with General Design Criteria" of their respective UFSARs. Criterion 17 - Electrical Power Systems is excerpted below:

> UFSAR Section 3.1, Conformance with General Design Criteria Criterion 17 - Electrical Power Systems
> "...The onsite electrical power supplies...and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure...."

> Based on conformance with single failure criteria as outlined in both the McGuire and Catawba UFSARs, no uninsulated ground conductor failure would prevent satisfactory accomplishment of any of the safety-related functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii). Uninsulated ground conductors do not meet the non-safety-related scoping criterion of 10 CFR 54.4(a)(2).

Because the plant conforms with single failure criteria, and because operability of the ground conductor has not been credited as part of the design basis analysis for ensuring that there is sufficient independence of redundant systems to meet single failure requirements of Criterion 17 of 10 CFR Part 50, Appendix A, the staff agrees that the uninsulated ground conductors are not within scope because a failure of these components would not prevent satisfactory completion of any of the safety-related functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii).

<u>Offsite System Scoping</u>: Section 2.5 of the LRA indicates that the passive electrical component commodity groups of switchyard bus, transmission conductors, and high-voltage insulators are not within the scope of license renewal because offsite systems (to which these component commodity groups are a part) were found not to meet any of the scoping criteria of 10 CFR 54.4(a). Consequently, offsite systems (and consequently these component commodity groups) were considered outside the scope of license renewal. The staff disagreed with this conclusion.

10 CFR 54.4(a)(3) requires that all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commissions regulations for station blackout (10 CFR 50.63) be included within the scope of license renewal. 10 CFR 50.63 requires that each light-water-cooled power plant licensed to operate be able to withstand and recover from a station blackout of a specified duration. The establishment of this specified duration (or coping) can be based on plant evaluations that follow the guidance in NRC Regulatory Guide 1.155 and NUMARC 87-00. This guidance requires that the plant evaluation consider offsite system characteristics, such as the expected frequency of loss of offsite power, and the probable time needed to recover offsite power. Offsite systems can be relied on in plant evaluations to perform a function that demonstrates compliance with the Commission regulations for station blackout (10 CFR 50.63). Thus, pursuant to 10 CFR 54.4(a)(3), offsite systems should be included within the scope of license renewal to the extent practical.

The staff pursued offsite system scoping generically and held several public meetings on the subject. By letter dated April 1, 2002, the staff issued its position on the license renewal rule (10 CFR 54.4) as it relates to the station blackout rule (10 CFR 50.63). By letter dated January 17, 2002, the staff requested the applicant to clarify why offsite systems (which include switchyard systems, parts of the unit main power system, and nonsegregated-phase bus in the 6.9 kV normal auxiliary power system) are not relied on in safety analyses or plant evaluations to perform a function in the recovery from a station blackout. In addition, the staff requested the applicant to clarify why these offsite system components do not meet the scoping criteria of 10 CFR 54.4(a)(3).

In its response dated March 8, 2002, the applicant indicated that it had re-reviewed plant documents with emphasis on equipment related to the recovery of offsite power. Based on the results of this review, the applicant decided that components that are part of the power path for offsite power from the switchyard are within the scope of license renewal in accordance with the station blackout scoping criterion required by 10 CFR 54.4(a)(3). This power path includes portions of the power path from the unit power circuit breakers (PCBs) in the respective switchyards to the safety-related buses in each plant. The power path includes portions of the switchyard systems, the unit main power system, and the nonsegregated-phase bus in the 6.9 kV normal auxiliary power system of each station.

By letter dated June 26, 2002, the applicant submitted to the staff the results of the AMR it had performed for the passive, long-lived offsite system components that perform a function in the recovery from a station blackout and were identified by the applicant as within the scope of license renewal. Pending completion of the staff's review of this information, this issue was characterized as SER open item 2.5-1.

In its June 26, 2002, letter, the applicant indicated that the following passive component commodity groups (that were originally identified as out of scope) have been identified as being within the scope of license renewal and subject to an AMR—high-voltage insulators, phase bus (e.g., isolated-phase bus, nonsegregated-phase bus, bus duct), switchyard bus, and transmission conductors. In a letter dated October 2, 2002, the applicant clarified its response to SER open item 2.5-1 as follows—

> All insulated cables and connections (power, control and instrumentation applications) installed in the additional areas identified in the SBO open item response were, and still are, in scope as part of a bounding scope. The maximum cable voltage at either station is 13.8kV. The cables in these additional areas are included in the aging management review for insulated cables and connections submitted in the June 2001 License Renewal Application. This June 2001 cable aging management review is a bounding review that included all cables installed in these additional areas and structures (the areas and structures now identified as being within scope).

The applicant also provided, in a letter dated October 28, 2002, a simplified one line diagram of the SBO power recovery path, and further clarified that insulated cables and connections, included as part of the SBO power recovery path, are considered to be part of the larger component commodity group which includes all insulated cables and connections. Cables and connections in the SBO power recovery path were considered by the applicant to be within the scope of license renewal and subject to an AMR.

Based on its review of the information provided in the applicant's letters dated March 8, 2002, and June 26, 2002; information provided during a September 17, 2002, meeting with the applicant (summarized by memorandum dated September 17, 2002); and subsequent correspondence from the applicant dated October 2, 2002, and October 28, 2002, the staff concludes that passive offsite system component commodity groups (i.e., components included as part of switchyard, unit main power, and 6.9kV normal auxiliary power systems) have been identified by the applicant to be within the scope of license renewal. Therefore, open item 2.5-1 is closed. The staff's evaluation of the AMR results, provided by the applicant in its June 26, 2002, letter, is documented in Section 3.6.4 of this SER.

<u>Treatment of Fuse Holders</u>: In a letter dated May 16, 2002, the staff forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists a proposed interim staff guidance

(ISG) document on screening of electrical fuse holders. The ISG stated that fuse holders should be scoped, screened, and subject to an AMR in the same manner as terminal blocks and other types of electrical connections that also meet the criteria specified in 10 CFR 54.4 and 54.21. This position applies only to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered piece-parts of the larger assembly and not subject to an AMR.

The intended functions of a fuse holder are to provide mechanical support for the fuse and to maintain electrical contact with the fuse blades or metal end caps to prevent the disruption of the current path during normal operating conditions when the circuit current is at or below the current rating of the fuse. Like electrical connections, fuse holders perform a primary function of providing electrical connections to specified sections of an electrical circuit to deliver rated voltage, current, or signals. These intended functions of fuse holders meet the criteria of 10 CFR 54.4(a). In addition, these intended functions are performed without moving parts and without a change in configuration or properties as described in 10 CFR 54.21(a)(1)(i). The fuse holders into which fuses are placed are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of copper.

Operating experience as documented in NUREG-1760, “Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants,” indicates that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. The final staff position on this issue is under development. In a letter dater November 13, 2002, the staff requested the applicant to commit to implement, at McGuire and Catawba, the final resolution of the ISG.

In its response to the staff’s request, dated November 18, 2002, the applicant provided the following commitment:

> For McGuire, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by June 12, 2021 (the end of the initial license of McGuire Unit 1).
>
> For Catawba, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by December 6, 2024 (the end of the initial license of Catawba Unit 1).

This commitment was included in a table of commitments submitted by the applicant in a letter dated December 16, 2002. The table of commitments is provided in Appendix D of this SER. The staff found the applicant’s response acceptable because it commits to implement the final resolution of the ISG before the period of extended operation begins at McGuire and Catawba.

*2.5.2.3 Identification of Components that are Passive but Not Long-Lived*

From the above-identified subgroup of passive electrical and I&C component commodity groups, the applicant identified the following component commodity groups as not meeting the long-lived screening criteria—

- electrical portion of electrical, instrumentation, and control penetration assemblies
- insulated cables and connections (power, instrumentation, and control applications; connections include plug-in connectors, splices and terminal blocks) that are included in the McGuire and Catawba 10 CFR 50.49 EQ program

A component that is not replaced either (1) on a specified interval based on the qualified life of the component or (2) periodically in accordance with a specified time period, is deemed to be "long-lived," and therefore subject to an AMR.

Components subject to EQ aging requirements pursuant to 10 CFR 50.49(e)(5) are required to be replaced or refurbished at the end of their designated life. These components, pursuant to 10 CFR 50.49(e)(5), are subject to replacement based on a qualified life or specified time period. The applicant in the LRA conveyed that the above identified components are included in their 10 CFR 50.49 EQ program and subject to aging requirements of 10 CFR 50.49(e)(5). The staff, therefore, agrees that the above-identified components do not meet long-lived screening criteria and are thus not subject to an AMR.

### 2.5.3 Conclusion

Based on its review and satisfactory resolution of SER open item 2.5-1, the staff did not find any omissions and, therefore, concludes that the applicant has identified component commodity groups of the electrical and I&C systems that are within the scope of license renewal pursuant to 10 CFR 54.21(a), and subject to an AMR pursuant to passive screening criterion 10 CFR 54.21(a)(1)(i) and the long-lived screening criterion 10 CFR 54.21(a)(1)(ii).

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# 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<br>Refueling Water<br>Spent Fuel Pool Cooling | EPRI Report TR-105714-R4 “PER Primary Water Chemistry Guidelines” |
| Closed Cooling Water | Component Cooling System<br>Recirculated Cooling Water System | EPRI Report TR-107396 “Closed Cooling Water Chemistry Guidelines” |
| Treated Water | Demineralized Water<br>Feedwater<br>SG Wet Lay-up Recirculation | EPRI Report TR-102134-R5 “PER Secondary Water Chemistry Guidelines” |
| Fuel Oil | Diesel Generator Fuel Oil<br>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:

> <u>Category E-B</u>
> 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.
>
> <u>Category E-D</u>
> 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 <u>NOT</u> excluded from the Inservice Inspection Plan - IWE for McGuire and Catawba.
>
> <u>Category E-G</u>
> 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:

> <u>McGuire Operating Experience</u>
> 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

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[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

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[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<br><br>Cracking | Chemistry Control AMP |
| Associated Attachment Welds for the Thermal Sleeves | Note 2 | Nickel-based Alloy Weld | Borated Water | Cracking | Chemistry Control AMP<br><br>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).

<u>Pressurizer Spray Head Examination</u>

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

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[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.

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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:

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[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).

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[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 ($\Delta RT_{NDT}$ 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 $\Delta RT_{NDT}$ 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 ($\Delta RT_{NDT}$ 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 $\Delta RT_{NDT}$ value that is less than 100 °F. For a material with a projected $\Delta RT_{NDT}$ 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).

<u>Reactor Coolant System Operational Leakage Monitoring Program</u>

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 $^{o}$C (600 $^{o}$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

3.1.4.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant identifies the following AMPs applicable to the McGuire and Catawba RV internals:

- Chemistry Control Program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Internals Inspection Program

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the RV internals 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). Table 3.1-1 narrows in scope which of these programs will be used to manage the aging effects identified in the table as being applicable to the specific RV internal components requiring AMRs.

The applicant did not specifically identify any TLAA in Section 3.1.1 of the LRA that is applicable to RV internals. However, Section 4.3 of the LRA includes a TLAA for metal fatigue of ASME Class 1 components that applies to RV internals.

*3.1.4.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section 3.1.1 (including 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 RV internals 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 states that the intended functions of the RV internals are to provide support and orientation of the reactor core (i.e., the fuel assemblies); provide support, orientation, guidance, and protection of the control rod assemblies; provide a passageway for the distribution of the reactor coolant flow to the reactor core; provide a passageway for support, guidance, and protection for the incore instrumentation; provide secondary core support for limiting the downward displacement of the core support structure in the event of a postulated failure of the core barrel; and provide neutron shielding of the reactor vessel and provide support for vessel material test specimens.

3.1.4.2.1 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 internals 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.

LRA Table 3.1-1 lists the RV internals, intended functions, materials of construction, operating environment, aging effects, and aging management programs and activities credited to manage the identified aging effects for each RV internal component category. A review of the information in this table indicates that all applicable RV internals are identified, except for the BMI instrumentation tubes. The applicant has grouped the BMI instrumentation tubes with the RV and CRDM pressure boundary components.

The materials of construction for the RV internals are stainless steel, including CASS, and nickel-based alloy. All surfaces of RV internals are exposed to borated water. Table 3.1-1 of the LRA identifies that the following aging effects require aging management:

- cracking of stainless steel (including CASS) and nickel-based alloy components in a borated water environment
- loss of material from stainless steel (including CASS) and nickel-based alloy components in a borated water environment
- reduction in fracture toughness of stainless steel and cast austenitic stainless steel in a borated water environment
- loss of preload of stainless steel bolting and hold down springs in a borated water environment
- dimensional changes of stainless steel components in a borated water environment due to void swelling

As described in topical report WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," and the associated staff FSER, the aging mechanisms potentially applicable to the RV internals are neutron irradiation embrittlement, stress corrosion cracking (SCC), irradiation-assisted stress corrosion cracking (IASCC), erosion and corrosion processes, creep/irradiation creep, stress relaxation, wear, thermal aging, fatigue, and void swelling. However, the RV internals at McGuire and Catawba are made from materials that are resistant to loss of material by general corrosion and flow-assisted corrosion (erosion/corrosion). The RV internals for the McGuire and Catawba units also are not exposed to a high enough temperature (>540 $^{o}$C or 1000 $^{o}$F) where creep-induced degradation would become an aging concern for the internals.

Cracking of RV internals due to either SCC or IASCC is an applicable aging effect for RV internals. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for bolting, given the potential for occluded environmental conditions in crevice areas. IASCC is SCC that is enhanced by exposure of the materials to ionizing radiation. Cracking of the RV internals may also occur from thermal fatigue. The applicant addresses thermal fatigue of the RV internals in Section 4.3 of the LRA, and the staff's evaluation of thermal fatigue of the RV internals is documented in Section 4.3 of this SER. In LRA Table 3.1-1, the applicant has identified cracking as an applicable aging effect for all RV internals. This is acceptable to the staff because the applicant has accounted for cracking of the RV internals that could be induced by either SCC, IASCC, or thermal fatigue.

Loss of material from wear of RV internals occurs due to relative motion between the interfaces and mating surfaces of components caused by flow-induced vibration during plant operation; differential thermal expansion and contraction movements during plant heatup and cooldown; and changes in power operating cycles. The severity of the wear depends on the frequency of motion, duration, and component loadings. Although the applicant did not discuss wear in LRA Section 3.1, the applicant did identify loss of material as an applicable aging effect for all RV internals in Table 3.1-1 of the application. This is acceptable to the staff because it agrees with

NUREG-1800 that loss of material is an applicable effect for the RV internals of PWRs, and because it specifically accounts for loss of material that could be induced by wear.

Stress relaxation may be defined as the unloading of preloaded components under conditions of long-term exposure of RV internals materials to high constant strain, elevated temperature, and/or neutron irradiation. Loss of preload due to stress relaxation is an applicable aging effect for those RV internals with substantial preload (e.g., hold down spring, bolted connections). A loss of preload in these components could result in higher cyclic and transient loads and a loss of function. The combination of bolt stress relaxation, changes in transient and high-cycle vibration of the RV internals, and the effects of increased RV internals fatigue susceptibility may be significant for the license renewal period. The RV internals susceptible to loss of preload due to stress relaxation are the upper and lower support column bolts, the hold down spring, and the clevis insert bolts. In LRA Table 3.1-1, the applicant has identified loss of preload as an applicable aging effect for the upper and lower support column bolts and the hold down spring, but not for the clevis insert fasteners.

By letter dated January 30, 2002, the staff informed the applicant that WCAP-14577, "License Renewal Evaluation: Aging Management for Reactor Internals," specifically identifies that loss of preload is an applicable effect for the clevis insert bolts (fasteners) during normal operations and requested (in RAI 3.1.4-4) the applicant to address this information from the WCAP. In its response to RAI 3.1.4-4, dated April 15, 2002, the applicant stated that loss of preload could be an applicable effect for the McGuire and Catawba clevis insert fasteners, and that the effects of loss of preload in the clevis insert fasteners would manifest itself as loose, cracked, or missing clevis inserts bolts (fasteners). The applicant stated that, since a VT-3 examination may not be sufficient to detect cracking, it will perform a VT-1 examination of the clevis insert fasteners each inspection interval. In the response to RAI 3.1.4-4, the applicant provided a supplemental AMR Table for the clevis insert fasteners that adds loss of preload as an applicable effect for the clevis insert fasteners (in addition to cracking and loss of material). The staff's evaluation of the applicant's proposed augmented inspection activities for the clevis insert fasteners is given in Section 3.1.4.2.2 of this SER.

The applicant's response to RAI 3.1.4-4, and supplemental AMR for the clevis insert fasteners, identifies that loss of preload is an additional aging effect for the RV internals upper and lower support column bolts, hold down spring, and clevis insert fasteners. This is acceptable to the staff because it accounts for stress relaxation, which is a contributing cause of loss of preload in these components, and because it agrees with Table 3.1-1 of NUREG-1800 in that loss of preload is an applicable aging effect for bolted, fastened, or spring loaded RV internals in PWR-designed reactors.

In LRA Section 3.1.1, the applicant states that reduction in fracture toughness due to thermal embrittlement can be an aging effect for certain types of CASS components in locations where temperatures continuously exceed 250 °C (482 °F). The staff, in a letter dated May 19, 2000, clarified that not all CASS materials are subject to thermal embrittlement and provided certain criteria for identifying CASS components susceptible to thermal embrittlement. In this letter, the staff specifically identified that centrifugally cast CASS materials are not subject to thermal aging in the same manner as are statically cast CASS materials. Neutron irradiation of CASS materials may also contribute to a loss of fracture toughness in the materials, if the exposure to the neutrons is above a certain threshold. The applicant stated that it performed an analysis of all CASS material components in the RCS. As a result of this analysis, the applicant identified that reduction in fracture toughness is an applicable aging effect for all RV internals made out of CASS. This is acceptable to the staff because it accounts for the effect of ionizing irradiation of the fracture toughness properties of CASS RV internals, and because it agrees with Table 3.1-1 of NUREG-1800 in that loss of fracture toughness is an applicable aging effect for all PWR RV internals made from CASS.

The RCCA guide tube support pins used in Westinghouse RV internals have a history of degradation. Several Westinghouse plants experienced cracking of guide tube support pins manufactured from Alloy X-750. The cracking of the Alloy X-750 material was attributed to the combination of high stress and undesirable microstructure. In WCAP-14577, Rev. 1-A, Westinghouse stated that cracking of the support pins will not result in a significant misalignment, and the intended function will be maintained. However, these pins are being replaced at a number of plants. Replacement is considered to be a sound maintenance practice to preclude degradation when industry experience indicates that such degradation has been observed. In Table 3.1-1 of the LRA, the applicant does not list the RCCA guide tube support pins as a separate entry. By letter dated January 28, 2002, the staff requested, in RAI 3.1.4-1, clarification of the aging management for these components at McGuire and Catawba. In its response dated April 15, 2002, the applicant indicated that the guide tube support pins, "split pins," are part of the guide tube assemblies in Table 3.1-1 (page 3.1-16, row 3) of the LRA. The applicant has stated that since the guide tube support pins (split pins) are fabricated from Type 316 cold worked stainless steel, they have the same aging effects applicable to the other stainless steel components in the guide tube assemblies. This is acceptable to the staff because it agrees with Table 3.1-1 of NUREG-1800 in that loss of material and cracking are both applicable effects for these components.

In LRA Table 3.1-1, the applicant did not identify reduction in fracture toughness due to irradiation as one of the applicable aging effects for the lower support plate (forging) and lower core support column reactor vessel internals. These materials are fabricated from austenitic stainless steel. In NUREG/CR-6048, Oakridge National Laboratory, on behalf of the NRC, has used $5 \times 10^{20}$ neutrons/cm$^2$ (E > 1 MeV) as the threshold for loss of fracture toughness due to radiation embrittlement in Type 304 austenitic stainless steel materials. To substantiate that loss of fracture toughness is not an applicable effect for these components, the staff issued RAI 3.1.4-2, by letter dated January 28, 2002, and requested that the applicant confirm that accumulated neutron fluence (E > 1 MeV) for these components, during the period of extended operation, would be lower than this threshold for radiation-induced embrittlement. In the RAI, the staff also indicated that, if the fluence levels for the lower support plate (forging) and lower core support columns were projected to be greater than $5 \times 10^{20}$ neutrons/cm$^2$ (E > 1 MeV), the applicant should discuss how reduction in fracture toughness in these components would be managed during the proposed extended periods of operation.

In its response to RAI 3.1.4-2, dated April 15, 2002, the applicant stated that the maximum projected fluence for the lower support forging at 54 ESPY is approximately $5 \times 10^{18}$ neutrons/cm$^2$ (E > 1 MeV), which is less than the threshold fluence value established by the staff. The applicant stated that the lower support forging is not expected to experience reduction of fracture toughness as a result of neutron embrittlement. In contrast, the applicant also stated that the maximum projected fluence at the very top of the lower core support columns, the area of the columns closest to the core and subject to the highest neutron fluence, is approximately $5 \times 10^{21}$ neutrons/cm$^2$ (E > 1 MeV), and that, because the projected fluence at the top portion of the support columns is projected to exceed the threshold $5 \times 10^{20}$ neutrons/cm$^2$

(E > 1 MeV), reduction in fracture toughness should be included as an aging effect for the lower core support columns. The applicant also stated that this aging effect will be managed by the RV Internals Inspection Program (Section B.3.27 of LRA Appendix B). On the basis of this evaluation and in response to RAI 3.1.4-2, the applicant provided a supplemental AMR for the lower core support columns that added reduction of fracture toughness as an applicable aging effect for the lower core support columns. This is acceptable to the staff because it is in agreement with Table 3.1-1 of NUREG-1800 in that loss of fracture toughness due to neutron irradiation is an applicable effect for RV internals within the fuel zone region of the reactor (i.e., within regions of the reactor that amass high neutron fluence dose rates).

Void swelling is defined as a gradual increase in dimensions of the RV internals. Under reactor internals irradiation conditions, helium is generated as a nuclear transmutation reaction product. At sufficiently high temperatures, helium bubbles expand to a critical diameter and coalesce (unite) into larger bubbles. These bubbles create void areas (gaps) in the materials and may result in the swelling of the material. Swelling changes the dimensions of the material and may affect the ability of the particular RV internal component to perform its intended functions. Although void swelling has not been observed to date, the staff is concerned that void swelling may become significant during the period of extended operation. Until industry has developed sufficient data to demonstrate that void swelling is not a significant aging mechanism, the staff believes that void swelling should be considered significant, and applicants for license renewal should describe their aging management plan to address void swelling. In LRA Table 3.1-1, the applicant has identified change in dimension as an applicable aging effect for some of the RV internals, presumably those exposed to the highest neutron fluence. By letter dated January 28, 2002, the staff requested, in RAI 3.1.4-3, additional information concerning the criteria applied to establish which RV internals are susceptible to change in dimension due to void swelling.

In its response to RAI 3.1.4-3, dated April 15, 2002, the applicant stated that uncertainty currently exists relative to the prediction of void swelling in PWR conditions. This uncertainty is based on the fact that existing swelling data have been obtained from materials that were not irradiated in a PWR environment. Void swelling is a complex function of neutron flux, neutron fluence, operating temperature, operating stress, material composition, and material fabrication process. However, the key environmental factors influencing void swelling are cumulative radiation dose and temperature.

At present, data are not available to ascertain a specific threshold for the onset of void swelling in solution annealed Type 304 stainless steel in a PWR environment. However, the onset of void swelling in solution annealed and 10, 20, 30 percent cold worked Type 304 stainless steel exposed to a breeder reactor environment is available and is estimated to start at fluence levels of approximately 4 to 8 x $10^{22}$ neutrons/cm$^2$ (E > 1 MeV) at a temperature of 440 °C (824 °F). (Effects of Radiation on Materials, ASTM STP725, Comparison of High-Fluence Swelling Behavior of Austenitic Stainless Steels, Page 484.) PWRs operate at approximately 315 °C (599 °F) well below 440 °C (824 °F). Duke conservatively estimated all reactor vessel internal components that receive greater than $10^{22}$ neutrons/cm$^2$ (E >1 MeV) as having the potential for void swelling as an aging effect.

At the time this LRA was being prepared, the reactor vessel internals locations identified in Table 3.1-1 as susceptible to dimensional changes were considered to be the limiting locations. However, based on a fluence analysis that has been recently completed, several of these locations are no longer considered to be limiting. The locations that are no longer considered to be limiting are the core barrel flange, outlet nozzles, neutron panels, and irradiation and specimen holder fasteners. These locations do not fall within the range of fluence identified above and should not have dimensional change due to void swelling as an aging effect during the license renewal period.

Understanding the factors discussed above requires further assessment of the operating conditions experienced in PWRs and how stainless steel responds under these conditions. Duke is currently participating in industry programs, which are addressing the significance of void swelling. These programs are addressing both the physical phenomenon of void swelling, as well as the safety significance. As understanding of the phenomenon of void swelling increases, Duke will adjust programmatic management of the RV internals, as needed, to ensure that there remains reasonable assurance that there is not a loss of intended function during the period of extended operation due to void swelling. The RV internals inspection (Section B.3.27 of LRA Appendix B) identifies the applicant’s committed actions with respect to identification and inspection of the RV internals most susceptible (limiting) to void swelling, including participation in the industry’s programs to address this issue. The staff’s evaluation of this AMP is documented in Section 3.1.4.2.2 of this SER.

Westinghouse WCAP-14577, Rev. 1-A, “License Renewal Evaluation: Aging Management for Reactor Internals,” defines fatigue as the structural deterioration that results from repeated stress/strain cycles due to fluctuating loads and temperatures. Following repeated cyclic loading of sufficient magnitude, damage can accumulate, initiating a crack in highly affected locations. As described in the topical report, the design bases for many Westinghouse RV internals include explicit fatigue evaluations. This is the case not only for RV internals designed to the ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, 1974 Edition, but also for RV internals designed using the ASME Code as a guide, prior to incorporation of Subsection NG in the code. The McGuire and Catawba RV internals were designed before the incorporation of Subsection NG in the 1974 ASME Code. LRA Section 4.3 describes the applicant’s TLAA for metal fatigue. The staff’s evaluation of the TLAA for metal fatigue is given in Section 4.3 of this SER.

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 internals.

3.1.4.2.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant credits the following AMPs to manage aging of the RV internals:

- Chemistry Control Program
- ISI Plan
- Alloy 600 Aging Management Review
- Reactor Vessel Internals Inspection Program

In Table 3.1-1 of the LRA, the applicant lists all RV internals 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 the 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 in McGuire and Catawba RV internal 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 staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for RV internals. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The ISI plan (Section B.3.20 of LRA Appendix B) manages 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, 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 staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the reactor vessel internals. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

In its response to RAI 3.1.4-4, the applicant identified that loss of preload was an applicable aging effect for the RV internals clevis insert fasteners, and stated that the ISI plan will be augmented to manage loss of preload in the RV internals clevis insert fasteners. Therefore, the applicant stated that the following will be added to both Section 18.2.16 of the FSAR supplement for the McGuire station and Section 18.2.15 of the FSAR supplement for the Catawba station: "A VT-1 examination of the reactor vessel internal clevis insert fasteners will be performed in lieu of the VT-3 examination currently required by ASME Section XI."

This statement supplements the monitoring and trending program attribute for the ISI plan (Section B.3.20 of Appendix B to the LRA). The staff concludes that the proposal to use a VT-1 examination, in lieu of a VT-3 examination of the clevis insert fasteners once an ISI interval, is acceptable because the requirements imposed by ASME Section XI for performing VT-1 type visual examinations are more conservative than those imposed by ASME Section XI for performing VT-3 type visual examinations. The applicant's method for inspecting the clevis insert fasteners during the extended periods of operation is therefore acceptable to the staff.

As it relates to RV internals, the purpose of the Alloy 600 Aging Management Review, as described in Section B.3.1 of LRA Appendix B, is to ensure that nickel-based alloy locations are adequately inspected for cracking due to PWSCC by the ISI plan and the reactor vessel internals inspection. This review will be completed after issuance of a renewed operating license, but before June 12, 2021, for McGuire, and before December 6, 2024, for Catawba. The staff has evaluated this AMP and found it to be acceptable for managing the aging effects identified for RV internals. The staff's evaluation of the Alloy 600 aging management review is documented in Section 3.1.2.2.2 of this SER.

The Reactor Vessel Internals Inspection, as described in Section B.3.27 of LRA Appendix B, manages cracking due to IASCC and SCC, reduction in fracture toughness due to irradiation and thermal embrittlement, dimensional changes due to void swelling, and loss of preload due to stress relaxation. The staff's evaluation of this program follows.

Reactor Vessel (RV) Internals Inspection

The applicant describes the Reactor Vessel (RV) Internals Inspection program in Section B.3.27 of LRA Appendix B. The applicant credits this AMP to manage specific RV internals aging effects for McGuire and Catawba. 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 applicable RV internals during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The purpose of the RV Internals Inspection program is to monitor the condition of RV internals in order to assure that the applicable aging effects will not result in loss of their intended functions during the period of extended operation. The applicant identifies three groups of stainless steel RV internals within the scope of this AMP: (1) plates, forgings, and welds, (2) baffle-to-baffle, baffle-to-former, and barrel-to-former bolting, and (3) items fabricated from CASS. The applicant stated that different aging effects will affect various RV internal parts. The aging effects addressed by this AMP are: (1) cracking, (2) loss of preload, (3) reduction in fracture toughness, and (4) dimensional changes. The applicant stated that this AMP will supplement the ISI plan to assure that aging effects potentially requiring additional management will not result in loss of intended functions of the RV internals during the period of extended operation.

Table 3.1-1 of the LRA identifies that the RV internals that will be managed by AMP B.3.27 are CASS upper support column (base, conduit support, thermocouple stop(U1)); upper support column bolts; upper core plate and its alignment pins; fuel alignment pins; CASS 15x15 and 17x17 guide tube assembly; CASS UHI flow columns (base); core barrel, flange and outlet nozzles, neutron panels, irradiation specimen holder fasteners; baffle and former plates; baffle bolts; lower core plate, fuel alignment pins, lower support column bolts; and CASS BMI (upper end, cruciform).

The applicant credited the McGuire/Catawba RV Internals Inspection for managing aging effects in the McGuire/Catawba RV internal components. The staff evaluated the RV Internals Inspection on the following seven program 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 RV Internals Inspection is documented in Section 3.0.4 of this SER.

[Program Scope] The applicant stated that the scope of this AMP consists of three groups of stainless steel RV internals: (1) items comprised of plates, forgings, and welds, (2) bolting (baffle-to-baffle, baffle-to-former, and barrel-to-former), and (3) items fabricated from CASS. Note that the applicant has proposed to use an augmented ISI plan VT-1 examination as the method for managing loss of preload in the clevis insert fasteners in lieu of the RV internals inspection. The staff's evaluation of the augmented ISI examination method for managing loss of preload in the clevis insert fasteners is given in Section 3.1.4.2.2 of this SER. The staff concludes that the applicant's scope for the RV Internals Inspection program identifies the appropriate RV internal components that need aging management by the program.

[Preventive Actions] The applicant stated that there are no preventive/mitigative actions associated with this program, nor did the staff identify a need for such. The RV Internals Inspection program is a surveillance monitoring program and, as such, is not designed to prevent or mitigate the aging effects for the RV internal components prior to their occurrence. Since the RV internals inspection is not a preventive or mitigative aging management program, the staff concludes that the preventive actions program attribute for the RV Internals Inspection is acceptable.

[Parameters Monitored or Inspected] The program requires the applicant to perform visual inspections of the RV internals components for the purpose of detecting loss of material due to wear or cracking initiated by fatigue, SCC or IASCC. Visual inspections will also be performed to detect dimensional changes induced by void swelling. Volumetric inspection of bolting is performed to detect IASCC. The RV Internals Inspection requires the applicant to inspect CASS or highly irradiated stainless steel RV internals components for cracks to ensure that the components will not fail catastrophically as a result of fast fracture. The staff concludes that the [Parameters Monitored or Inspected] attribute for the RV Internals Inspection is acceptable because the program directly monitors for flaws (cracking and loss of material) that may occur in the RV internal components and because the program indirectly monitors for materials and mechanical property changes (i.e., for materials/mechanical property-related aging effects of loss of fracture toughness, void swelling, and loss of preload) that may occur in the internals. In the case of the later, the program accomplishes this by ensuring the cracks are detected prior to growth above a limiting size, by monitoring for dimensional changes in RV internal components, and by monitoring for loose or displaced RV internal components, respectively.

[Detection of Aging Effects] The applicant stated that the RV Internals Inspection program uses visual and volumetric inspection methods to monitor for flaws (cracking and loss of material) in the RV internal components. The program also indirectly monitors for materials and mechanical property changes (i.e., for materials/mechanical property-related aging effects of loss of fracture toughness, void swelling, and loss of preload) by ensuring the cracks are detected prior to growth above a limiting size, by monitoring for dimensional changes in RV internal components, and by monitoring for loose or displaced RV internal components. In accordance with the ISI plan, ISI Examination Category B-N-3, for removable core support structures, is directly applicable to the RV internals. This requires visual VT-3 examination of all accessible parts of the RV internals. Cracks initiated by stress corrosion cracking or fatigue will start off very small and will grow over time. VT-3 visual examinations may not be adequate for detecting cracks before they reach the critical flaw size. The monitoring and trending section of this program, which describes the inspection activities for various types of RV internals, indicates that a visual inspection will be performed on components fabricated from plates, forgings and welds to detect the effects of cracking. By letter dated January 30, 2002, the staff requested, in RAI B.3.27-2, the applicant to indicate which visual inspection method (VT-1, VT-2 or VT-3) will be used so that the staff can determine if the visual inspection activities will be capable of detecting cracks before a critical flaw size is reached, and that if VT-3 is proposed as the inspection method, to justify the use of this method for identifying small cracks, or describe enhancements planned to augment this inspection activity.

In its response to RAI B.3.27-2 dated April 15, 2002, the applicant stated that the reactor vessel internals inspection is a program that is completely separate from the ISI Plan. As described in Section B.3.27 of the LRA, the RV internals inspection is being developed to supplement the ISI Plan and is separate from the VT-3 visual examinations currently required by examination category B-N-3. The applicant also stated that the RV Internals Inspection includes several inspections and examinations. The applicant stated that items comprised of plates, forgings, and welds that will be visually inspected, the critical crack size will be determined by analysis and the acceptance criteria for all aging effects will be developed prior to the inspection. The applicant stated that the visual inspection method will be sufficient to detect the critical crack size determined by analysis.

For inspections of baffle bolts, the applicant stated it will perform volumetric examinations to detect whether cracking has occurred in the bolts. As discussed in the staff's FSER for Westinghouse WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," visual examinations will not detect cracking in these bolts. Industry experience is that the cracks will form under the head of the bolts, which is not accessible for visual examination. In addition, loose parts monitoring and coolant reactivity monitoring are effective only after the aging effects have manifested themselves in a potentially serious way. Therefore, augmented inspections, such as ultrasonic examinations, are proposed to provide effective aging management. This is acceptable since the method will be capable of detecting cracks under the heads of the bolts that would not necessarily be detected by use of visual examination methods.

Neutron embrittlement and thermal aging are two mechanisms that may reduce the fracture toughness for a given material. Reduction in fracture toughness lowers the material's critical crack size, which is a bounding material property for any given material. When cracks exist in a component and grow to sizes larger than the critical crack size for the component's material of fabrication, the cracks are considered to be unstable and will propagate quickly through the component. This phenomenon is referred to by materials and mechanical engineers as crack growth by fast fracture. Cracks that propagate unstably by this phenomenon may lead to catastrophic failure of the component. CASS components are known to be particularly susceptible to reduction in fracture toughness as a result of thermal aging; neutron embrittlement of CASS internals may enhance this effect. When this occurs, a CASS component's tolerance to withstand the presence of existing flaws (cracks) is significantly reduced. Thus, while the RV Internals Inspection will not be capable of detecting the critical crack size for the RV internal components made from CASS materials (i.e., because the critical crack size is a material property, not an actual crack or flaw in the material), the examination is designed to detect potential cracks in the RV internals prior to their growing to a size greater than the critical crack size for the material (i.e., critical crack size as reduced as a result of loss of fracture toughness in the material). The applicant has stated that the critical crack size for the CASS RV internals will be established by engineering analysis or calculation, which is the typical method of determining the critical crack size for a given material. Given the applicant's response to RAI B.3.27-2, the applicant must select an examination method that can actually characterize the sizes of potential cracks in the CASS RV internals, and must perform the examination prior to entering the periods of extended operation. When assessed from these technical bases, the applicant's Parameters Monitored or Inspected program attribute is acceptable to the staff.

In electronic correspondence dated June 5-6, 2002 (ADAMS Accession No. ML022200661), the staff asked the applicant to clarify the last sentence of the second paragraph of its response to RAI B.3.27-2. This clarification would be reflected in the Detection of Aging Effects program attribute for this program that is provided in FSAR supplement Chapter, Section 18.2.22. The applicant agreed to make this clarification. By letter dated July 9, 2002, the applicant provided the following:

> Duke confirms that the intent of the last sentence in the second paragraph of its response should be clarified to state:
>
> > The visual inspection method selected for the inspection of RV internal plates, forging, and welds will be sufficient to detect cracks in the components prior to any growth to a size that is greater than the critical crack size (critical crack length) for the material.

Therefore, this issue is resolved.

[Monitoring and Trending] The applicant stated that the RV Internals Inspection includes the following inspection activities: (1) for plates, forgings, and welds, a visual inspection will be performed to detect the effects of cracking by irradiation-assisted stress corrosion cracking enhanced by reduction of fracture toughness by irradiation embrittlement, (2) for baffle bolts, a volumetric inspection will be performed at McGuire 1 to assess cracking, and (3) for items fabricated from CASS, an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items will be performed. The applicant stated that the specific inspection method will depend on the results of these analyses. The applicant stated that the inspections of RV internals at McGuire 1 will be performed in the fifth ISI interval. The decision to perform inspections on McGuire 2, Catawba 1, and Catawba 2, and when to perform such inspections, will depend on an evaluation of the results of the internals inspections performed at Oconee and on McGuire 1.

The applicant also stated that, with respect to dimensional changes due to void swelling, McGuire and Catawba will rely on the results of inspections to be performed at Oconee, and that items comprised of plates, forgings, and welds will be inspected at all three Oconee units to assess the effects of void swelling. Activities are in progress to develop and qualify the inspection method. The applicant stated the results of the Oconee inspections will be used to determine if change in dimensions due to void swelling is a concern for the reactor vessel internals of McGuire 1, McGuire 2, Catawba 1, and Catawba 2, and if additional inspections are necessary. In addition, the applicant stated that should industry data or other evaluations indicate that any of the above inspections can be modified or eliminated, Duke will provide plant-specific justification to demonstrate the basis for the modification or elimination. With regard to monitoring for dimensional changes to due void swelling, this is acceptable to the staff because the Oconee, McGuire, and Catawba plants all have RV internals that are made from martensitic stainless steel materials, austenitic stainless steel materials (including CASS), and nickel-based alloy materials.

By letter dated January 28, 2002, the staff requested, in RAI B.3.27-1, the applicant to clarify the technical validity of this extrapolation, specifically with respect to the similarities and differences pertaining to RV internals design details, materials of construction, reactor power rating and neutron fluence levels, and critical locations where dimensional changes may compromise performance of intended functions. In its response dated April 15, 2002, the applicant stated that currently, limited data from PWR internals are available to properly evaluate the potential for dimensional changes to occur as a result of void swelling. Additional data are needed to properly evaluate the most susceptible locations for inspections. The applicant stated that the Oconee RV Internals Inspections will provide some of that data prior to the McGuire and Catawba license renewal period. Current plans are to inspect the Oconee Unit 1 internals for dimensional changes due to void swelling early in its 20-year period of extended operation or about 2015. Based on the Oconee inspections, as well as results from other internals inspections in the industry, the applicant stated that it will prepare the inspection plan for McGuire 1.

In the Monitoring and Trending attribute for the RV Internals Inspection AMP, the applicant stated that it will perform a volumetric inspection of the McGuire 1 baffle bolts in the fifth ISI interval, and that any detectable cracks are considered to be unacceptable. The applicant also stated that the number of baffle bolts to be inspected and their locations will be determined by analysis. As discussed in the staff's FSER for Westinghouse WCAP-14577, Rev. 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," visual examinations will not detect cracking in these bolts. Industry experience is that the cracks will form under the head of the bolts, which is not accessible for visual examination. In addition, loose parts monitoring and coolant reactivity monitoring are effective only after the aging effects have manifested themselves is a potentially serious way. Therefore, augmented inspections, such as ultrasonic inspections, are needed to be proposed in order to provide effective aging management of the baffle bolts

In RAI 3.27-1, the staff questioned the validity that the results of the baffle bolt examinations at McGuire 1, as well as Oconee Unit 1, would provide an acceptable basis for determining whether to schedule and perform corresponding baffle bolt examinations at McGuire 2 and Catawba 1 and 2. In its response to RAI B.3.27-1, the applicant also provided the following tabular comparison of the reactor power level, materials, operating temperatures, and estimated peak fluence for the Oconee Unit 1, McGuire 1 and 2, and Catawba 1 and 2 baffle plate and bolt locations at the end of 40-year current licensing period:

| Unit | Reactor Power (MWt) | Baffle Former and Plate Material | Baffle Bolt Material | $T_{Hot}$ | $T_{Cold}$ | Estimated Peak Fluence at Baffle Plate and Bolt location (n/cm$^2$, E>1MeV) and year |
|---|---|---|---|---|---|---|
| ONS 1 | 2568 | Type 304 Stainless Steel | Type 304 Stainless Steel | 602.4 | 557.8 | 4.5x10$^{22}$ in 2015* |
| MNS 1 | 3411 | Type 304 Stainless Steel | Type 316 Cold Worked | 613.9 | 556.3 | 5.95x10$^{22}$ in 2021** |
| MNS 2 | 3411 | Type 304 Stainless Steel | Type 316 Cold Worked | 613.9 | 556.3 | 5.8x10$^{22}$ in 2024** |
| CNS1 | 3411 | Type 304 Stainless Steel | Type 316 Cold Worked | 613.9 | 556.3 | 5.7x10$^{22}$ in 2025** |
| CNS2 | 3411 | Type 304 Stainless Steel | Type 316 Cold Worked | 616.7 | 558.3 | 5.8x10$^{22}$ in 2026** |

* Estimated fluence at the time of the first reactor vessel internals inspection at Oconee
** End of 40-year operating license for each unit

On the basis of this comparison, the applicant believes that the estimated peak neutron fluence levels for the McGuire and Catawba baffle bolts at the end of the 40-year operating terms for the units will be similar to the estimated peak neutron fluence levels for the Oconee Unit 1 baffle bolts at the time the Oconee Unit 1 baffle bolts are planned to be inspected (in 2015).

The McGuire, Catawba, and Oconee baffle bolts are all fabricated from austenitic stainless steel materials (Type 304 and Type 316 are both austenitic stainless steel grades of materials) that have similar material properties. Since the McGuire, Catawba, and Oconee baffle bolts are all fabricated from austenitic stainless steel materials, and since the amassed end-of-current-operating-term neutron fluences values for the McGuire and Catawba baffle bolts are expected to be of an order and magnitude similar to that amassed for the Oconee Unit 1 baffle bolts at the time the Oconee Unit 1 baffle bolts will be inspected, the staff concludes that the volumetric examination results of the Oconee Unit 1 and McGuire 1 baffle bolts will be a prime indicator of the condition in the McGuire and Catawba baffle bolts, and thus justifying use of these examinations as the basis for proposing whether examinations of the baffle bolts at McGuire 2 and Catawba 1 and 2 are necessary during the extended periods of operation for the units. Based on these technical considerations, the staff concludes that the applicant has proposed an acceptable basis for scheduling and performing volumetric examinations of the McGuire and Catawba baffle plates, and that the Monitoring and Trending attribute, as it pertains to inspections of the McGuire and Catawba baffle bolts, is therefore acceptable.

For the McGuire and Catawba RV internals made from CASS (i.e., 15X15 and 17X17 guide tube assemblies, BMI tubes, and bases of the UHI flow columns), Duke proposes to use an analytical evaluation as the basis for inspecting these components for cracks. The purpose of the analytical evaluation is to calculate the critical crack size for the components under service loading conditions and service-degraded material properties (i.e., loss of fracture toughness), and to determine the type of NDE needed to detect cracks in the components prior to fast fracture to failure. The applicant proposes to inspect the limiting CASS component at McGuire 1 in the fifth ISI Interval for the plant, and to use the results of the examinations as the basis for proposing whether corresponding examinations are warranted of the CASS RV internals at McGuire 1 and Catawba 1 and 2. The applicant's program and basis for inspecting the CASS

RV internals at McGuire and Catawba is acceptable because the McGuire 1 reactor is expected to be the limiting reactor with respect to neutron exposure, and the results of the inspections of the CASS RV internal components at McGuire 1 will provide a prime indication of the condition these components and form an acceptable basis for determining whether equivalent inspections of the CASS RV internal components at McGuire 2 and Catawba 1 and 2 are necessary.

For the remaining RV internal plates, forgings, welds, and bolts (i.e., core barrel bolts and thermal shield bolts), the applicant has proposed to use examinations performed at Oconee Unit 1 and McGuire 1 as the basis for determining whether additional, corresponding examinations need to be scheduled and performed at McGuire 2 and both Catawba units. By letter dated June 26, 2002, the staff informed the applicant that its program for inspecting these RV internal plates, forgings, welds, and bolts was inconsistent with Duke Power Company's corresponding program for the Oconee Nuclear Station, in which the applicant had proposed to inspect these components in all three Oconee reactor units. In its response dated July 9, 2002, the applicant stated that the justification for using inspections of the McGuire 1 welded plates and forgings, welds, and bolts (i.e., core barrel bolts and thermal shield bolts) was based on a determination that McGuire 1 was the most susceptible unit with regard to aging of RV internals at McGuire and Catawba. The applicant also stated that the decision to use inspections at Oconee 1 as an additional basis for scheduling inspections of the RV internals at McGuire 2 and Catawba 1 and 2 was based on the fact that the RV internals would be inspected prior to the time that any of the McGuire and Catawba units would enter their respective periods of extended operation.

Aging of RV internal components is dependent on a number of factors, including amassed neutron irradiation dose, internal RV operating temperature, and stress and/or pressure loadings. Fabrication factors are also relevant for welded RV internals. The design fabricator of the RVs for McGuire 1 and Catawba 2 is not the same as the design fabricator for McGuire 2 and Catawba 1 or the design fabricator for the reactor units of the Oconee Nuclear Station. The McGuire 1 and Catawba 2 reactor vessels were designed, welded, and fabricated by the Combustion Engineering Corporation. The McGuire 2 and Catawba 1 reactor vessels were designed, welded, and fabricated by the Rotterdam Drydock. The reactor vessels for Oconee Units 1, 2, and 3 were designed, welded, and fabricated by the Babcock and Wilcox Corporation. For welded RV internal components, differences in welding techniques (including differences in the use of preheat methods or post-weld heat treatment methods, differences in welding fabrication methods, variations in the type of weld fluxes used, etc.) that are used to fabricate the vessels and their internal components can create a significant variation as to the susceptibility of the components to crack. The staff concluded that, since the fabricator of the McGuire 1 and Catawba 2 RVs is not the same as the fabricators of the McGuire 2 and Catawba 1 RVs or for the Oconee RVs, some uncertainty exists as to whether the inspections of welded RV internals at Oconee Unit 1 and McGuire 1 will be truly representative of the condition of welded RV internals at McGuire 2 and the Catawba units. The staff's position was that the applicant should schedule inspection of remaining RV internal plates, forgings, welds, and bolts (i.e., core barrel bolts and thermal shield bolts) at all of the McGuire and Catawba reactor units. Therefore, this issue was characterized as SER open item 3.1.4-1(a).

In its response to open item 3.1.4-1(a), dated October 28, 2002, the applicant clarified that all of the RV internals for the McGuire and Catawba units were manufactured by Westinghouse, not by the fabricators of the RVs (i.e., neither Combustion Engineering nor Rotterdam Drydock fabricated the RV internals). In its response, the applicant provided an acceptable design-feature-based argument for concluding that the baffle bolts and plates at McGuire were limiting in regard to the temperatures and fluences the materials would achieve when compared to those in the Catawba units. The applicant also stated that the Catawba RV baffle bolts and plates will have significantly lower potential to develop the aging effects attributed to RV internals (cracking, loss of fracture toughness due to either thermal aging or neutron irradiation embrittlement, or change in dimensions due to void swelling) because they include an original upflow design with cooling holes for the baffle bolts and pressure relief holes in the baffle plates, and because the stresses in the Catawba baffle plates are lower as a result of a lower differential pressure across the baffle plates from the bypass region. The applicant identified that the only significant weld in the McGuire and Catawba RV internals is the circumferential weld in the core barrel and stated that these circumferential welds are projected to have a neutron fluence at EOLE that is lower than the threshold for which irradiation-assisted stress corrosion cracking is to be of concern. The applicant stated that all other welds in the internals are used to capture locking devices. The applicant clarified that the core barrel bolts and thermal shields in the Oconee designs are not applicable to the designs of the RV internals at McGuire and Catawba.

Based on these arguments, the applicant concluded that the McGuire RV internals will be limiting (bounding) in comparison to the corresponding RV internal components at Catawba. Therefore, in its response to open item 3.1.4-1(a), the applicant committed to inspect the RV internals at both McGuire 1 and McGuire 2 during the periods of extended operation for the units, and to use the results of the examinations as the basis for determining whether additional inspections of the RV internals at Catawba 1 and Catawba 2 would be necessary. This commitment was documented in revised descriptions of the Monitoring and Trending program attribute in the FSAR supplements for McGuire and Catawba, which were included in the applicant's open item response. The applicant stated that the RV internals at McGuire 1 will be inspected during the fifth ISI interval for the unit, and the RV internals at McGuire 2 will be inspected during the sixth ISI interval for the unit. Based on this response, the applicant will be performing inspections of the RV internals at five of the seven Duke-owned nuclear reactors, (i.e., at Oconee and McGuire). Since the McGuire RV internals are projected to be limiting in comparison to those at Catawba, the staff concludes that the applicant's proposed inspections for the RV internal core barrel components at McGuire (and at Oconee) will provide an acceptable basis for determining whether age-related degradation is applicable in the corresponding components at Catawba, and for scheduling inspections at Catawba as necessary. This resolves open item 3.1.4-1(a).

[Acceptance Criteria] The applicant stated that the acceptance criteria will be based upon analyses and inspections. The applicant stated that the critical crack size for RV internal plates, forgings, welds, and RV internals made from CASS will be determined by analysis before inspection. For RV internal baffle bolts, any detectable cracking on baffle bolts will be unacceptable. The number of baffle bolts needed to be intact and their locations will be determined by analyses. The applicant did not provide any acceptance criteria for the dimensional change effects that could be induced by void swelling. The applicant's acceptance criteria for the RV Internals Inspection program is incomplete. Therefore, the staff needed additional information regarding the acceptance criteria for the inspections that are proposed to the RV internals. This issue was characterized as SER open item 3.1.4-1(b).

In its response to open item 3.1.4-1(b), dated October 28, 2002, the applicant stated that the Acceptance Criteria attribute of the RV Internals Inspection summary description contained in each station's FSAR supplement will be revised to read as follows (revised text underlined):

> For the items comprised of plates, forgings, and welds, critical crack size will be determined by analysis <u>and submitted for review and approval to the NRC staff</u> prior to the inspection.
>
> For baffle bolts, any detectable crack indication is unacceptable for a particular baffle bolt. The number of baffle bolts needed to be intact and their locations will be determined by analysis.
>
> For items fabricated from CASS, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed <u>and submitted for review and approval to the NRC staff</u> prior to the inspection.
>
> <u>For items subject to dimensional changes due to void swelling, activities are in progress to develop and qualify the inspection method. Acceptance criteria will be developed and submitted for review and approval to the NRC staff prior to the inspection.</u>

The applicant's FSAR supplement summary description for the acceptance criteria for the RV Internals Inspection addresses the need to submit the acceptance criteria established by industry programs for evaluating cracking, loss of fracture toughness, and void swelling in Westinghouse-designed RV internals to the staff for review and approval. This is acceptable to the staff since the industry is currently in the process of establishing what the techniques and acceptance criteria will be for evaluation of these aging effects in Westinghouse-designed RV internals. This resolves SER open item 3.1.4-1(b).

[Operating Experience] The applicant states that the RV Internals Inspection program is a new inspection, and no operating experience exists. The applicant has stated that the RV Internals Inspection proposed for McGuire 1 will be based upon implementation of a similar program for the Oconee Unit 1, and that the decision to examine the RV internals for McGuire 2 and the Catawba reactor units will be based on the combined RV Internals Inspection results for Oconee Unit 1 and McGuire 1. This is acceptable to the staff since there is no current industry experience that could assist the applicant in developing the other program attributes for the RV Internal Inspection.

FSAR Supplement: The staff reviewed LRA Appendix A.1, Section 18.2.22, for McGuire, and LRA Appendix A.2, Section 18.2.21, for Catawba. The staff requested that Duke provide a commitment to update the Detection of Aging Effects program attribute in FSAR supplement Section 18.2.22, "Reactor Vessel Internals Inspection," to reflect the second paragraph in the applicant's response to RAI B.27-2. For tracking purposes, the staff and applicant characterized this issue as SER open item 3.1.4-1(c).

In its response to open item 3.1.4-1(c), dated October 28, 2002, the applicant stated that the FSAR supplements for McGuire and Catawba will be revised to incorporate the following statement:

> The visual inspection method selected for the inspection of RV internal plates, forging, and welds will be sufficient to detect cracks in the components prior to any growth to a size that is greater than the critical crack size (critical crack length) for the material.

The applicant's response to open item 3.1.4-1(c) addresses the issue that, for visual inspections of RV internals at McGuire and Catawba, the applicant will have to implement a visual inspection technique that is capable of detecting surface cracks in the internal components, and is therefore acceptable. This resolves open item 3.1.4-1(c).

In conclusion, the staff reviewed the RV Internals Inspection program. With the resolution of SER open item 3.1.4-1(a), (b), and (c), the staff finds that the implementation of this AMP will provide reasonable assurance that the cracking, loss of preload, dimensional changes, and reduction in fracture toughness of RV internals will be adequately managed, such that the intended function(s) of the RV internals will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.1.4.3 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. With the resolution of SER open item 3.1.4-1(a), (b), and (c), the staff concludes that the applicant has demonstrated that the aging effects associated with the RV internals 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).

### 3.1.5 Steam Generators

Each reactor unit at McGuire and Catawba has four recirculating steam generators (SGs), with one steam generator in each of the four reactor coolant loops. The original Westinghouse (W) models D2 and D3 SGs at Catawba 1, McGuire 1, and McGuire 2 had a number of internal components, including the SG tubes and the tube support plates, that experienced significant degradation during their first few years of service. As a result, Catawba 1, McGuire 1 and McGuire 2 replaced their original SGs with the enhanced model CFR-80 replacement steam generators (RSGs) manufactured by Babcock and Wilcox International (BWI) of Canada in 1996, 1997, and 1998, respectively. The Westinghouse Model D5 SGs at Catawba 2 have not been replaced since they already incorporated many of the enhanced design features of the BWI RSGs and have not experienced the types of degradation observed in Westinghouse D2 and D3 model SGs.

All steam generators at both sites are vertical shell and U-tube evaporators with integral moisture separating equipment. Reactor coolant flows through the inverted U-tubes, entering and leaving through nozzles equipped with stainless steel safe ends located in the hemispherical bottom head of the steam generator. Steam is generated on the shell side of the tubes, and the water-steam mixture flows upward through the tube bundle and into the steam drum section. Centrifugal moisture separators, located above the tube bundle, remove most of the entrained water from the steam. Steam dryers are employed to increase the steam quality before the steam flows upward to the outlet nozzle at the top of the steam generator.

While significant hardware differences exist between the Westinghouse model D5 SGs at Catawba 2 and the BWI model CFR-80 RSGs at Catawba 1, McGuire 1, and McGuire 2, the basic function is essentially identical with one exception in the feedwater delivery system. The Westinghouse model D5 SGs are equipped with preheaters and feedwater flow restrictors with main feedwater delivered just above the tubesheets. Feedwater in the BWI RSGs is distributed by a feedring header, flows directly into a downcomer section, and is mixed with saturated recirculation flow before entering the boiler section. The moisture separators recirculated flow through the annulus formed by the shell and tube bundle wrapper.

*3.1.5.1 Technical Information in the Application*

The applicant described its AMR of the steam generators for license renewal in Section 3.1.1 of the LRA, "Aging Management Review Results Tables," as supplemented by the 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 steam generators will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In accordance with the Catawba and McGuire UFSARs, the steam generators are designed and fabricated in accordance with Section III of the ASME Boiler and Pressure Vessel Code requirements. The SG tubes and plugs are made from corrosion resistant, thermally treated Inconel 690 for the BWI SGs and Inconel 600 for the W SG. The channel head divider plate is nickel-based alloy. The material used for the steam generator shell is made from low-alloy steel. The interior surfaces of the reactor coolant channel heads and nozzles are clad with austenitic stainless steel. The primary nozzles for the BWI SGs are buttered with nickel-based alloy weld material. The primary side of the tubesheets is weld clad with Inconel. The tubes are hydraulically expanded for the full depth of the tubesheets and the ends are seal welded to the tubesheet cladding. Primary nozzles have stainless steel safe ends. The primary manway is made of low-alloy steel clad with stainless steel (W) and nickel-based alloy (BWI). The secondary side components, including the steam drum, manways and their covers, handheld covers, handheld pad, and minor nozzle bosses, are all made from low-alloy steel. Although the LRA states that the RSGs have stainless steel flow restrictors, the applicant informed the staff, in a letter dated November 21, 2002, that the flow restrictors in only the replacement steam generators used in McGuire 1 and 2 and Catawba 1 are made of stainless steel. However, the flow restrictors in the Catawba 2 original steam generators are made of nickel-based alloy.

The SG components on the primary side are exposed to borated reactor water, while on the secondary side, treated water is maintained to minimize corrosion and fouling of the SG heat transfer surfaces. The design temperatures for all SGs are 343.3 °C (650 °F) on the reactor coolant side, and 315.6 °C (600 °F) on the steam side. The design pressure on the reactor coolant side is 17.13MPa (2485 psig), and 8.17 MPa (1185 psig) on the steam side. As stated in Section 3.2 of the Catawba UFSAR, the ASME classification for the secondary side is specified ASME Class 2. However, as stated in Section 5.4.2.3 of the Catawba UFSAR, the current philosophy is to design all pressure retaining parts of the SG, including both the primary and secondary pressure boundaries, to satisfy the criteria specified in Section III of the ASME Code for Class 1 components. This is applicable to RSGs where the analysis set includes not only transients associated with the Class 1 portion of these SGs, but also the transients applicable to certain non-Class 1 portions of these SGs.

3.1.5.1.1 Aging Effects

In LRA Table 3.1-1, the applicant, in accordance with 10 CFR 54.4(a), has identified that maintaining the structural integrity of the reactor pressure boundary is the applicable intended function for most steam generator components. The flow restrictor has an additional thermal-hydraulic intended function involving the provision of throttling, such that the appropriate fluid flow and pressure are supplied by the system.

The following aging effects associated with the SG components that require aging management are also listed in Table 3.1-1 of the LRA:

- loss of material in both borated and treated water for carbon steel, low-alloy steel, stainless steel, and nickel-based alloys
- cracking in carbon steel, low-alloy steel, stainless steel (including cladding materials), and nickel alloy steels (including buttering material)
- loss of preload in low-alloy steel bolting

3.1.5.1.2 Aging Management Programs

In Table 3.1-1 of the LRA, Duke identifies the AMPs for managing aging effects associated with the SG components. The aging effects for the SG components are given as cracking, loss of material, and loss of preload. In this table, the applicant lists the following applicable AMPs and activities for managing these aging effects associated with the SG components:

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review
- Flow-Accelerated Corrosion Program
- Steam Generator Surveillance Program

The applicant concluded that these AMPs will manage the effects of aging, such that the intended function of the SG 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 SG components. However, Section 4.0 of the LRA identifies a TLAA for metal fatigue of ASME Class 1 and Class 2 components that applies to SG components.

*3.1.5.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.1.1 (including Table 3.1-1) of the LRA, 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 SG 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 SG components that are within the scope of the license renewal and identifies the aging effects that require management. The list of components within the scope of license renewal are grouped in accordance with their component types.

3.1.5.2.1 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 SG 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 three aging effects for the steam generator given in Table 3.1-1 of the LRA follow:

- loss of material
- cracking
- loss of preload

In accordance with Section 5.4.2.1.3 of the Catawba UFSAR, additional measures are incorporated in the Westinghouse model D5 design to prevent areas of dry out in the SG and accumulation of sludge in low velocity areas. Modifications to the wrapper have increased water velocities across the tubesheets. A flow distribution baffle is provided which forces the low flow area to the center of the bundle. Increased capacity blowdown pipes have been added to enable continuous blowdown of the SGs at a high volume. Stainless steel tube support plates with broached tube holes minimize tube denting and support plate erosion/corrosion.

Similar design improvements in the RSGs by BWI address a number of SG internal degradation issues. Tube to tubesheet crevice intergranular attack is avoided by selection and control of the tube alloy, as well as development and implementation of the tube expansion tooling and procedures that minimize the crevice at the tubesheet secondary face. Tube to tubesheet crevice and primary side stress corrosion cracking (SCC) is avoided by using tube expansion techniques that minimize residual stresses. The accumulation of crud at the top of the tubesheet (tubesheet sludge piles) may be minimized through achievement of a high circulation ratio, high volume cross flow, high capacity blowdown capability, strict adherence to water chemistry limits, and provision of multiple access ports for sludge lancing. Use of “open-flow” lattice grids and stainless steel in the tube support designs limits corrosion product accumulation at tube supports and reduces denting at tube support locations. Tube vibration fretting wear at lattice grid and U-bend supports is avoided by maintaining optimum tube-to-support contact/clearance, installing U-bend supports, and selecting tube support material that resists wear when in direct contact with Inconel 690 interfaces. U-bend cracking of inner row tubes is avoided by using large minimum radius bends and stress relieving in the tightest bends.

Loss of material due to erosion and corrosion is considered significant for SG components in the secondary side which are fabricated from either carbon steel or low-alloy steel. The primary manway bolted connection is susceptible to boric-acid corrosion when exposed to reactor water leaks. Industry experience also has shown that loss of material can occur in nickel-based alloy SG tubes as a result of pitting/crevice corrosion. Vibration of the SG components may result in loss of material as a result of wear. In Table 3.1-1 of the LRA, the applicant has identified loss of material as an applicable aging effect for all SG components. The staff finds this acceptable because the applicant has conservatively accounted for loss of material in the SG components that could be induced by either flow-assisted corrosion, boric acid corrosion pitting or crevice corrosion, or wear.

Cracking of SG components due SCC, primary water stress corrosion cracking (PWSCC), intergranular stress corrosion cracking (IGSCC), or outside diameter stress corrosion cracking (ODSCC) is an applicable aging effect. SCC results from the synergistic effects of tensile stresses and a corrosive environment on a susceptible material. SCC is a particular concern for the SG tubes, and tube support plates, given the potential for occluded environmental conditions in crevice areas. Welds in the nozzles and their safe ends are also vulnerable to cracking. In Table 3.1-1 of the LRA, the applicant has identified cracking as an applicable aging effect for most SG components. The staff finds this acceptable because the applicant has conservatively accounted for cracking in the SG components that are susceptible to cracking by SCC, PWSCC, IGSCC, or ODSCC. Cracking of SG components by thermal fatigue is addressed in Section 4.3 of the application. The staff's evaluation of cracking of SG components by thermal fatigue is documented in Section 4.3 of this SER.

Stress relaxation in the bolted connections under long-term exposure to high constant strain and elevated temperature may lead to loss of preload. The manway bolts and handhole bolts are susceptible to this aging effect. In Table 3.1-1 of the LRA, the applicant has identified loss of preload as an applicable aging effect for the SG bolting. The staff finds this acceptable because the applicant has conservatively accounted for potential losses of preload in SG bolted connections that could result from stress relaxation.

Catawba 1 completed its first fuel cycle of operation with the replacement SGs (BWR RSGs) in November 1997. Based on industry guidelines for inspection programs for steam generator internals, as described in NUREG/CR-6754, "Review of Industry Responses to NRC Generic Letter 97-06 on Degradation of Steam Generator Internals," the Catawba 1 SG tubing was inspected using eddy current testing, and the upper-bundle and tubesheet regions were inspected either visually or by remote video camera. Similar inspections were also completed on the BWI RSGs at Millstone 2 and Ginna. During SG internal inspections in these three plants after their first service period, it was determined that positioning of the U-bend support components could result in contact between peripheral tubes. The routine ongoing outage cycle inspections (by eddy current test and/or secondary side visual) will monitor the condition over time. No other evidence of degradation in the steam drum, upper bundle (U-bend), and tubesheet regions was observed during these inspections. The applicant has recognized this particular degradation, both in addressing the design improvements associated with BWI RSGs, and in the operating experience for the Steam Generator Surveillance Program in Section B.3.31 of the LRA.

In its April 15, 2002, response to RAI 2.3.1-4, which pertained to the staff's scoping and screening evaluation that is documented in Section 2.3.1.6 of this SER, the applicant added the SG tube supports to the scope of license renewal. The applicant identified that the tube supports for the SGs perform a support function to the pressure boundary function of the SG tubes, and include components such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring and U-bend arch bars, stay rods, tube bundle wrapper, and the tube support plates. The applicant stated that these are fabricated from either alloy steel, stainless steel, or carbon steel, and are exposed to treated water conditions. The applicant stated both loss of material and cracking as applicable effects for the surfaces of tube support components that are exposed to treated water. The staff's evaluations of these materials in treated water conditions have been discussed in previous paragraphs of this section. The staff concludes that the applicant's identification of aging effects for the tube supports is acceptable because the applicant has conservatively accounted for mechanisms that could lead to loss of material or cracking in these components, as discussed in the previous paragraphs in this section.

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 SG components.

3.1.5.2.2 Aging Management Programs

In Table 3.1-1 of the LRA, the applicant specified the following AMPs as being applicable to the steam generators:

- Chemistry Control Program
- Fluid Leak Management Program
- ISI Plan
- Alloy 600 Aging Management Review
- Flow-Accelerated Corrosion Program
- Steam Generator Surveillance Program

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 SG 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.

The staff notes that, in Table 3.1-1, the Chemistry Control Program is used in conjunction with the ISI Plan to mitigate cracking and loss of material in some SG components. For other SG components, the Chemistry Control Program is complemented by the Alloy 600 Aging Management Review, the Steam Generator Surveillance Program, and the Flow-Accelerated Corrosion Program. The staff finds this general approach to the management of cracking and loss of material to be acceptable, since these additional programs are able to provide feedback on the effectiveness of the Chemistry Control Program during the period of extended operation.

For some SG components requiring AMRs, the applicant proposed that the Chemistry Control Program by itself would be capable of managing the effects of aging attributed to the components. In accordance with Table 3.1-1, the applicant stated that loss of material and cracking in the steam flow limiter, the feedwater thermal sleeves, the handhole diaphragm, and the auxiliary feedwater distribution system are managed by the Chemistry Control Program alone. By letter dated January 28, 2002, the staff requested, in RAI 3.1.5-1, additional clarification of how this AMP will be used to manage loss of material and cracking in these SG components. In its response dated April 15, 2002, the applicant stated that the Chemistry Control Program maintains the environment in the steam generators by controlling contaminants that could lead to loss of material and cracking. A review of the operating experience has not identified any failures due to inadequate chemistry control. This operating experience shows that the Chemistry Control Program is effective in managing loss of material and cracking. Therefore, supplemental activities are not necessary.

Flow restrictors and steam flow limiters are located interior to feedwater/steam flow pipes and, as such, may not be readily accessible for the performance of ISIs. By letter dated January 28, 2002, the staff requested, in RAI 3.1.5-2, the applicant to clarify whether the feedwater flow restrictors were included in all of the SG designs for the McGuire and Catawba units, and to describe the types of ISIs performed on these components. In its response to RAI 3.1.5-2, dated April 15, 2002, the applicant clarified that the feedwater limiters (or flow restrictors) are only present in the Catawba 2 steam generators, and stated that the Chemistry Control Program provides aging management for the feedwater limiter. The applicant also stated that, for the steam flow restrictors identified in Table 3.1-1 (page 3.1-25, row 1) of the LRA, it had incorrectly credited the ISI plan as an aging management program, and that the Chemistry Control Program provides aging management for the steam flow restrictors. Based on the applicant's operating experience, as described in its responses to RAIs 3.1.5-1 and 3.1.5-2, the staff concludes that the Chemistry Control Program is effective in managing loss of material and cracking of the steam flow limiter, the feedwater thermal sleeves, the handhole diaphragm, and the auxiliary feedwater distribution system.

In a letter dated November 21, 2002, the applicant stated that it identified an error of omission in the Catawba/McGuire license renewal application that resulted in an incorrect statement in the NRC's safety evaluation report. In Table 3.1-1 of the original LRA submittal, the applicant identified stainless steel as the material of construction for the steam flow restrictors in all of the McGuire and Catawba steam generators. On the basis of the original submittal, the staff evaluated the aging effects and associated aging management program for the stainless steel steam flow restrictor. However, in the November 21, 2002, letter, the applicant revised Table 3.1-1 to state that the flow restrictors in the McGuire 1 and 2 and Catawba 1 replacement steam generators are made of stainless steel. The flow restrictors in the Catawba 2 original steam generators are made of nickel-based alloy.

The applicant stated that the flow restrictor does not have a pressure boundary function because it is installed completely within the steam generator and is not attached to the secondary side pressure boundary. For the nickel-based alloy flow restrictor, the applicant identified loss of material and cracking as the aging effects, and credits the Chemistry Control Program to manage the aging effects. The staff finds that loss of material and cracking are correctly identified as the aging effects for nickel-based alloy material. The Chemistry Control Program maintains the environment in the steam generators by controlling contaminants that could lead to loss of material and cracking. The applicant stated that, based on the operating experience, there have been no failures caused by inadequate chemistry control. The staff concludes that the Chemistry Control Program is adequate to manage the aging effects on the nickel alloy flow restrictors in Catawba 2 steam generators.

The staff evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of the Chemistry Control Program 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 has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The ISI Plan (Section B.3.20 of LRA Appendix B) manages 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 and Class 2 components complies with the requirements of ASME Section XI, Subsections IWB and IWC. The scope of these Section XI categories covers Class 1 and Class 2 SG components. Depending on the examination category, the methods of inspection may include visual, surface, and/or volumetric examination of weld locations susceptible to aging degradation. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for the steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

By letter dated November 14, 2002, the applicant submitted changes to the license renewal applications for McGuire 1 and 2 and Catawba 1 and 2 for staff review. One of the applicant's proposed changes was related to the steam generator divider plates. In Table 3.1-1 of the LRA, the applicant credited the inservice inspection plan for the aging management of the steam generator divider plates; however, during an inspection of the applicant's inservice inspection plan document (documented in NRC Inspection Report 50-369/02-06, 50-370/02-06, 50-413/02-06, 50-414/02-02, dated September 9, 2002), the NRC staff found that the inservice inspection plan does not include the steam generator divider plates. The applicant determined that the inservice inspection plan was incorrectly credited as an aging management program for the steam generator divider plates. The applicant stated that, because the actual aging management reviews did not take credit for the inservice inspection plan for the divider plates, this was an editorial error in Table 3.1-1 of the LRA.

The divider plate is located in the lower head of the steam generator and separates the hot leg primary coolant from the cold leg primary coolant. The applicant stated that the divider plate is the pressure boundary of the steam generator shell itself. The divider plate is welded to the steam generator shell using nickel-based alloy welds. The pressure boundary of the steam generator could be affected by cracking of the nickel-based alloy divider plate itself, or cracking of the nickel-based alloy weld joining the plate to the shell. The applicant identified cracking and loss of material as the aging effects for the divider plate. The applicant identified the Chemistry Control Program and the Alloy 600 aging management review to manage the aging effects on the divider plate. The Alloy 600 aging management review ensures that cracking for the nickel-based alloy components is adequately managed. The Chemistry Control Program ensures that loss of material of the nickel-based alloy components is adequately managed. The staff has found the applicant's Alloy 600 aging management review to be acceptable for managing the aging effects identified for the divider plate, as shown in Section 3.1.2.2.2 of this SER. The staff has found the Chemistry Control Program to be acceptable for managing the aging effects of loss of material in the divider plate, as shown in section 3.0.3.2 of this SER. On the basis of the information submitted, the staff concludes that, without considering the inservice inspection plan, the aging effects of the steam generator divider plate will be adequately managed by the appropriate aging management programs.

The Alloy 600 Aging Management Review, as described in Appendix B, Section B.3.1 of the LRA, ensures that cracking due to PWSCC for nickel-based alloy components is adequately managed and inspected by the ISI Plan and the Steam Generator Integrity Program. This program utilizes industry and Duke operating experience to define the additional inspection work that needs to be carried out in support of the AMPs identified above. 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 the steam generators. The staff's evaluation of this AMP is documented in Section 3.1.2.2.2 of this SER.

In LRA Table 3.1-1, the applicant has included the SG bolting as one of the SG components requiring aging management. Loss of preload for the manway and handhole cover bolts/studs is covered by the SG bolting group. Table 3.1-1 of the LRA identified that three aging effects, including cracking, loss of material, and loss of preload, will be managed using the ISI plan and the fluid leak management program. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for steam generators. The staff's evaluation of these programs is documented in Sections 3.0.3.9.1 and 3.0.3.6 of this SER, respectively.

The Flow-Accelerated Corrosion Program, as described in Appendix B, Section B.3.14 of the LRA, is designed to manage loss of material from the carbon steel components due to FAC. The applicant states that inspection methods include volumetric examinations using ultrasonic testing and radiography to measure component wall thickness, and visual inspections when access to interior surfaces is possible. The applicant states that this AMP is consistent with the basic guidelines of EPRI Report NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program." The feedwater, auxiliary feedwater, and steam outlet nozzles are susceptible to FAC. The staff has evaluated this common AMP and found it to be acceptable for managing the aging effects identified for steam generators. The staff's evaluation of this AMP is documented in Section 3.0 of this SER.

The Steam Generator Surveillance Program, as described in Section B.3.31 of LRA Appendix B, is designed to manage the loss of material and cracking of Alloy 600 and 690 steam generator tubes, including plugs and sleeves and internal support structures. The applicant stated that this program is based upon Technical Specification requirements, NEI 97-06, and the EPRI PWR Steam Generator Examination Guidelines. The inspections of the tubes and rolled plugs is by eddy current, and those plugs not accessible for eddy current examinations are visually inspected. Table 3.1-1 indicated that only the tubes and tube plugs are identified as applicable to this AMP.

In RAI 2.3.1-4, which pertained to the staff's scoping and screening evaluation that is documented in Section 2.3.1.6.2 of this SER, the staff asked whether it was appropriate to exclude the SG tube support components for McGuire and Catawba from the scope of license renewal. In its April 15, 2002, response to RAI 2.3.1-4, the applicant stated that the SG tube supports are within the scope of license renewal and were subject to AMRs. In its response, the applicant identified that the tube support structures include items such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring and U-bend arch bars for the replacement steam generators used in the McGuire 1 and 2 and Catawba 1 SG designs, and anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates for the Catawba 2 SG designs. The AMR results table for these components, which was provided in the applicant's response to RAI 2.3.1-4, identifies these components as "Tube Supports" and listed cracking and loss of material as applicable effects for these components. The applicant has credited the Chemistry Control Program (specifically for treated water) and the Steam

Generator Surveillance Program to manage loss of material and cracking in the SG tube support components. 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 this system. The staff's evaluation of the Chemistry Control Program is documented in Section 3.0 of this SER. The staff's evaluation of the Steam Generator Surveillance Program follows.

Steam Generator Surveillance Program

The applicant describes its Steam Generator Surveillance Program in Appendix B, Section B.3.31 of the LRA. This section of the LRA describes the applicant's 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 steam generators at all four 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 steam generator components during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The Steam Generator Surveillance Program provides a comprehensive examination of the steam generator tubes and tube supports to ensure that degradation is identified, and corrective actions are taken prior to exceeding allowable limits. This program is a condition monitoring program that is credited for managing loss of material and cracking of Alloy 600 and 690 steam generator tubes and carbon steel and/or stainless steel tube supports.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Appendix B, Section B.3.31, regarding the applicant's demonstration of the Steam Generator Surveillance Program to ensure that the aging effects of loss of material and cracking will be adequately managed, so that intended functions will be maintained consistent with the CLB for the period of extended operation.

The applicant credited the McGuire/Catawba Steam Generator Surveillance Program for managing aging effects in the McGuire/Catawba SG components. The staff evaluated the Steam Generator Surveillance Program on the following seven program 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 documented in the paragraphs that follow. The staff's evaluation of the other three program attributes (confirmatory actions, corrective actions, and administrative controls) for the Steam Generator Surveillance Program is documented in Section 3.0.4 of this SER.

[Program Scope] The scope of the Steam Generator Surveillance Program includes all steam generator tubes (including plugs and sleeves) in each steam generator and internal support structures. The staff issued an RAI to clarify whether the applicant is referring to internal support structures that are directly associated with the tubes themselves, or whether the program is designed to monitor the supports for other steam generator internal components. In its response to RAI 2.3.1-4, the applicant stated that tube support structures on the secondary side of the steam generators are subject to aging management review. The tube support structures include items such as lattice grid support plates, U-bend anti-vibration bars, the shroud, lattice ring, and U-bend arch bars for the replacement steam generators (McGuire 1 and 2 and Catawba 1). For Catawba 2, items such as anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates are included. These items are included as “tube supports,” and the aging management review results are presented in the applicant’s response to this concern. On the basis of this evaluation, the applicant, in its response, stated that Table 3.1.1 of the LRA is supplemented with additional information. The SG tube support components are made out of carbon steel, low-alloy steel, and stainless steel. They are susceptible to cracking and loss of material aging effects. In order to maintain the support function of these SG components, the applicant has credited this program. The staff considers the scope of Duke’s inspection program acceptable because, as discussed below, it meets both Duke’s TS and current industry guidelines, and is adequate to detect degradation of steam generator tubes and internal structures that can affect tube integrity.

[Preventive Actions] The applicant stated that no preventive actions are taken as part of this inspection 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 application stated that the AMP monitors steam generator tube wall degradation and support plate locations. The applicant also stated that the recommendations for steam generator inspections given in NEI 97-06, “Steam Generator Program Guidelines,” and the EPRI PWR Steam Generator Examination Guidelines will be followed as part of this AMP. These guidelines provide, among other things, criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data (including the procedure, probe selection, analysis protocol, and reporting criteria). Following the EPRI guidelines, Duke performs the appropriate type of eddy current test techniques depending on the region of the steam generator (e.g., top of the tubesheet, freespan). Inspection of tubes and plugs is carried out using eddy current examination. Tube plugs that cannot be examined in this way are examined visually. In addition to eddy current testing of SG tubes for tube wall degradation and support plate locations, visual inspections of SG internal components, loose parts monitoring, sludge pile location monitoring, and inspection of welds are performed to monitor the overall condition of the steam generator. The staff considers the parameters monitored (e.g., eddy current test and visual inspection results) acceptable because industry operating experience has demonstrated that the data obtained from these non-destructive examinations provide reasonable assurance that the effects of aging on steam generator tubes and plugs will be detected.

[Detection of Aging Effects] The applicant referred to information in the “Monitoring and Trending” section of the AMP for a description of the procedures for detecting aging effects. Aging effects are detected through inspection of the steam generators following the Improved Technical Specification (ITS) requirements and recommendations of the NEI 97-06, “Steam Generator Program Guidelines,” and EPRI PWR Steam Generator Examination Guidelines.

The staff finds this overall approach for the detection of aging effects to be acceptable because the steam generator tube inspection is based on inspection methods, as specified in the ITS, NEI 97-06, and the EPRI PWR Steam Generator Examination Guidelines, that will be capable of detecting the aging effects identified by the applicant as being applicable to the SG components within the scope of the Steam Generator Surveillance Program.

[Monitoring and Trending]  The applicant monitors degradation from cycle to cycle as part of its commitment to NEI 97-06.  The condition monitoring program applied at these units uses inspection results to ensure that steam generator tube integrity has been maintained over the past operating cycle.  The applicant also considers the inspection results in its operational assessment for the upcoming cycle to ensure that the tubes will perform their intended function and remain within the licensing basis requirements.  The staff considers this acceptable since the program ensures that licensing basis requirements are maintained.

[Acceptance Criteria]  Acceptance criteria for the Steam Generator Surveillance Program are included in Technical Specification 5.5.9.4.  In addition, data are evaluated to determine that all structural and leakage criteria were met during the past operating cycle.  A projection is made by an operational assessment to determine that all tubes left in service will continue to meet licensing basis requirements until the next examination.  The staff finds these acceptance criteria to be acceptable because they are based on licensing basis requirements and technical specification requirements.

[Operating Experience]  The applicant stated that the McGuire 1 and 2 steam generators were replaced in 1997 and 1998, respectively.  The applicant stated that the only degradation that has been identified in the replacement steam generators for these two units is caused by wear at the secondary side U-bend fan bar and lattice grid supports.

After the Catawba 1 SG replacement in 1996, wear at the secondary side U-bend fan bar supports was also detected.  The Catawba 2 steam generators have not been replaced.  Wear was detected in the Catawba 2 steam generators at the edge of anti-vibration bars and in the preheater section.  Tube wear occurs because of interaction between the secondary side of the tubes with steam generator tube support structures.  The applicant stated that the operating experience at Catawba has revealed that wear on the secondary side is very slow and readily detectable by eddy current before it is severe enough to affect tube structural integrity.  The staff finds that Duke’s operating experience to date and the inspection program (which is based on standards, recommendations, and requirements used throughout the industry) supports the applicant’s conclusion that the Steam Generator Surveillance Program is effective.

FSAR Supplement: Subsection (d) of 10 CFR 54.21 requires that the FSAR supplement for the facility must contain 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.  For a description of the applicant’s Steam Generator Surveillance Program, the applicant provided a reference to ITS 5.5.9 in Table 18-1 of LRA Appendices A.1 and A.2 for McGuire and Catawba, respectively.  The staff found that the ITS provides a description of some of the Steam Generator Surveillance Program elements; however, it does not mention the inspection recommendations provided in NEI 97-06.  LRA Section B.3.31 states that, in addition to the technical specification requirements, steam generator tube inspection follows the recommendations of the NEI 97-06 and EPRI PWR Steam Generator Examination Guidelines.  ITS 5.5.9 does not reference NEI 97-06 or the EPRI guidelines.  The staff has not approved

NEI 97-06 or the EPRI guidelines; however, the staff recognizes that these two industry documents provide guidance in the development of a steam generator management program, including steam generator inspection program specifications. The steam generator management program augments the requirements of ITS 5.5.9. Therefore, the staff requested the applicant to include a reference to NEI 97-06 in a summary description of the AMP, or in Table 18-1 of the McGuire and Catawba FSAR supplements. This issue was characterized as SER open item 3.1.5-1.

In its response dated October 28, 2002, the applicant proposed to modify the FSAR supplement summary description of this program. The proposed modifications follow:

1. In Table 18-1, for the Steam Generator Surveillance Program, the applicant proposed to add "18.3 " under the "UFSAR/ITS Location" column to reference the location of the Steam Generator Surveillance Program in the FSAR supplement.
2. The applicant proposed to create a new section, Section 18.3, in the FSAR supplement and include the following statement in Section 18.3, "The inspections of the Steam Generator Surveillance Program follow the recommendations of NEI 97-06, 'Steam Generator Program Guidelines.'"

The staff finds the proposed changes acceptable because the modified FSAR supplement summary description will be consistent with the Steam Generator Surveillance Program described in Appendix B, Section B.3.31, of the Catawba and McGuire LRA. The staff concludes that open item 3.1.5-1 is closed.

On the basis of the review of the Steam Generator Surveillance Program, the staff finds that the implementation of this program will provide reasonable assurance that cracking and loss of material of steam generator tubes and tube supports will be adequately managed, such that the intended function(s) of the steam generators will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.1.5.3 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, the staff concludes that the applicant has demonstrated that the aging effects associated with the SG 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).

### 3.1.6 Aging Management Review for Class 1 Closure Bolting

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to an AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3, and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

*3.1.6.1 Aging Effects*

In its response dated April 15, 2002, the applicant stated that closure bolting used in mechanical system applications would be addressed. Closure bolting in mechanical system applications can be divided between Class 1 and non-Class 1 applications. Although the LRA addressed Class 1 bolting, the applicant described its treatment of this bolting in its response. The applicant stated that Class 1 bolting associated with the RCS is covered by specific ASME Section XI activities and is addressed in Section 3.1 of the LRA. Non-Class 1 bolted closures are considered a subcomponent of the components listed in the tables in LRA Sections 3.2, 3.3, and 3.4 of the LRA. Closure bolting exposed to air, moisture, and leaking fluid (boric acid) environments is subject to aging as a part of the bolted closure to which it belongs. Loss of material is the aging effect requiring management during the period of extended operation for carbon and low-alloy steel fastener sets of bolted closures.

*3.1.6.2 Aging Management Programs*

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components are credited with managing this aging effect during the period of extended operation. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects of Class 1 bolting. The staff's evaluation of these common AMPs is documented in Section 3.0 of this SER.

*3.1.6.3 Conclusions*

On the basis of its review of the RAI response pertaining to Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments identified. The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for Class 1 closure bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff concludes that the applicant has demonstrated that the aging effects associated with Class 1 bolting will be adequately managed, so that there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.2 Aging Management of Engineered Safety Features

The applicant described its AMR of the engineered safety features (ESFs) for license renewal in Sections 2.3.2, “Engineered Safety Features,” and 3.2, “Aging Management of Engineered Safety Features,” of its LRA. The staff has reviewed these sections of the application to determine whether the applicant has provided adequate information to demonstrate that the effects of aging on ESF systems and components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The LRA identified eight systems that will require aging management to meet the requirements of 10 CFR 54.21(a)(3) for management of aging effects. The eight systems are annulus ventilation, containment isolation, containment air return exchange and hydrogen skimmer, containment spray, containment valve injection water, refueling water, residual heat removal, and safety injection. The LRA included a summary of the results of the aging management review for the above listed eight systems. The results are presented in Tables 3.2-1 through 3.2-8 of the LRA. The tables provide the following information: (1) component type, (2) component function, (3) material, (4) environment, (5) aging effects requiring management, and (6) the aging management programs that manage the identified aging effects.

Section 3.2 of the LRA defined the external and internal environments applicable to the ESF systems as follows—

- Air-Gas — Compressed air is ambient air that has been filtered and compressed for use in plant equipment. Compressed air may be either dry or oiled. Compressed gasses include carbon dioxide, hydrogen, nitrogen, freon, or refrigeration gasses used to replace freon due to environmental concerns.
- Borated Water — Borated water is demineralized water treated with boric acid.
- Raw Water — Raw water is water from a lake, pond, or river that has been rough-filtered and possibly treated with a biocide.
- 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.
- Sheltered environment — The ambient conditions within the sheltered environment may or may not be controlled. The sheltered environment atmosphere is a moist air environment. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.
- 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.
- Ventilation — Ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy.
- Yard — Yard environment is a moist air environment in which equipment is exposed to heat, cold, and precipitation.

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 McGuire and Catawba, Duke also performed a review of industry experience and NRC generic communications relative to the ESF SSCs. In addition, relevant McGuire and Catawba operating experience has been reviewed to provide additional confidence that the set of aging effects for the specific material-environment combinations have been identified.

### 3.2.1 Annulus Ventilation System

#### *3.2.1.1 Technical Information in the Application*

The McGuire annulus ventilation system is an ESF that creates and maintains a negative pressure zone in the annular space between the steel primary containment and reactor building (secondary containment) to prevent the leakage of radioisotopes through the reactor building and into the environment following a loss-of-coolant accident (LOCA). The annulus ventilation system is also designed to maintain containment isolation integrity. The Catawba annulus ventilation system is an ESF, used in conjunction with the secondary containment to limit operator and site boundary doses following a design basis accident, and to provide long-term fission product removal capability within the annulus through holdup and filtration.

##### 3.2.1.1.1 Aging Effects

Table 3.2-1 of the LRA identified the following components that will require aging management during the period of extended operation: air flow monitors, ductwork, filters, pipe, tubing, and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the annulus ventilation components. The applicant also indicated that the environments to which these components are exposed include an internal environment of ventilation and external environments of sheltered or reactor building. The applicant identifies only loss of material as an applicable aging effect for carbon steel, copper, and brass that are exposed to an external environment.

##### 3.2.1.1.2 Aging Management Programs

The LRA identified the following two aging management programs to manage the aging effects on the annulus ventilation system during the period of extended operation:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The applicant stated that the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components will be used to manage the loss of material associated with carbon steel materials. The Fluid Leak Management Program will also be used to manage the loss of material associated with brass and copper materials. A detailed description concerning each of the programs identified above is included in Appendix B of the LRA, along with the applicant’s discussion of how identified aging effects will be effectively managed for the period of extended operation.

#### *3.2.1.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the annulus ventilation system will be adequately managed, so that the intended function of the systems will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.1.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the annulus ventilation system. The results are presented in Table 3.2-1 of the LRA. The materials of construction, internal/external environment, and aging effects for the annulus ventilation system are—

- stainless steel in ventilation/sheltered/reactor building environments — no aging effects
- carbon steel, brass, copper in ventilation environments — no aging effects
- carbon steel in sheltered/reactor building environments — loss of material
- brass, copper in sheltered/reactor building environments — loss of material

No aging effects were identified for air flow monitors, ductwork, filters, tubing, and valve bodies made of stainless steel in ventilation or sheltered environments. Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building air environments. Therefore, the applicant has not identified any applicable aging effects for the surfaces of stainless steel annulus ventilation system components exposed to these types of air environments.

No aging effects were identified for carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

Loss of material was identified for carbon steel pipe and valve bodies in sheltered air or reactor building air environments. Loss of material of carbon steel materials by corrosion may result in moist air environments and, therefore, may be an applicable aging effect for the surfaces of carbon steel that are exposed to sheltered air. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components to manage the loss of material associated with carbon steel pipe and valve bodies.

Loss of material was identified for brass tubing, brass valve bodies, and copper tubing in the sheltered environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the Fluid Leak Management Program to manage the loss of material associated with brass and copper materials.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function. The applicant identified cracking and shrinkage of structural sealants in the interface between a structural wall, floor, or ceiling, and a nonstructural component (such as a duct, piping, electrical cables, doors, and nonstructural walls) resulting from exposure to ambient conditions as potential aging effects.

The aging effects identified in LRA Table 3.2-1 and in correspondence from the applicant are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.1.2.2 Aging Management Programs

Table 3.2-1 of the LRA identified the following two aging management programs that will manage the aging effects on the annulus ventilation system during the period of extended operation:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The Fluid Leak Management Program, the Inspection Program for Civil Engineering Structures and Components, and the Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-1 and correspondence from the applicant, the staff concludes that the above identified AMPs will effectively manage the aging effects of the annulus ventilation system, and that there is reasonable assurance that the intended functions of the annulus ventilation system will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.2.1.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA and in correspondence from the applicant . The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the annulus ventilation system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the annulus ventilation system, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.2 Containment Isolation System

*3.2.2.1 Technical Information in the Application*

The containment isolation system is an ESF that prevents the leakage of uncontrolled or unmonitored radioactive materials to the environment by closing all fluid penetrations not required for operation of the Engineered Safeguards System. The LRA identifies the following 12 subsystems of the containment isolation system:

Breathing air system: The McGuire breathing air system provides an adequate capacity of air to meet appropriate American National Standards Institute (ANSI) specifications. The breathing air system is also relied upon to provide and maintain containment isolation and closure. The Catawba breathing air system supplies clean, oil free, compressed air to various locations in the auxiliary building, monitor tank building, and containment for breathing protection against airborne contamination during the performance of certain maintenance and cleaning operations.

Containment air release and addition system: The McGuire containment air release and addition system maintains containment pressure between the McGuire Technical Specification limits of -0.3 to +0.3 psig. Increases in pressure during normal operation are controlled by venting the containment through the containment air release and addition filters. The Catawba containment air release and addition system maintains containment pressure between the Catawba Technical Specification limits of -0.1 to +0.3 psig during normal plant operation. An increase in pressure during normal operation is controlled by the containment air release fans taking suction from the containment and passing through the containment air release filters.

Containment hydrogen sample and purge system: The McGuire Nuclear Station has no system corresponding to the Catawba containment hydrogen sample and purge system. The Catawba containment hydrogen sample and purge system is used after a loss-of-coolant accident (LOCA) to monitor the hydrogen concentration inside containment, and if necessary, reduce the levels of hydrogen by manually purging the hydrogen from containment into the annulus.

Containment purge ventilation system: During periods of sustained personnel access (including refueling), the McGuire containment purge ventilation system reduces the airborne radioactivity levels in containment by purging the upper containment atmosphere to the environment via the unit vent stack. The Catawba containment purge system reduces the airborne radioactivity levels in containment by purging the upper containment, lower containment, and the in-core instrumentation room atmosphere to the unit vent stack when periods of personnel access are required.

Containment ventilation cooling water system: The McGuire containment ventilation cooling water system operates in conjunction with the nuclear service water system to supply cooling water to ventilation units located in the reactor and auxiliary buildings. Catawba does not have a containment ventilation cooling water system. The comparable components cooled by the McGuire containment ventilation cooling water system are cooled by the Catawba nuclear service water system.

Conventional chemical addition system:  The McGuire conventional chemical addition system uses the auxiliary feedwater supply headers to provide chemical addition to the steam generators.  Catawba does not have a conventional chemical addition system.  The comparable components to the McGuire conventional chemical addition system are contained in the Catawba auxiliary feedwater system.

Equipment decontamination system:  The McGuire equipment decontamination system provides decontamination of station equipment before personnel use.  The original design of McGuire included containment isolation capability; however, the design was modified by the installation of a sleeve cap on the annulus side of the penetration, thereby removing the containment isolation function.  Associated with the capped penetration are remaining components, including piping.  The applicant determined that these components have no component intended function.  Therefore, no mechanical components in the equipment decontamination system are subject to aging management review.  The Catawba equipment decontamination system provides cleaning and decontamination of radioactive equipment prior to handling, maintenance, or shipping.  The equipment decontamination system and its components are not safety-related, with the exception of the portions associated with containment isolation.  The equipment decontamination system is relied upon to maintain two trains of containment isolation and maintain containment closure for shutdown.

Ice condenser refrigeration system:  The primary safety function of the McGuire and Catawba ice condenser refrigeration systems is to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptable levels, consistent with the operation of other associated systems.  The safety-related function of the mechanical systems portion of the ice condenser refrigeration system is containment isolation.

Makeup demineralized water system:  The McGuire and Catawba makeup demineralized water systems provide treated and demineralized water to various plant systems and components.

Station air system:  The McGuire station air system provides an adequate capacity for general station service air requirements.  Normally, the instrument air system provides the station air requirements through system cross-connect valves.  However, if needed, one station air system compressor is provided to furnish the station air requirements if the instrument air system is not available or desired.  The station air system is also relied upon to provide and maintain containment isolation and closure.  The Catawba station air system supplies low pressure compressed air for air operated tools, miscellaneous equipment, and various maintenance purposes.  The station air system, if required, is available to act as a backup supply of compressed air for the instrument air system.  The station air system is relied upon to provide and maintain containment isolation and closure.

Steam generator blowdown recycle system:  The McGuire and Catawba steam generator blowdown recycle systems are used in conjunction with the condensate system to maintain acceptable secondary side water chemistry and control corrosion product buildup.  The steam generator blowdown recycle system is designed to maintain containment isolation integrity.  The system automatically isolates the blowdown lines penetrating the containment following receipt of a containment isolation signal, and also following a start signal of the auxiliary feedwater system.

Steam generator wet lay-up recirculation system: The McGuire and Catawba steam generator wet lay-up recirculation systems maintain containment isolation integrity. The system contains piping and components that are used during containment isolation.

3.2.2.1.1 Aging Effects

Table 3.2-2 of the LRA identifies the following components of the containment isolation system that will require aging management: piping, tubing, orifices, annubars, and valve bodies. The applicant identified stainless steel, carbon steel, copper, brass, and transite, a non-metallic cement-asbestos material, as the materials of construction for the containment isolation components. The applicant identified the reactor building, sheltered, and embedded environments as the external environments, and raw water, treated water, borated water, air-gas, and ventilation environments as the internal environments. Loss of material was identified as an applicable aging effect for carbon steel, copper, and brass materials. Loss of material and cracking were identified as applicable aging effects for stainless steel materials.

3.2.2.1.2 Aging Management Programs

The LRA identified the following six aging management programs that will manage the aging effects on the containment isolation system during the period of extended operation:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program
- Galvanic Susceptibility Inspection
- Chemistry Control Program
- Flow-Accelerated Corrosion Program

Appendix B to the LRA contains a detailed description of the six previously discussed aging management programs. The LRA cites these programs as methods to manage aging effects of the containment isolation system components in the applicable environments.

*3.2.2.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the containment isolation system while maintaining the current licensing basis of the system’s intended function.

3.2.2.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the containment isolation system. The results are presented in Table 3.2-2 of the LRA. The materials of construction, internal/external environments, and aging effects for the containment isolation system are—

- stainless steel in air-gas/sheltered/reactor building/ventilation environment — no aging effects
- embedded transite, carbon and stainless steel — no aging effects

- carbon steel, brass, copper, and transite in ventilation environment — no aging effects
- carbon steel in sheltered/reactor building environment — loss of material
- brass and copper materials in reactor building environment — loss of material
- carbon steel in raw water environment — loss of material
- stainless steel in raw water environment — loss of material
- stainless steel in treated water environment — loss of material and cracking
- carbon steel in treated water environment — loss of material
- stainless steel in borated water environment — loss of material and cracking

No aging effects were identified for piping, tubing, orifices, annubars, and valve bodies made of stainless steel in air-gas, sheltered, reactor building, or ventilation environments. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

No aging effects were identified for pipe made of transite, carbon, or stainless steel in an embedded environment.

No aging effects were identified for carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in sheltered and reactor building environments. Loss of material of carbon steel materials by corrosion may occur in moist air environments and, therefore, may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components to manage the loss of material associated with carbon steel pipe and valve bodies.

The applicant identified loss of material as an aging effect on brass valve bodies, brass tubing, and copper tubing in the reactor building environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the Fluid Leak Management Program to manage the loss of material associated with brass and copper materials.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in the raw water environment. Loss of material from general corrosion, microbiologically induced corrosion (MIC), galvanic corrosion, and pitting corrosion can occur when carbon steel materials are in contact with raw water. The applicant will use the Galvanic Susceptibility Inspection and Service Water Piping Corrosion Program to manage the loss of material associated with carbon steel pipe and valve bodies.

The applicant identified loss of material as an aging effect on stainless steel orifices, annubars, tubing, and valve bodies in the raw water environment. Loss of material from galvanic, MIC, and pitting corrosion can occur when stainless steel materials are in contact with raw water. The applicant will use the Service Water Piping Corrosion Program to manage the loss of material associated with stainless steel orifices, annubars, tubing, and valve bodies.

The applicant identified loss of material and cracking as aging effects on stainless steel tubing, pipe, and valve bodies in the treated water environment. Loss of material and cracking of stainless steel in a treated water environment is a possible aging effect under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low flow conditions could lead to loss of material from and cracking of stainless steel in treated water. Therefore, the applicant will use the Chemistry Control Program to manage the loss of material and cracking in the treated water environment.

The applicant identified loss of material and cracking as aging effects on stainless steel in the borated water environment. Loss of material and cracking of stainless steel in this environment is a possible aging effect under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb, oxygen in excess of 100 pbb, and temperature in excess of 200 °F in stagnant or low flow conditions can lead to loss of material and cracking. Therefore, the applicant will use the Chemistry Control Program to manage the loss of material and cracking in the borated water environment.

The aging effects identified in LRA Table 3.2-2 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.2.2.2 Aging Management Programs

In Table 3.2-2 of the LRA, the applicant identified the following programs that will manage the aging effects associated with the containment isolation system:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program
- Galvanic Susceptibility Inspection
- Chemistry Control Program
- Flow-Accelerated Corrosion Program

The Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, Service Water Piping Corrosion Program, Galvanic Susceptibility Inspection, Chemistry Control Program, and Flow-Accelerated Corrosion Program are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the containment isolation system, and that there is reasonable assurance that the intended functions of the containment isolation system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.2.2.3 Conclusions*

The staff reviewed the information in Section 3.2, “Aging Management of Engineered Safety Features,” of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant’s characterization of the aging effects associated with the containment isolation system is consistent with published literature and industry experience. The staff further concludes the applicant has appropriate aging management programs to effectively manage the aging effects of the containment isolation system, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.3 Containment Air Return Exchange and Hydrogen Skimmer System

*3.2.3.1 Technical Information in the Application*

The McGuire and Catawba containment air return exchange and hydrogen skimmer system (1) maintains containment pressure less than the design pressure during any high energy line break (HELB), (2) ensures hydrogen concentration remains less than the flammability limit during a LOCA, and (3) maintains containment isolation integrity for the system piping penetrating the containment.

3.2.3.1.1 Aging Effects

Table 3.2-3 of the LRA identifies the following components that will require aging management: ductwork, expansion joints, pipe, tubing and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the containment air return exchange and hydrogen skimmer components. Loss of material was identified as an applicable aging effect for carbon steel, copper, and brass exposed to the reactor building or a sheltered external environment.

3.2.3.1.2 Aging Management Programs

The LRA identifies the following two aging management programs that will manage the aging effects on the containment air return exchange and hydrogen skimmer systems during the period of extended operation:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The applicant indicated that the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components will be used to manage the loss of material associated with carbon steel materials. The applicant stated that the Fluid Leak Management Program will be used to manage the loss of material associated with copper and brass materials. Appendix B to the LRA contains a detailed description of those two aging management programs.

*3.2.3.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the containment air return exchange and hydrogen skimmer system while maintaining the current licensing basis of the system's intended function.

3.2.3.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the containment air return and hydrogen skimmer system. The results are presented in Table 3.2-3 of the LRA. The materials of construction, internal/external environments, and aging effects for the containment air return exchange and hydrogen skimmer system are—

- stainless steel in air-gas/ventilation/sheltered/reactor building environment — no aging effects
- brass, copper, and carbon steel in ventilation environment — no aging effects
- brass and copper in reactor building environment — loss of material
- carbon steel in sheltered/reactor building environment — loss of material

No aging effects were identified for ductwork, expansion joints, piping, tubing, and valve bodies made of stainless steel in air-gas, sheltered, reactor building, or ventilation environments. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

The applicant identified loss of material as an aging effect on carbon steel pipe and valve bodies in sheltered or reactor building environments. Loss of material of carbon steel materials by corrosion may occur in moist air environments and, therefore, may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components to manage the loss of material associated with carbon steel pipe and valve bodies.

No aging effects were identified for brass and copper tubing and carbon steel pipe and valve bodies in a ventilated air environment. The air temperature, humidity, and component temperatures do not provide a corrosive environment that would lead to aggressive general corrosion.

The applicant identified loss of material as an aging effect on brass and copper tubing in the reactor building environment. Brass and copper are corrosion resistant in both dry or moist air environments. However, borated water leaks from other plant systems may cause loss of material of brass and copper components. The applicant will use the Fluid Leak Management Program to manage the loss of material associated with these materials.

The aging effects identified in LRA Table 3.2-3 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.3.2.2 Aging Management Programs

Table 3.2-3 of the LRA credits the following two aging management programs for managing the aging effects on the containment air return exchange and hydrogen skimmer systems during the period of extended operation:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the containment air return exchange and hydrogen skimmer system, and that there is reasonable assurance that the intended functions of the containment air return exchange and hydrogen skimmer system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.2.3.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the containment air return exchange and hydrogen skimmer system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the containment air return exchange and hydrogen skimmer system, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.4 Containment Spray System

*3.2.4.1 Technical Information in the Application*

The applicant described its AMR for the containment spray system (CSS) in Section 3.2 of the LRA. The CSS removes thermal energy from the containment atmosphere in the event of a LOCA or main steam line break. The CSS performs this function in conjunction with the emergency core cooling systems, which cool the reactors during injection and recirculation modes of emergency operations. The heat removal capabilities of the CSS maintain the containment pressures to below the design pressure values after the ice in the respective ice condensers has been depleted. The CSS also serves to remove fission product iodine from the post-accident containment atmospheres.

3.2.4.1.1 Aging Effects

Table 3.2-4 of the LRA identified the following components that are subject to AMRs: flow orifices, heat exchangers and their subcomponents, piping, pump casings, spray nozzles, tubing, and valve bodies. In Table 3.2-4 of the LRA, the applicant identifies that the specific CSS components are fabricated from stainless steel materials, with the following exceptions:

- Portions of the CSS heat exchanger channel heads and shells are fabricated from carbon steel.
- Tubing for McGuire CSS heat exchanger 2NSHX0004 is fabricated from titanium instead of stainless steel.
- Portions of the Catawba CSS heat exchanger tubesheets are fabricated from carbon steel.

Loss of material was identified as an applicable aging effect for carbon steel materials. Loss of material and fouling were identified as applicable aging effects for heat exchanger tubes. Loss of material and cracking were identified with stainless steel materials.

3.2.4.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects identified for the CSS components:

- Borated Water Systems Stainless Steel Inspection
- Chemistry Control Program
- Fluid Leak Management Program
- Heat Exchanger Performance Testing Activities — Containment Spray Heat Exchangers
- Heat Exchanger Preventive Maintenance Activities — Containment Spray
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program

*3.2.4.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 (including Table 3.2-4), and pertinent sections of LRA Appendices A and B, to ascertain that the effects of aging associated with CSS will be adequately managed, so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.4.2.1 Aging Effects

Table 3.2-4 of the application identifies which of these aging effects are applicable to the specific CSS components identified in the table as being within the scope of license renewal.

Specifically, Table 3.2-4 identifies the following aging effects for the material-environment combinations for the CSS components:

- stainless steel components in borated water environments — loss of material and cracking
- stainless steel or titanium tubes in raw water environments — loss of material and fouling
- titanium tubes in borated water environments — no aging effects identified
- other stainless steel components in raw water environments- loss of material
- stainless steel components in contact with sheltered air, ventilation air, or reactor building air environments — no aging effects identified
- carbon steel components in external sheltered air environments or internal raw water environments — loss of material

Industry experience and experimental data have demonstrated that austenitic stainless steel materials in borated water solutions may be susceptible to stress corrosion cracking or loss of material as a result of pitting or general corrosion, with elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increasing the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel CSS components in contact with borated water solutions. These aging effects are also applicable to portions of the stainless steel CSS piping (i.e., the CSS piping risers) that are exposed to alternating borated-wet and dry-air environments, as any oxidizing contaminants may concentrate in the piping sections and create an environment conducive to pitting or stress corrosion cracking. For stainless steel (or titanium) heat exchanger tubes exposed to raw water environments, the tubes may be susceptible to biological-induced fouling, which if unattended, has the potential to block the flow of coolant through the tubes and, in some cases, to produce corrosive environments that could lead to a loss of the tube material. The applicant has appropriately identified these aging effects (i.e., cracking, loss of material, fouling) in its analyses for the CSS stainless steel components that are exposed to borated or raw water sources, or to alternating borated-wet and dry-air environments.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, cracking and corrosion generally have not been a problem for austenitic stainless steel components in ventilated air, sheltered air, or reactor building air environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel CSS components exposed to these types of air environments. Based on these considerations, the staff concludes that the applicant's identification of the aging effects for stainless steel CSS components is acceptable.

The carbon steel CSS heat exchanger components are in contact with sheltered air environments on their external surfaces, and the carbon steel and stainless steel heat exchanger components are in contact with raw water on their internal surfaces. Loss of material of carbon steel materials by corrosion may result in moist air environments and, therefore, may be an applicable aging effect for the surfaces of carbon steel CSS heat exchanger components that are exposed to sheltered air. The surfaces of carbon steel CSS heat exchanger components that are exposed to raw water environments may be prone to loss of material as a result of general or localized corrosion, or by erosion from particulate, when the raw water flow velocities are high. The carbon steel CSS heat exchanger components in contact with stainless steel heat exchanger components may be prone to loss of material by corrosion, if the adjacent stainless steel heat exchanger component is subjected to an internal, corrosive borated water or raw water environment, and if the stainless steel component has cracked sufficiently to allow fluid to leak onto the external surfaces of the carbon steel component. The applicant has appropriately identified loss of material as an applicable aging effect for the carbon steel CSS heat exchanger components that are exposed to these environments.

The aging effects identified in LRA Table 3.2-4 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.2.4.2.2 Aging Management Programs

Table 3.2-4 of the LRA states that the following aging managements programs are credited for managing the aging effects attributed to the CSS components:

- Borated Water Systems Stainless Steel Inspection
- Chemistry Control Program
- Fluid Leak Management Program
- Performance Testing Activities — Containment Spray Heat Exchangers
- Heat Exchanger Preventive Maintenance Activities — Containment Spray
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program

The applicant will use the Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) and the Inspection Program for Civil Engineering Structures and Components (Section B.3.21 of LRA Appendix B) to manage loss of material in carbon steel CSS components exposed to sheltered air environments. The applicant will use the Performance Testing Activities — Containment Spray Heat Exchangers (Section B.3.17.2 of LRA Appendix B) and the Heat Exchanger Preventive Maintenance Activities — Containment Spray (Section B.3.17.2 of LRA Appendix B) to manage fouling and loss of material in the heat exchanger tube surfaces (stainless steel or titanium) that are exposed to raw water environments, respectively. The applicant will use the Service Water Piping Corrosion Program (Section B.3.29 of LRA Appendix B) to manage the surfaces of carbon or stainless steel components exposed to raw water environments. The applicant will use the Chemistry Control Program (Section B.3.6 of LRA Appendix B) to manage loss of material and cracking in stainless steel CSS components exposed to borated water environments. As an added precaution, the applicant will use the Borated Water Systems Stainless Steel Inspection (Section B.3.4 of LRA Appendix B) as an added program for managing loss of material and cracking in the stainless steel CSS piping risers, as the risers may be subjected to periods of alternating wet, borated water and dry air environments.

The Borated Water Systems Stainless Steel Inspection program, Chemistry Control Program, Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Service Water Piping Corrosion Program are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Heat Exchanger Performance Testing Activities — Containment Spray Heat

Exchangers Program and the Heat Exchanger Preventive Maintenance Activities — Containment Spray Program follows.

<u>Performance Testing Activities — Containment Spray Heat Exchangers</u>

The applicant described its performance testing activities of the containment spray heat exchangers in Section B.3.17.2.1 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

The applicant stated that the purpose of the Performance Testing Activities — Containment Spray Heat Exchangers is to manage fouling of stainless steel and titanium heat exchanger tubes that are exposed to raw water. The Performance Testing Activities — Containment Spray Heat Exchangers is a performance monitoring program that monitors specific component parameters to detect the presence of fouling, which can affect the heat transfer function of the component.

The staff's evaluation of the Performance Testing Activities — Containment Spray Heat Exchangers 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.

[Program Scope] The scope of the Performance Testing Activities — Containment Spray Heat Exchangers includes the McGuire and Catawba containment spray heat exchanger tubes. The staff finds the scope to be appropriate because it includes the stainless steel and titanium heat exchanger tubes that are exposed to raw water and have the potential for fouling.

[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 finds this acceptable and agrees with the applicant that the purpose of the performance testing activities is to detect, not prevent, tube fouling.

[Parameters Monitored or Inspected] The Performance Testing Activities — Containment Spray Heat Exchangers involve monitoring of heat transfer capability by performance of a heat capacity test. Based on a review of the program purpose and scope, the staff finds the parameters being monitored or inspected to be acceptable because they enable the applicant to identify tube fouling before the loss of component intended function.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under Monitoring and Trending, Performance Testing Activities — Containment Spray Heat Exchangers will detect fouling prior to loss of the component intended function. The staff agrees that the applicant is capable of identifying tube fouling prior to loss of intended function through performance testing.

[Monitoring and Trending] The applicant stated that Performance Testing Activities — Containment Spray Heat Exchangers involve calculation of a raw water fouling factor using tube and shell side inlet and outlet temperatures and flow rates. The applicant then uses the results of the fouling factor calculation to trend against a baseline value for indication of tube (heat transfer surface) cleanliness. The applicant stated that the procedures are performed on each of the containment spray heat exchangers annually at Catawba and every 3 years at McGuire. The applicant refers to information provided under operating experience as justification for the extended frequency at McGuire.

Based on the review of the monitoring and trending information provided in the application, the staff finds the monitoring and trending activities acceptable because they allow the applicant to identify fouling or degradation in a timely manner, given the type of inspections performed and the frequency.

[Acceptance Criteria] The applicant stated that the acceptance criteria of the Performance Testing Activities — Containment Spray Heat Exchangers are established by heat removal capacity calculations. The comparison of the calculated to the measured heat removal capacity must ensure that the heat exchangers are able to perform their design basis function. The staff's review found the acceptance criteria to be acceptable because it allows the applicant to identify tube fouling and take corrective action prior to loss of component function.

[Operating Experience] The applicant stated that operating experience has demonstrated that heat capacity tests provide adequate indication to predict when corrective action is required for heat transfer surface fouling. Corrective action in the form of tube cleaning, for example, is performed before the loss of the component intended function. Because the containment spray heat exchangers are used for emergency functions only, the applicant stated that placing the heat exchangers in wet lay-up several years ago has minimized buildup of fouling materials on the tubes. The applicant stated that the wet lay-up has proven so successful at McGuire that the frequency of heat capacity testing has been extended to a 3-year frequency. Experience has shown that a 3-year frequency allows for timely corrective action. Corrective action in the form of tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity.

Based on the review of the applicant's operating experience with the performance testing activities, the staff finds that a basis exists for the extended interval between activities at McGuire. The staff also found that the operating experience demonstrates the effectiveness of the Performance Testing Activities — Containment Spray Heat Exchangers in identifying tube fouling before it can affect system performance.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.2, for McGuire, and LRA Appendix A-2, Section 18.2.12.2, for Catawba, the applicant has provided proposed FSAR supplements summary descriptions of the program. The staff reviewed this information and found it to be consistent with the information provided in LRA Appendix B, Section B.3.17.2.1, and is therefore acceptable.

The staff reviewed the information in Section B.3.17.2.1 of LRA Appendix B. On the basis of its review and the above evaluation, the staff concludes that the applicant has demonstrated that the effects of aging associated with the Performance Testing Activities — Containment Spray Heat Exchangers program will be adequately managed, so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Heat Exchangers Preventive Maintenance Activities — Containment Spray

The applicant described its Heat Exchangers Preventive Maintenance Activities — Containment Spray in Section B.3.17.2.2 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

The applicant stated that the purpose of the Heat Exchangers Preventive Maintenance Activities — Containment Spray is to manage loss of material for parts of the containment spray heat exchanger exposed to raw water. The Heat Exchangers Preventive Maintenance Activities — Containment Spray is a 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 of the heat exchanger. The applicant credits this program with managing loss of material for stainless steel and titanium materials.

The staff's evaluation of the Heat Exchangers Preventive Maintenance Activities — Containment Spray 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.

[Program Scope] The applicant defined the scope of the Heat Exchangers Preventive Maintenance Activities — Containment Spray to include the McGuire and Catawba containment spray heat exchanger tubes. The applicant relies on other aging management programs, such as the Chemistry Control Program, to manage the aging effects of the heat exchanger shell, channel head, and tubesheets. The staff finds that the scope is appropriate for the described purpose, because it includes those major components in the containment spray system exposed to raw water.

[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, not to prevent such loss.

[Parameters Monitored or Inspected] The applicant stated that the Heat Exchangers Preventive Maintenance Activities — Containment Spray inspects the heat exchanger tubes to provide an indication of loss of material. The staff finds 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 the Heat Exchangers Preventive Maintenance Activities — Containment Spray will be capable of detecting loss of material due to crevice, pitting, and microbiologically influenced corrosion prior to loss of the component intended functions.  The inspections are performed periodically, and the program is capable of detecting and correcting aging degradation before loss of component function.  Therefore, the staff finds this attribute acceptable.

[Monitoring and Trending]  The applicant stated that the Heat Exchangers Preventive Maintenance Activities — Containment Spray performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material.  At Catawba, NDT is performed on the perimeter tubes of each containment spray heat exchanger at least every 5 years.  The applicant's program requires analysis following each NDT to determine the need for further testing, replacement, or repair.  The applicant noted that the perimeter tubes comprise approximately 15 percent of the total tubes.  At McGuire, NDT is performed on each heat exchanger as needed based on operating experience and engineering evaluation of test data.  Based on the information provided in the application, the staff finds that because the monitoring is done at a regular frequency (Catawba) or based on operating experience and engineering judgment (McGuire), the program is capable of detecting and correcting aging degradation before loss of component function.

[Acceptance Criteria]  The applicant stated that the acceptance criterion for the Heat Exchangers Preventive Maintenance Activities — Containment Spray is no loss of material of the tubes that could result in a loss of the component intended function, as determined by engineering judgment.  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 staff 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 was characterized as open item 3.0.3.9.1.2(c).

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.

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 operating experience associated with the Heat Exchangers Preventive Maintenance Activities — Containment Spray has demonstrated that the eddy current testing provides adequate information on the extent of wall loss present in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed by the applicant before the loss of the component intended function.

The applicant noted that some tube plugging has occurred, particularly early in service life. At Catawba, the applicant stated that the tube plugging rate has been essentially flat for the past several years due to operational improvements, including placing the heat exchangers in wet lay-up. The wet lay-up has proven so successful at McGuire that, according to the applicant, most recent test results indicate negligible tube wall degradation over several years. The staff agrees that because the monitoring methods are based on proven NDT techniques, and based on operating experience, the program is reliable to identify loss of material and take corrective action before loss of component function.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.2, and LRA Appendix A-2, Section 18.2.12.2, the applicant has provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17.2.2 of the LRA and is therefore acceptable.

The staff reviewed the information in Section B.3.17.2.2, Appendix B of the LRA. On the basis of its review and the above evaluation, and with the resolution of SER open item 3.0.3.9.1.2(c), the staff concludes that the applicant has demonstrated that the effects of aging associated with the Heat Exchangers Preventive Maintenance Activities — Containment Spray program will be adequately managed, so that there is reasonable assurance that these components will perform their intended function(s) consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of Table 3.2-4 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the CSS, and that there is reasonable assurance that the intended functions of the CSS will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.2.4.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the CSS is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the CSS, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.5 Containment Valve Injection Water System

#### *3.2.5.1 Technical Information in the Application*

The McGuire Nuclear Station does not have containment valve injection water system. The Catawba Nuclear Station containment valve injection water system is designed to inject water between the two seating surfaces of double disc gate valves used for containment isolation. The injection pressure is higher than containment design peak pressure during a LOCA. This will prevent leakage of the containment atmosphere through the gate valves, thereby reducing potential offsite dose below the values specified by Title 10 CFR Part 100 limits following the postulated accident.

##### 3.2.5.1.1 Aging Effects

Table 3.2-5 of the LRA identified the following components that will require aging management during the period of extended operation: pipe, tanks, tubing, and valve bodies. The material of construction for the above listed components is stainless steel. Loss of material and cracking were identified as applicable aging effects for the containment valve injection water system.

3.2.5.1.2 Aging Management Programs

The LRA identified that the Treated Water Systems Stainless Steel Inspection aging management program will manage the aging effects on the containment valve injection water system during the period of extended operation. A detailed description of the program is included in Appendix B of the LRA, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation.

### *3.2.5.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging for the containment valve injection water system will be adequately managed, so that the intended function of the systems will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.5.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the containment valve injection water system. The results are presented in Table 3.2-5 of the LRA. The materials of construction, internal/external environment, and aging effects for the containment valve injection water system are—

- stainless steel in sheltered/reactor building environment — no aging effects
- stainless steel in treated water environment — loss of material and cracking

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, cracking and corrosion generally have not been a problem for austenitic stainless steel components in sheltered air or reactor building air environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel containment valve injection water system components exposed to these types of air environments.

Loss of material and cracking in stainless steel were identified as aging effects in a treated water environment. Loss of material and cracking of stainless steel in a treated water environment is a possible aging effect under certain conditions. Industry experience indicated that the presence of halogens in excess of 150 ppb and oxygen in excess of 100 ppb in stagnant or low flow conditions could lead to loss of material and cracking of stainless steel in a treated water environment. Therefore, the applicant will use the Treated Water Systems Stainless Steel Inspection program to manage the loss of material and cracking in a treated water environment.

The aging effects identified in LRA Table 3.2-5 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.2.5.2.2 Aging Management Programs

The applicant identified that the Treated Water Systems Stainless Steel Inspection aging management program will be used to manage the aging effects associated with the containment valve injection water system. The Treated Water Systems Stainless Steel Inspection aging management program is credited with managing the aging 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-5, the staff concludes that the above identified AMP will effectively manage the aging effects of the containment valve injection water system, and that there is reasonable assurance that the intended functions of the containment valve injection water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### *3.2.5.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the containment valve injection water system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the containment valve injection water system, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.2.6 Refueling Water System

### *3.2.6.1 Technical Information in the Application*

The McGuire refueling water system provides a source of borated water to be used during refueling, and for the emergency core cooling systems to mitigate the consequences of a UFSAR Chapter 15 accident. This system also provides borated makeup water for the spent fuel pool. The system can remove impurities from the refueling cavity and transfer canal during refueling, and it can clean the refueling water storage tank water following refueling. The refueling water system provides a means of transferring the final 30 percent of the refueling water between the refueling cavity and the refueling water storage tank. It also provides a secondary means of filling the refueling cavity from the refueling water storage tank. The Catawba refueling water system provides an adequate supply of borated water to the emergency core cooling system and containment spray system in order to mitigate the consequences of a design basis event. The refueling water system, along with the safety injection system, residual heat removal system, and CVCS function together to form the emergency core cooling system.

3.2.6.1.1 Aging Effects

Table 3.2-6 of the LRA identifies the following components that will require aging management: expansion joints, refueling water storage tanks, piping, tubing, and valve bodies. The applicant identified stainless and carbon steels as the materials of construction for the refueling water system components. Loss of material was identified as an applicable aging effect for carbon steel materials exposed to ventilation, yard, and borated water environments. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to an internal environment of borated water.

3.2.6.1.2 Aging Management Programs

The LRA identifies the following four aging management programs that will manage the aging effects of the refueling water system:

- Chemistry Control Program
- Borated Water Systems Stainless Steel Inspection
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection

Appendix B of the LRA contains a detailed description of those four aging management programs. The LRA cites these programs as methods to manage aging effects of the refueling water system components in applicable environments

*3.2.6.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed Section 3.2 of the LRA. The purpose of the review was to determine whether the applicant will adequately manage the aging effects of the refueling water system while maintaining the current licensing basis of the system's intended function.

3.2.6.2.1 Aging Effects

The LRA includes a summary of the results of the aging management review for the refueling water system. The results are presented in table 3.2-6 of the LRA. The following list summarizes the materials of construction, the internal/external environments, and aging effects for the refueling water system:

- stainless steel in yard/ventilation/sheltered/reactor building environments — no aging effects
- stainless steel in borated water environment — loss of material and cracking
- carbon steel in ventilation environment — loss of material
- carbon steel in yard environments — loss of material
- carbon steel in borated water environment — loss of material

No aging effects were identified for expansion joints, piping, tubing, the refueling water storage tank, and valve bodies made of stainless steel in yard, sheltered, reactor building, or ventilation environments. Austenitic stainless steel materials are designed to be corrosion resistant in dry or moist air environments. Cracking and corrosion, therefore, generally have not been a problem for austenitic stainless steel components in these environments. The applicant, therefore, did not identify any applicable aging effects for the surfaces of stainless steel components exposed to the above identified environments.

The applicant identified loss of material and cracking as aging effects on stainless steel in the borated water environment. Loss of material and cracking of stainless steel in this environment are possible aging effects under certain conditions. Industry experience indicates that the presence of halogens in excess of 150 ppb, oxygen in excess of 100 pbb, and temperature in excess of 200 °F in stagnant or low flow conditions can lead to loss of material and cracking. Therefore, the applicant will use the Chemistry Control Program and the Borated Water Systems Stainless Steel Inspection program to manage the loss of material and cracking in the borated water environment.

The applicant identified loss of material as an aging effect on the carbon steel refueling water storage tank in a ventilation and yard environment. Loss of material of carbon steel materials by corrosion may occur in moist air environments and, therefore, may be an applicable aging effect. In addition, borated water leaks from other plant systems may also cause loss of material of carbon steel components. The applicant will use the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection and the Inspection Program for Civil Engineering Structures and Components to manage the loss of material associated with the carbon steel refueling water storage tank.

The applicant identified loss of material as an aging effect on the carbon steel refueling water storage tank in the borated water environment. Loss of material of carbon steel materials by boric acid corrosion may occur in borated water environments and, therefore, may be an applicable aging effect. The applicant will use the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection to manage the loss of material associated with the carbon steel refueling water storage tank.

The aging effects identified in LRA Table 3.2-6 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.6.2.2 Aging Management Programs

The applicant identified the following four aging management programs that will manage the aging effects of the refueling water system:

- Chemistry Control Program
- Borated Water Systems Stainless Steel Inspection Program
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection Program

The Chemistry Control Program, Borated Water Systems Stainless Steel Inspection program, and Inspection Program for Civil Engineering Structures and Components, are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection program follows:

Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection

The applicant developed the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection program to manage the potential aging of the carbon steel refueling water storage tanks at McGuire. The internal surfaces of the carbon steel tanks are coated with a phenolic epoxy coating to prevent borated water and air from contacting the internal surfaces. This program manages loss of material of the tanks by managing the condition of the internal coating. This program is only applicable to McGuire.

In Section B.3.24 of LRA Appendix B, the applicant described the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection program. The purpose of the program is to manage loss of material of the internal surfaces of the carbon steel refueling water storage tanks. The internal carbon steel surfaces of the refueling water storage tank are coated with a phenolic epoxy paint that prevents borated water and air from contacting the internal surfaces. Continued presence of an intact coating precludes loss of material that could lead to loss of pressure boundary function. This preventive maintenance activity inspects the internal coating of the refueling water storage tanks to check the condition of the coating and to identify coating failures. This program is only applicable to McGuire.

The staff's evaluation of the Preventive Maintenance Activities — Refueling Water Storage Tank 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.

[Program Scope] The applicant defined the scope of the Preventive Maintenance Activities — Refueling Water Storage Tank Internal Coating Inspection program as the internal surface of the McGuire carbon steel refueling water storage tanks. The comparable refueling water storage tanks at Catawba are constructed of stainless steel and are managed by the Borated Water Systems Stainless Steel Inspection (Section B.3.4 of LRA Appendix B) and the Chemistry Control Program (Section B.3.6 of LRA Appendix B).

The staff finds the scope of this aging management program to be acceptable because it includes the tanks that may be subject to coating failure. Limiting the inspection to the refueling water storage tanks at McGuire is acceptable because the corresponding tanks at Catawba are constructed of different materials and are covered by other programs.

[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 inspection program is intended to identify potential problems, such that corrective action may be taken prior to loss of component function, and that there is no need for preventive actions.

[Parameters Monitored or Inspected]  The program inspects the phenolic epoxy paint for signs of blistering, chipping, peeling, and missing paint, as well as signs of corrosion of the underlying carbon steel tank.  The staff finds the parameters inspected to be acceptable since the inspections are capable of identifying signs of coating damage or deterioration, such that corrective actions can be taken prior to loss of component function.

[Detection of Aging Effects]  The program uses visual inspection to identify blistering, chipping, peeling, and missing paint, as well as signs of corrosion of the underlying carbon steel tank. The staff concludes that these inspections are capable of identifying loss of integrity of the coating and loss of material of the tank prior to loss of the component intended function.

[Monitoring and Trending]  Section B.3.24.2 of LRA Appendix B states that the refueling water storage tank's internal phenolic epoxy paint will be visually inspected every 10 years using an underwater video camera.  The inspection looks for signs of blistering, chipping, peeling, and missing paint, as well as signs of corrosion of the underlying carbon steel tank.  Detection of defects in the internal coating results in draining of the tank for further inspection and evaluation of the defects.  No actions are taken as part of this activity to trend inspection results.

The staff finds that the monitoring is appropriate for the scope of this inspection.  Since the coating is in an area where radiation and thermal conditions are low, and degradation of the coating, is a slow process, the 10-year frequency is acceptable.  The staff finds that the inspection will provide an indication of the condition of the tank coating and is based on methods that are common in the industry.  The staff concurs that trending is not required since the inspection frequency is not conducive to trending.

[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 tank surfaces.  The staff agrees that because the visual inspections are capable of detecting degradation of the coating surfaces, and the approach is consistent with industry practices, the acceptance criteria are acceptable.

[Operating Experience]  The applicant stated that the internal surfaces of the refueling water storage tanks for McGuire were inspected during recent outages using an underwater camera. The inspection revealed some second coating blistering.  The applicant drained the tanks, visually inspected, and repainted in the necessary locations.  The applicant stated that no bare metal was exposed as a result of the blistering because a layer of coating remained in the blistered location.  The applicant observed during these inspections that the submerged portion of the tanks showed little to no degradation.  However, the roof, which is not a part of the pressure boundary of the tank, did show evidence of coating concerns and was blasted and repainted in several locations.

The staff finds that the operating experience with program indicates that the activities will be effective in managing loss of material of the tanks by maintaining the effectiveness of the internal coatings.  Because of the effectiveness of the inspections, as noted in the operating experience, the staff concludes that the program can reasonably be expected to maintain the tank integrity through the period of extended operation.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.20.2, the applicant provided a proposed new UFSAR section for McGuire. The staff reviewed this material and found it to be consistent with the material provided in Appendix B. Therefore, it is acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.24.2 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, the staff finds that there is reasonable assurance that the aging effect of loss of material of the McGuire refueling water storage tanks 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).

Based on its review of Table 3.2-5 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the refueling water system, and that there is reasonable assurance that the intended functions of the refueling water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.2.6.3 Conclusions*

The staff reviewed the information in Section 3.2, “Aging Management of Engineered Safety Features,” of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant’s characterization of the aging effects associated with the refueling water system is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the refueling water system, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.7 Residual Heat Removal System

#### *3.2.7.1 Technical Information in the Application*

The applicant described its AMR for the residual heat removal (RHR) system in Section 3.2 of the LRA. The RHR system transfers heat from the RCS to the component cooling system to reduce the temperature of the reactor coolant to the cold shutdown temperature at a controlled rate during the second part of unit cooldown, and maintains this temperature until the unit is started up. The RHR system also serves as part of the emergency core cooling system during the injection and recirculation phases of small-break and large-break loss of coolant accidents. The McGuire and Catawba UFSARs, Section 6.3, Emergency Core Cooling System, provide additional information concerning the RHR system. The mechanical components, component functions, and materials of construction for the RHR system are listed in Table 3.2-7.

3.2.7.1.1 Aging Effects

In Table 3.2-7 of the application, the applicant identifies the following components that are subject to an AMR: heat exchangers and their subcomponents, piping, orifices, tubing, pump casings, and valve bodies. In this table, the applicant identifies that these components are fabricated from stainless steel materials, with the exception of the RHR heat exchanger shells and RHR pump seal water shells, which are fabricated from carbon steel.

Loss of material was identified as an applicable aging effect for carbon steel materials exposed to treated water and sheltered environments. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to borated and treated water environments and for carbon steel materials exposed to a treated water environment.

3.2.7.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed for the RHR components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The applicant stated that it will use the Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) and the Inspection Program for Civil Engineering Structures and Components (Section B.3.21 of LRA Appendix B) to manage loss of material in carbon steel RHR components exposed to sheltered air environments. The applicant also stated that it will use the Chemistry Control Program (Section B.3.6 of LRA Appendix B) to manage loss of material and cracking in stainless steel RHR components that are exposed to borated or treated water environments, and loss of material and cracking in carbon steel components that are exposed to treated water environments.

*3.2.7.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 (including Table 3.2-7), and pertinent sections of LRA Appendices A and B, to ascertain that the effects of aging will be adequately managed, so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.7.2.1 Aging Effects

Table 3.2-7 of the application identifies which of these aging effects are applicable to the specific RHR components identified in the table as being within the scope of license renewal. Specifically, Table 3.2-7 identifies that the following aging effects are applicable to the material-environment combinations for the RHR components:

- stainless steel components exposed to borated or treated water environments — loss of material and cracking
- stainless steel components in contact with sheltered or reactor building environments — no

aging effects identified

- carbon steel components exposed to sheltered environments — loss of material
- carbon steel RHR pump seal water components exposed to treated water environments — loss of material
- carbon steel RHR heat exchanger components exposed to treated water environments — loss of material and cracking

Industry experience and experimental data have demonstrated that austenitic stainless steel materials may be susceptible to stress corrosion cracking or loss of material (as a result of pitting or general corrosion) when exposed to borated water solutions. Elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increase the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel RHR components in contact with borated water solutions. The applicant has appropriately identified these aging effects as being applicable to stainless steel RHR components whose internal surfaces are exposed to borated water. This determination is acceptable to the staff.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, cracking and corrosion generally have not been a problem for austenitic stainless steel components in sheltered or reactor building environments. Therefore, the applicant has not identified any applicable aging effects for the surfaces of stainless steel RHR components exposed to these types of air environments. Based on these considerations, the staff finds the applicant's identification of the aging effects for stainless steel RHR components to be acceptable.

Use of raw, untreated water in heat exchanger tubes may be prone to biological fouling that could impede the heat exchange functions of the tubes over time. However, raw, untreated water is not the cooling medium for the tubing, the annulus regions of the RHR heat exchangers, or the RHR pump seal water heat exchangers. Therefore, the applicant has not identified fouling as an applicable effect for these heat exchangers. The carbon steel RHR heat exchanger shells are in contact with sheltered air environments on their external surfaces, and treated water on their internal surfaces. The internal surfaces of the shell may be subject to loss of material through general corrosion (rusting) when exposed to wet environments. The applicant has also identified cracking as an additional aging effect that requires management for the internal surfaces of the RHR heat exchanger shells.

By letter dated January 23, 2002, the staff informed the applicant that the internal surfaces of the carbon steel residual RHR heat exchanger shells and RHR pump seal water heat exchanger shells are both exposed to treated water environments, and requested, in RAI 3.2-4, the applicant to clarify, either by reference to appropriate information in the application or by discussion, why cracking is identified as an applicable aging effect for the RHR heat exchanger shells but not for the RHR pump seal water heat exchanger shells. In its response dated April 15, 2002, the applicant stated that cracking should have been also identified for the internal surfaces of the RHR pump seal water heat exchangers shells, and that the Chemistry Control Program is credited as the aging management program for managing the cracking. The applicant submitted a revised Table 3.2-7 AMR for the RHR pump seal water heat exchangers shells to replace the corresponding entry in the LRA. The applicant's resolution of RAI 3.2-4 is, therefore, acceptable to the staff.

Further, the external surfaces of these components may be subject to corrosion if leaks develop. Therefore, the applicant has appropriately identified that loss of material is an applicable aging effect for the surfaces of the RHR heat exchangers and ND pump seal water heat exchangers shells that are exposed to treated water and sheltered air environments. This determination is acceptable to the staff.

The aging effects identified in LRA Table 3.2-7 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.7.2.2 Aging Management Programs

Table 3.2-7 of the LRA states that the following programs and activities are credited for managing the aging effects attributed to the RHR components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-7, the staff concludes that the above identified AMPs will effectively manage the aging effects of the RHR system, and that there is reasonable assurance that the intended functions of the RHR system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.2.7.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the RHR is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the RHR, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.8 Safety Injection System

*3.2.8.1 Technical Information in the Application*

The applicant described its AMR for the safety injection system (SIS) in Section 3.2 of the LRA. The SIS constitutes a major portion of the ECCS. Along with the residual heat removal, chemical and volume control, and refueling water systems, the SIS provides emergency cooling water to the reactor core in the event of a break in either the primary (reactor coolant) or secondary (steam) systems. The three primary functions of the ECCS are (1) to remove stored (sensible) and fission product decay heat, (2) to control reactivity, and (3) to preclude reactor vessel boron precipitation. The SIS supports each of these functions. Section 6.3, “Emergency Core Cooling System,” of the McGuire and Catawba UFSARs provides additional information concerning the SIS. The mechanical components, component functions, and materials of construction for the SIS are listed in Table 3.2-8 of the LRA.

3.2.8.1.1 Aging Effects

In Table 3.2-8 of the LRA, the applicant identifies the following components that are subject to an AMR: pump casings, piping, orifices, accumulators, tubing, and valve bodies. In the table, the applicant identifies that all of these components are fabricated from stainless steel materials, with the following exceptions:

- A small portion of SIS pipe is fabricated from carbon steel.
- SIS accumulators are fabricated from carbon steel with an internal stainless steel cladding.
- Some SIS valve bodies are fabricated from carbon steel.

Loss of material was identified as an applicable aging effect for carbon steel materials exposed to the reactor building and sheltered external environments. Loss of material and cracking were identified as applicable aging effects for stainless steel materials exposed to a borated water environment.

3.2.8.1.2 Aging Management Programs

The applicant credits the following programs and activities for managing the aging effects attributed for the SIS components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The applicant stated that it will use the Fluid Leak Management Program (Section B.3.15 of LRA Appendix B) and the Inspection Program for Civil Engineering Structures and Components (Section B.3.21 of LRA Appendix B) to manage loss of material in carbon steel SIS components exposed to sheltered air and reactor building environments. The applicant also stated that it will use the Chemistry Control Program (Section B.3.6 of LRA Appendix B) to manage loss of material and cracking in stainless steel SIS components that are exposed to treated water environments.

*3.2.8.2 Staff Evaluation*

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2 (including Table 3.2-8), and pertinent sections of Appendices A and B to the LRA, to ascertain that the effects of aging will be adequately managed, so that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.8.2.1 Aging Effects

The LRA includes a summary of the results of the AMR for the SIS system. The results are presented in table 3.2-8 of the LRA. The following list summarizes the materials of construction, the internal/external environments, and aging effects for the SIS:

- stainless steel components exposed to borated water environments — loss of material and cracking
- carbon steel components whose external surfaces are exposed to reactor building and sheltered environments — loss of material

Industry experience and experimental data have demonstrated that austenitic stainless steel materials may be susceptible to stress corrosion cracking or loss of material (as a result of pitting or general corrosion) when exposed to borated water. Elevated levels of oxidizing impurity species (i.e., oxygen, sulfates, halides, etc.) increase the potential for these aging effects to occur. These aging effects are therefore applicable to the stainless steel SIS components in contact with borated water solutions. The applicant has appropriately identified these aging effects as being applicable to stainless steel SIS components whose internal surfaces are exposed to borated water. This determination is acceptable to the staff.

Austenitic stainless steel materials are designed to be corrosion resistant in both dry or moist air environments. Therefore, cracking and corrosion generally have not been a problem for austenitic stainless steel components in air-gas, sheltered, or reactor building environments. The applicant, therefore, has not identified any applicable aging effects for internal surfaces of stainless steel SIS components exposed to an air-gas environment, or the external surfaces of stainless steel SIS components exposed to sheltered air or reactor building air environments. Based on these considerations, the staff finds the applicant's identification of the aging effects for stainless steel SIS components to be acceptable.

The carbon steel SIS piping and valve body components are in contact with air-gas environments on their internal surfaces, and either sheltered air or reactor building environments on their external surfaces. Carbon steels may be prone to loss of material by corrosion when exposed to moist air environments. Therefore, loss of material may be an applicable aging effect for the surfaces of carbon steel SIS components that are exposed to sheltered or reactor building air environments.

By letter dated January 28, 2002, the staff asked, in RAI 3.2-5, the applicant to clarify, either by reference to appropriate information in the application or by discussion, why loss of material is identified as an applicable aging effect for the carbon steel SIS piping that is exposed sheltered air, but not for the carbon steel SIS valve bodies that are exposed to the same environment. In its response, dated May 15, 2002, the applicant stated that the aging effects for carbon steel valve bodies exposed to sheltered air environments should be identical to those for carbon steel piping exposed to the same environment and that, therefore, loss of material should have been identified for the carbon steel valve bodies exposed externally to sheltered air environments. The applicant provided an amended entry for the SIS carbon steel valve bodies exposed internally to the air-gas environment and externally to the sheltered air environment that is consistent with the corresponding entry for carbon steel piping in Table 3.2-8 of the application. This is acceptable to the staff and resolves the staff's issue identified in RAI 3.2-5.

The carbon steel surfaces of the accumulators may be prone to loss of material by corrosion if borated water leaks onto the external surfaces of the accumulators. The applicant has appropriately accounted for this as an additional mechanism that can result in loss of material for the carbon steel surfaces of the accumulators. The applicant has not identified any applicable aging effects for the surfaces of carbon steel SIS components that are exposed to air-gas environments. The air-gas environments are compressed dry gaseous environments. Loss of material and cracking generally have not been a problem for carbon steel surfaces that are exposed to air-gas environments. Based on the considerations discussed in this section, the staff considers the applicant's aging effect analysis for the carbon steel SIS components to be acceptable.

The aging effects identified in LRA Table 3.2-8 are consistent with industry experience for the combinations of materials and environments listed. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.2.8.2.2 Aging Management Programs

Table 3.2-8 of the LRA states that the following aging management programs are credited for managing the aging effects attributed to the SIS components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.2-8, the staff concludes that the above identified AMPs will effectively manage the aging effects of the SIS, and that there is reasonable assurance that the intended functions of the SIS will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.2.8.3 Conclusions*

The staff reviewed the information in Section 3.2, "Aging Management of Engineered Safety Features," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's characterization of the aging effects associated with the SIS is consistent with published literature and industry experience. The staff further concludes that the applicant has appropriate aging management programs to effectively manage the aging effects of the SIS, and that there is reasonable assurance that the intended functions of the system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.2.9 Containment Air Return Exchange and Hydrogen Skimmer Systems — Supplemental Evaluation

In a letter dated January 23, 2002, the staff requested, in RAI 2.3.2.3-2, the applicant to indicate whether or not the McGuire and Catawba containment hydrogen analyzers and their subcomponents should be included within the scope of license renewal. In its response to RAI 2.3.2.3-2, dated April 15, 2002, the applicant concurred with the staff that the passive mechanical components for the McGuire and Catawba hydrogen analyzers associated with the hydrogen skimmer systems should be within the scope of license renewal. This section documents the staff's evaluation of the AMR results that were provided for the additional components brought into the scope of license renewal as a result of this RAI.

#### *3.2.9.1 Technical Information in the Application*

The containment air return exchange and hydrogen skimmer systems provide the following safety-related functions for the McGuire and Catawba nuclear plants: (1) maintain containment pressure less than the design pressure during any high energy line break (HELB), (2) ensure hydrogen concentration remains less than the flammability limit during a loss-of-coolant-accident (LOCA), and (3) maintain containment isolation integrity for the system piping penetrating the containment. McGuire and Catawba UFSAR Sections 6.2, Containment Systems, provide additional information concerning the McGuire and Catawba containment air return exchange and hydrogen skimmer systems. The mechanical components, component functions, and materials of construction for the McGuire containment air return exchange and hydrogen skimmer systems are listed in Table 3.2-3 of the LRA.

##### 3.2.9.1.1 Aging Effects

In the Table attached to its response to RAI 2.3.2.3-2, the applicant stated that the major flowpaths for the McGuire and Catawba hydrogen analyzers include the following components that are subject to AMRs: tubing and valve bodies for McGuire and Catawba (and McGuire-specific piping). In this table, the applicant identifies that all of these components are fabricated from stainless steel materials. The applicant identifies that these components are subject to any of the following environments:

- ventilation air
- sheltered air
- reactor building air

The applicant did not identify any additional aging affects associated with the passive mechanical hydrogen analyzer components brought within the scope of license renewal.

3.2.9.1.2 Aging Management Programs

The applicant did not identify any aging management programs necessary for the passive mechanical hydrogen analyzer components brought within the scope of license renewal.

*3.2.9.2 Staff Evaluation*

3.2.9.2.1 Aging Effects

As summarized in the application, the applicant stated the sheltered and reactor building environments are moist air environments; however, during normal system operations of the systems, any components whose external surface temperatures are the same as or higher than the ambient temperature conditions for these environments are expected to be dry. The applicant states that the ventilation air environment is ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy.

Since the internal and external environmental surface conditions for these components should be under either dry or controlled air conditions, the staff concurs that no aging effects are applicable for the stainless steel tubing and valves (and for McGuire, the McGuire-specific stainless steel piping) associated with the hydrogen analyzers.

3.2.9.2.2 Aging Management Programs

Since the environmental surface conditions for these components should be under either dry or controlled air conditions, and no aging effects are applicable for the stainless steel tubing and valves (and for McGuire, the McGuire-specific stainless steel piping) associated with the hydrogen analyzers, the staff concurs that no aging management programs are necessary for the passive mechanical hydrogen analyzer components within the scope of license renewal.

*3.2.9.3 Conclusions*

The staff reviewed the information in Section 3.2 of the LRA and the table attached to the applicant's response to RAI 2.3.2.3-2, dated April 15, 2002, as the information pertains to the AMRs for the additional hydrogen analyzers components brought within the scope of license renewal. On the basis of its review, the staff concludes that the applicant has demonstrated that there are not any aging effects associated with the additional hydrogen analyzers components brought within the scope of license renewal, and that the hydrogen analyzer components brought within the scope of license renewal need not be managed to provide reasonable assurance that the system components 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).

### 3.2.10 Aging Management Review for Closure Bolting in Engineered Safety Features

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to an AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 of the LRA do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

*3.2.10.1 Aging Effects*

The applicant indicated that non-Class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures, and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure in accordance with the design codes and, therefore, are not subject to an aging management review.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid, while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system that are of the same material and exposed to the same environment. Programs for the system (i.e., Chemistry Control Program and Fluid Leak Management Program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-Class 1 bolted closures are loss of material of carbon and low-alloy steel, and cracking of carbon, low-alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, Duke determined the following are the aging effects requiring management for carbon and low-alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments identified.

*3.2.10.2 Aging Management Programs*

The applicant identified the following two aging management programs that will manage the aging effects of closure bolting:

- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The applicant indicated that the Fluid Leak Management Program will manage loss of material of non-Class 1 bolted closures in the reactor and auxiliary buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in Appendix B, Section B.3.15 of the LRA for McGuire and Catawba.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-Class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-Class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in Appendix B, Section B.3.21 of the LRA for McGuire and Catawba.

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for non-Class 1 closure bolting. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

*3.2.10.3 Conclusions*

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with non-Class 1 bolting will be adequately managed, so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.3 Auxiliary Systems

The applicant described its AMR of the Auxiliary Systems in Section 2.3.3, "Auxiliary Systems," and in Section 3.3, "Aging Management of Auxiliary Systems." Appendices A and B to the LRA also contain supplementary information related to the AMR of the auxiliary systems. The staff reviewed this section of the application in accordance with Chapter 3 of the Standard Review Plan for License Renewal (NUREG-1800) to determine whether the applicant provided adequate information to meet the requirements of 10 CFR Part 54 for managing the aging effects of the Auxiliary Systems for license renewal.

In LRA Section 2.1, "Scoping and Screening Methodology," the applicant described the method used to identify the structures and components (SCs) that are within the scope of license renewal and subject to an AMR. The applicant identified and listed the structures in LRA Section 2.4, "Scoping and Screening Results: Structures." The staff's evaluation of the scoping methodology and the structures included within the scope of license renewal, and subject to an AMR, is documented in Sections 2.1 and 2.4 of this SER, respectively.

Section 3.3 of the LRA defined the external and internal environments applicable to the auxiliary systems as follows—

- Air-Gas — Compressed air is ambient air that has been filtered and compressed for use in plant equipment. Compressed air may be either dry or oiled. Compressed gasses include carbon dioxide, hydrogen, nitrogen, freon, or refrigeration gasses used to replace freon due to environmental concerns.
- Borated Water — Borated water is demineralized water treated with boric acid.
- Embedded Environment — A component encased in concrete is in an embedded environment. The concrete forms a tight seal around the external surfaces of the component.
- Oil and Fuel Oil — Lubricating oil is an organic fluid used to reduce friction between moving parts. Fuel oil is the fuel used for the emergency diesel generators.
- Raw Water — Raw water is water from a lake, pond, or river that has been rough-filtered and possibly treated with a biocide.
- 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.
- Sheltered environment — The ambient conditions within the sheltered environment may or may not be controlled. The sheltered environment atmosphere is a moist air environment. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.
- 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.
- Underground Environment — Components in an underground environment are in contact with soil and possibly groundwater. Components located underground are normally coated and wrapped to prevent the soil and groundwater from contacting the surface of the component.
- Ventilation — Ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy.

- Yard — Yard environment is a moist air environment in which equipment is exposed to heat, cold, and precipitation.

In Appendix A of the LRA, "Updated Final Safety Analysis Report (UFSAR) Supplement," the applicant provided a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). The applicant provided a more detailed description of these AMPs for the staff to use in its evaluation in Appendix B to the LRA. In LRA Appendix D, the applicant states that no changes to the McGuire and Catawba Technical Specifications (TS) have been identified. A discussion of the AMR results for each system follows.

### 3.3.1 Auxiliary Building Ventilation System

#### *3.3.1.1 Technical Information in the Application*

The auxiliary building ventilation system is essentially the same, and performs the same function, for McGuire and Catawba. The auxiliary building ventilation system automatically aligns to maintain the ECCS pump rooms at a negative pressure, so that air exhausted from these rooms is filtered prior to being released following a design basis accident (DBA). The ECCS pump rooms include safety injection pumps, residual heat removal pumps, centrifugal charging pumps, and containment spray pumps. The McGuire and Catawba UFSARs provide more detailed descriptions in Sections 9.4.2 and 9.4.3, respectively.

##### 3.3.1.1.1 Aging Effects

Components of the auxiliary building ventilation system are described in Section 2.3.3.1 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-1, pages 3.3-6 through 3.3-10, lists individual components of the system, including the air flow monitors, air handling units, ductwork, filters, demisters, condensers, area heaters, tubing, and valve bodies. Stainless steel components are identified as being subject to ventilation and sheltered environments, and are subject to no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from sheltered and treated water environments. Carbon steel components are also subject to the aging effect of cracking from exposure to a treated water environment. Carbon steel components are also exposed to a gas (Freon-22) environment with no aging effects. Galvanized steel components are identified as being subject to the aging effect of loss of material from the sheltered environment. Copper components are subject to the aging effect of loss of material and fouling from internal surfaces from raw water environments, and external surfaces from loss of material from exposure to sheltered environments. Copper components also are exposed to a ventilation environment with no aging effects. Copper-nickel components are subject to the aging effect of loss of material and fouling from internal surfaces from treated water environments. Copper-nickel components are also exposed to a gas (Freon-22) environment with no aging effects. Brass components are subject to the aging effect of loss of material to external surfaces from sheltered environments. No aging effects are identified to brass components subjected to a ventilation environment.

3.3.1.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the auxiliary building ventilation system:

- Fluid Leak Management Program
- Heat Exchanger Preventive Maintenance Activities — Pump Motor Handling Units
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the auxiliary building ventilation system will be adequately managed by these AMPs during the period of extended operation.

*3.3.1.2 Staff Evaluation*

The applicant described its AMR of the auxiliary building ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the auxiliary building ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.1.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10. During its review, the staff determined that additional information was needed to complete its review and, on January 23, 2002, issued RAI 3.3-1. The staff's evaluation of the applicant's response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER, and is characterized as resolved.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function. The applicant identified cracking and shrinkage of structural sealants in the interface between a structural wall, floor, or ceiling and a nonstructural component (such as a duct, piping, electrical cables, doors, and nonstructural walls) resulting from exposure to ambient conditions as potential aging effects.

The staff finds that the aging effects that result from contact of the auxiliary building ventilation system SSCs to the environments described in LRA Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10, and in correspondence from the applicant, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.1.2.2 Aging Management Programs

LRA Section 2.3.3.1 and Table 3.3-1, pages 3.3-6 through 3.3-10, state that the following aging management programs are credited for managing the aging effects in the auxiliary building ventilation system components:

- Fluid Leak Management Program
- Heat Exchanger Preventive Maintenance Activities — Pump Motor Handling Units
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The Fluid Leak Management Program, Heat Exchanger Preventive Maintenance Activities — Pump Motor Handling Units Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-1, and correspondence from the applicant, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary building ventilation system, and that there is reasonable assurance that the intended functions of the auxiliary building ventilation system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.1.3 Conclusions*

The staff reviewed the information in Section 2.3.3.1 and Table 3.3-1 of the LRA and in correspondence from the applicant . On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary building ventilation system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.2 Boron Recycle System

*3.3.2.1 Technical Information in the Application*

The boron recycle system is essentially the same, and performs the same function, for McGuire and Catawba. The boron recycle system receives borated effluent from the RCS and associated support systems. This borated effluent is demineralized, filtered, and separated into 4 weight percent boric acid and reactor makeup water for reuse. The boron recycle system also provides reactor grade flush water for components in the auxiliary and reactor buildings. The McGuire and Catawba UFSARs provide more detailed descriptions in Sections 9.3.6 and 9.3.5, respectively.

3.3.2.1.1 Aging Effects

Components of the boron recycle system are described in Section 2.3.3.2 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-2, pages 3.3-11 through 3.3-15, lists individual components of the system, including the eductors, filters, flow meters, orifices, pipes, demineralizers, tanks, strainers, tubing, and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of borated and treated water. Exposure of stainless steel to sheltered, air-gas, and reactor building environments have no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from sheltered and treated water environments. Carbon steel is also subject to a air-gas environment with no aging effect.

3.3.2.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the boron recycle system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Flow-Accelerated Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the boron recycle system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.2.2 Staff Evaluation*

The applicant described its AMR of the boron recycle system for license renewal in two separate sections of its LRA, Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the boron recycle system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.2-1, the applicant to indicate if Note (3), which was listed at the back of Table 3.3-2 and implied that portions of the boron recycle system may be subject to alternate wetting and drying, was applicable to any of the components listed in Table 3.3-2. In its RAI, the staff further requested the applicant to explain, if Note (3) did apply, how this environment and associated aging effects are managed in the LRA. In its response dated March 15, 2002, the applicant acknowledged that Note (3) did not apply to the boron recycle system, and that no components of this system are subject to alternate wetting and drying.

By letter dated January 23, 2002, the staff requested, in RAI-3.3.2-2, the applicant to indicate if Note (1), which was listed at the back of Table 3.3-2 and contained a definition for a component function of "HT" (heat transfer), applied to components listed in Table 3.3-2. In its response dated March 15, 2002, the applicant acknowledged that Note (1) did not apply to the boron recycle system, and that no components of this system have a "HT" or "TH" (throttle) function.

Since the system does not have a "HT" or "TH" function, the staff finds that the applicant's response clarifies and satisfactorily resolves this item. The aging effects that result from contact of the boron recycle system SSCs to the environments described in LRA Section 2.3.3.2 and Table 3.3-2, pages 3.3-11 through 3.3-15, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.2.2.2 Aging Management Programs

LRA Table 3.3-2, pages 3.3-11 through 3.3-15, states that the following aging management programs are credited for managing the aging effects in the boron recycle system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Flow-Accelerated Corrosion Program

The Fluid Leak Management Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Flow-Accelerated Corrosion Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the boron recycle system, and that there is reasonable assurance that the intended functions of the boron recycle system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.2.3 Conclusions*

The staff reviewed the information in Section 2.3.3.2 and Table 3.3-2 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the boron recycle system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.3 Building Heating Water System

*3.3.3.1 Technical Information in the Application*

The McGuire building heating water system provides normal heating requirements of the auxiliary building ventilation system, fuel pool ventilation system, containment and in-core instrumentation room purge system, service building ventilation system, and the turbine building heating system. The Catawba building heating water system supplies hot water to the heating coils of various heating, ventilation, and air conditioning (HVAC) units throughout the plant.

For both McGuire and Catawba, the building heating water system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed. All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10CFR 54.4(a)(2).

3.3.3.1.1 Aging Effects

Components of the building heating water system are described in Section 2.3.3.3 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-3, page 3.3-16, lists individual components of the system, including pipes and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of treated water. Exposure of stainless steel to sheltered environments has no associated aging effects. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from a treated water environment. Carbon steel is also subject to an aging effect of loss of material from exposure to sheltered environments.

3.3.3.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the building heating water system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the building heating water system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.3.2 Staff Evaluation*

The applicant described its AMR of the building heating water system for license renewal in two separate sections of its LRA, Section 2.3.3.3 and Table 3.3-3, page 3.3-16. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the building heating water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.3.2.1 Aging Effects

The aging effects that result from contact of the building heating water system SSCs to the environments described in Section 2.3.3.3 and Table 3.3-3, page 3.3-16, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.3.2.2 Aging Management Programs

Section 2.3.3.3 and Table 3.3-3, page 3.3-16, of the LRA state that the following aging management programs are credited for managing the aging effects in the building heating water system:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the building heating water system, and that there is reasonable assurance that the intended functions of the building heating water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.3.3 Conclusions*

The staff reviewed the information in Section 2.3.3.3 and Table 3.3-3, page 3.3-16, of the LRA. On the basis of its review, the staff finds that the applicant has demonstrated that the aging effects associated with the building heating water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.4 Chemical and Volume Control System

*3.3.4.1 Technical Information in the Application*

The CVCS is an integral part of the ECCS and provides high pressure injection and recirculation of borated water to the RCS cold legs following small and large break loss of coolant accidents and main steam line break accidents. The CVCS is also used to provide negative reactivity, by boron injection, to the core. The McGuire and Catawba UFSARs provide more detailed descriptions in Section 9.3.4.

#### 3.3.4.1.1 Aging Effects

Components of the CVCS are described in Section 2.3.3.4 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, list individual components of the system, including pipes, valve bodies, boric acid blenders, filters, tanks, pump casings, meters, resin traps, demineralizers, heat exchangers, orifices, accumulators, stabilizers, spray nozzles, dampeners, and tubing. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of borated and treated water. Exposure of stainless steel to sheltered, gas, reactor building, and ventilation environments has no aging effects. Carbon steel components are subject to the aging effect of loss of material and cracking from the internal environment of treated water. Carbon steel is also subject to an aging effect of loss of material from exposure to sheltered and reactor building environments. Exposure of carbon steel components to an internal gas environment has no aging effect. Cast austenitic stainless steel exposed to a borated environment is subject to the aging effects of cracking and loss of material. Exposure of cast austenitic stainless steel to a reactor building environment has no aging effect identified.

#### 3.3.4.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the CVCS:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the CVCS will be adequately managed by these aging management programs during the period of extended operation.

### *3.3.4.2 Staff Evaluation*

The applicant described its AMR of the CVCS for license renewal in three separate sections of its LRA, Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the CVCS will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.3.4.2.1 Aging Effects

The aging effects that result from contact of chemical and volume control SSCs to the environments described in LRA Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.4.2.2 Aging Management Programs

LRA Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37, state that the following aging management programs are credited for managing the aging effects in the CVCS:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Tables 3.3-4 and 3.3-5, the staff concludes that the above identified AMPs will effectively manage the aging effects of the CVCS, and that there is reasonable assurance that the intended functions of the CVCS will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.4.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.4 and Tables 3.3-4 and 3.3-5, pages 3.3-17 through 3.3-37. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the CVCS will be adequately managed, so that there is reasonable assurance that the system components 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).

## 3.3.5 Component Cooling System

*3.3.5.1 Technical Information in the Application*

The Component Cooling System is essentially the same, and performs the same function, for McGuire and Catawba. The component cooling system is a closed loop system that maintains cooling to the essential header components, as required for plant conditions; maintains an intermediate system pressure boundary between the RCS and the nuclear service water system to prevent potential radioactive release; provides containment isolation; and maintains containment closure for shutdown. The McGuire and Catawba UFSARs provide more detailed descriptions in Sections 9.2.4 and 9.2.2, respectively.

3.3.5.1.1 Aging Effects

Components of the component cooling system are described in LRA Section 2.3.3.5 as being within the scope of license renewal and subject to an AMR. LRA Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83, list individual components of the system, including pipes, valve bodies, flex hoses, heat exchangers, condensers, coolers, tanks, orifices, pump casings, and tubing. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal and external environments of borated, treated water, and treated water (alternate wet/dry). Exposure of stainless steel to sheltered, reactor building, and ventilation environments have no aging effects. Carbon steel components are subject to the aging effect of loss of material and cracking from the internal environment of treated water. Carbon steel is also subject to an aging effect of loss of material to internal surfaces from raw water, and external surfaces from exposure to sheltered and reactor building environments. Exposure of carbon steel components to an oil environment has no aging effect. Inconel 625 exposed to a treated water environment is subject to the aging effects of cracking and loss of material. Exposure of Inconel 625 to reactor building environment has no aging effect. Exposure of cast austenitic stainless steel to a reactor building environment has no aging effect identified. Internal surfaces of admiralty brass components are identified as being subject to the aging effects of fouling and loss of material from being exposed to a raw water environment. External surfaces of admiralty brass components are subject to the aging effects of cracking, fouling, and loss of material from exposure to a treated water environment. Copper alloy components are identified as being subject to the aging effects of cracking and loss of material from the treated water environment. Internal surfaces of copper-nickel components are subject to the aging effects of cracking, loss of material, and fouling from exposure to treated water. External surfaces of copper-nickel components exposed to oil and ventilation environments demonstrate no aging effects, while those exposed to sheltered environments experience the aging effect of loss of material.

3.3.5.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the component cooling system:

- Performance Testing Activities — Component Cooling Heat Exchanger
- Heat Exchanger Preventive Maintenance Activities — Component Cooling
- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Liquid Waste System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the component cooling system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.5.2 Staff Evaluation*

The applicant described its AMR of the component cooling system for license renewal in two separate sections of its LRA, Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the component cooling system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.5.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83. During its review, the staff determined that additional information was needed to complete its review. Tables 3.3-6 and 3.3-7 (page 3.3-38 and 3.3-83), indicate that certain reactor coolant (NC) pump motor upper and lower bearing cooler components have a treated water internal environment with an oil external environment. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, the applicant to indicate where in the LRA the aging effect of loss of material to these components with oil systems subject to water contamination were addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, oil cooler tube failures that could introduce water into a lube oil environment were not assumed.

The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item. The aging effects that result from contact of component cooling SSCs to the environments described in LRA Section 2.3.3.5 and Tables 3.3-6 and 3.3-7, pages 3.3-38 through 3.3-83, are consistent with industry experience for these combinations of materials and environments. The staff finds that the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.5.2.2 Aging Management Programs

Tables 3.3-6 and 3.3-7 of the LRA state that the following aging management programs are credited for managing the aging effects in the component cooling system:

- Performance Testing Activities — Component Cooling Heat Exchanger
- Heat Exchanger Preventive Maintenance Activities — Component Cooling
- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Liquid Waste System Inspection

The Fluid Leak Management Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Liquid Waste System Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in

Section 3.0 of this SER. The staff's evaluation of the Performance Testing Activities — Component Cooling Heat Exchanger Program and the Heat Exchanger Preventive Maintenance Activities — Component Cooling program follows.

<u>Performance Testing Activities — Component Cooling Heat Exchangers</u>

The applicant described its component cooling heat exchangers performance testing activities in Section B.3.17.1.1 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

In Section B.3.17.1.1 of LRA Appendix B, the applicant stated the purpose of the component cooling heat exchangers performance testing activities and the methods used to monitor and trend the performance of the heat exchangers. The purpose of this program is to manage fouling of admiralty brass and stainless steel heat exchanger tubes that are exposed to raw water. This is a performance monitoring program that monitors specific component parameters to detect the presence of fouling which can affect the heat transfer function of the component.

The staff's evaluation of the Performance Testing Activities — Component Cooling Heat Exchangers 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:

[Program Scope] The scope of this program includes the McGuire and Catawba component cooling heat exchanger tubes. The staff finds the scope of the program to be acceptable because the information in the application, and in the applicant's response to the staff's RAI, is comprehensive in that it includes the components of the component cooling heat exchangers that are subject to an AMR.

[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. This is a performance monitoring activity. The staff considers the performance testing activities as a means of detecting, not preventing aging. Therefore, the staff agrees that there are no preventive measures to be taken or required.

[Parameters Monitored or Inspected] The Performance Testing Activities — Component Cooling Heat Exchangers involves monitoring of flow capacity by performance of a differential pressure test to provide an indication of fouling. By letter dated January 28, 2002, the staff requested, in RAI B.3.17-1, additional information from the applicant regarding the flow rates in the component cooling heat exchangers and the susceptibility to flow-induced corrosion. In its response dated March 15, 2002, the applicant indicated that normal or design velocities were reviewed for each heat exchanger to determine whether flow-induced corrosion is applicable. The applicant found that flow-induced corrosion is not an applicable aging effect for any heat exchanger subject to an aging management review. The staff agreed that the differential pressure test is an appropriate method to monitor system performance because it provides a clear indication of tube fouling.

[Detection of Aging Effects]  The applicant described the performance testing activities that will be used to detect fouling prior to loss of component heat transfer function.  The staff agrees that this testing is appropriate because it will provide information to the applicant prior to loss of component function.

[Monitoring and Trending]  The applicant stated that the Performance Testing Activities — Component Cooling Heat Exchangers program measures the pressure drop through the heat exchanger tubes.  An increase in pressure drop indicates the presence of fouling.  At McGuire, the applicant indicated that the pressure drop through the heat exchanger tubes is continuously monitored, and the pressure drop evaluated against the acceptance criteria.  Because the parameter is continuously monitored, the staff finds this acceptable.

At Catawba, a periodic differential pressure test is performed.  The test results are trended against a baseline value for indication of tube cleanliness.  The frequency of testing at Catawba permits the results of the testing to be trended to determine when corrective action is required. The staff reviewed the monitoring and trending activities that are relied on by the applicant and found that they are consistent with current industry practice and, therefore, are acceptable to the staff.

[Acceptance Criteria]  At McGuire, where the differential pressure is continuously monitored, the acceptance criteria are in the form of alarm points.  An alarm point is provided for high differential pressure and for a high-high differential pressure.  At Catawba, the acceptance criterion is in the form of a flow resistance factor value.  The acceptable value at both plants is based on a design resistance factor for “clean” heat exchanger tubes.  The staff finds both acceptance criteria to be appropriate because they provide the operators with information that will allow action to be taken prior to loss of component function.

[Operating Experience]  The applicant reported that operating experience associated with the Performance Testing Activities — Component Cooling Heat Exchangers has demonstrated that monitoring of flow through the heat exchangers provides adequate information on the extent of fouling present in the tubes to predict when corrective action is required.  Corrective action, in the form of flushing or tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity.  The applicant's experience has demonstrated that both of these techniques permit the fouling to be monitored, and any required corrective actions to be performed before the heat transfer function degrades below acceptable limits.  The results of trending (at Catawba) for the heat exchanger tube fouling have resulted in the performance of cleaning activities.  The applicant has tested different types of cleaning mechanisms (i.e., darts, brushes, high pressure water laze, etc.) in order to maximize the effectiveness of the cleaning.  Cleaning activities have restored the condition of the tube surfaces by removal of fouling materials.  The applicant has trended the length of time between required cleaning in order to determine the most effective cleaning process and methods.

[McGuire-Specific Operating Experience]  The applicant stated that experience with flow monitoring at McGuire has indicated that the alarm point setting permits action before the differential pressure limit is reached.  The applicant reported that the combination of high velocity flushes and better cleaning during outages have almost eliminated on-line cleaning of the heat exchanger tubes. On the basis of the McGuire operating experience, the staff finds that the performance testing activities are capable of identifying and correcting fouling conditions before loss of component function.

[Catawba-Specific Operating Experience] The applicant stated that experience with the flow tests at Catawba has indicated that the stainless steel tubes foul slightly faster than the original brass tubes. High velocity flushing every 6 to 8 weeks has been used by the applicant and been found to be potentially effective in reducing fouling and prolonging heat exchanger service between tube cleaning. The staff finds that the applicant's heat exchanger performance monitoring activities for the component cooling heat exchangers operating experience have demonstrated the effectiveness of the program in identifying and correcting fouling prior to loss of component intended function.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.1 ,and LRA Appendix A-2, Section 18.2.12.1, the applicant has provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17.1.1 and is, therefore, acceptable.

In conclusion, the staff reviewed the information in Section B.3.17.1.1 of the LRA and the applicant’s response to the staff’s request for additional information. On the basis of its 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 Performance Testing Activities — Component Cooling Heat Exchangers 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).

<u>Heat Exchanger Preventive Maintenance Activities — Component Cooling</u>

The applicant described its Heat Exchanger Preventive Maintenance Activities — Component Cooling program in Section B.3.17.1.2 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

Section B.3.17.1.2 of LRA Appendix B describes the applicant's preventive maintenance activities for the component cooling water heat exchangers, tubesheets, and channel heads. The purpose of these activities is to manage loss of material for parts of the component cooling heat exchanger exposed to raw water. This program is described by the applicant as a 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. This program is credited with managing loss of material for admiralty brass, carbon steel, and stainless steel materials.

The staff’s evaluation of the Heat Exchanger Preventive Maintenance Activities — Component Cooling 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.

[Program Scope] The applicant described the scope of the Heat Exchanger Preventive Maintenance Activities — Component Cooling program to include the McGuire and Catawba component cooling heat exchanger tubes, tubesheets, and channel heads. The staff finds this scope to be appropriate because it includes those components important to the proper functioning of the component cooling system heat exchangers.

[Preventive or Mitigative Actions] The applicant did not identify any actions 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 not to prevent loss of material, but to perform inspections which will identify loss of material in the inspected components and allow actions to be taken prior to loss of component function.

[Parameters Monitored or Inspected] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Component Cooling program inspects the heat exchanger tubes, tubesheetS, and channel head surfaces for loss of material. The staff agrees that inspection of these components will permit actions to be taken prior to loss of component function.

[Detection of Aging Effects] In accordance with the information provided by the applicant under monitoring and trending, the Heat Exchanger Preventive Maintenance Activities — Component Cooling program will detect loss of material due to crevice, galvanic, general, pitting, and microbiologically influenced corrosion, and particle erosion prior to loss of the component pressure boundary function. The staff finds that the inspections are consistent with what is done in the industry, and are capable of detecting aging effects. Therefore, the staff finds that the methods are appropriate.

[Monitoring and Trending] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Component Cooling program performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. Trending is performed in order to predict a heat exchanger replacement or repair schedule. The applicant stated that non-destructive testing (NDT) is performed on approximately 50 percent of the tubes of each heat exchanger, as determined by routine differential pressure testing, based on operating experience and engineering evaluation of test data.

The applicant stated that, with the exception of one Catawba heat exchanger that has no coated components, loss of material of the tubesheets and channel heads of all component cooling heat exchangers is managed by a visual inspection of the protective coatings to assure the integrity of the underlying base metal. This inspection is performed as determined by routine differential pressure testing. The tubesheet and channel heads of the component cooling heat exchangers are coated with a high solids epoxy. The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal. No actions are taken as part of this visual inspection to trend results.

One Catawba component cooling heat exchanger does not currently have any coatings applied to the tubesheets or channel heads. These parts of the heat exchanger are monitored by ultrasonic testing to detect loss of material, and the results are trended. This inspection is performed as required based on trending results.

As a result of the evaluation, the staff finds that the monitoring and trending activities are appropriate for the components being evaluated, both in scope and frequency. The visual inspections are capable of identifying rust blooms, indicating a coating defect and corrosion of the base metal. The ultrasonic testing is capable of detecting metal loss. Therefore, the staff agrees that the monitoring and trending procedures are appropriate.

[Acceptance Criteria] The applicant identified the acceptance criterion for the Heat Exchanger Preventive Maintenance Activities — Component Cooling program as no unacceptable loss of material of the tubes, tubesheets, and channel heads that could result in a loss of the component intended function(s), as determined by engineering evaluation. The staff found that the applicant's acceptance criterion for this program was not adequate to make a reasonable assurance finding, and requested the applicant to specify parameters with quantitative limits or provide specific acceptance criteria (e.g., comparison to design criteria, operating requirements, etc.) that are implemented at Catawba and McGuire to allow for actions to be taken prior to a loss of component function. This issue was characterized as SER open item 3.0.3.9.1.2(d).

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.

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 operating experience associated with the Heat Exchanger Preventive Maintenance Activities — Component Cooling program has demonstrated that the eddy current testing provides adequate information on the extent of wall loss present in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed before the loss of the component intended function. The applicant stated, and the staff agreed, that plant operating experience has demonstrated that measurement and trending of tube wall thickness provides an accurate indication of material condition.

Additionally, the applicant stated that operating experience associated with the Heat Exchanger Preventive Maintenance Activities — Component Cooling program has demonstrated that protective coatings are effective in preventing loss of material on the tubesheets and channel heads. Inspection of the coatings ensures that the protective features of the coatings are maintained intact. Plant operating experience has demonstrated that visual inspection of the coatings provides an accurate indication of material condition. The applicant's experience prior to application of the coatings, and with the tubesheets and channel heads that have not been coated, indicates that loss of material may occur without protective coatings.

The applicant's measurement and trending of tubesheet and channel head wall thickness using ultrasonic techniques provides an accurate indication of material condition. The frequency of monitoring permits the results to be trended in order to determine when corrective action is required.

Based on the review of the applicant’s operating experience, the staff finds that the inspections and monitoring activities have demonstrated that the techniques being used allow for the trending of the loss of material and any required corrective actions to be performed before the loss of component intended function.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.1, and LRA Appendix A-2, Section 18.2.12.1, the applicant provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17.1.2 and is, therefore, acceptable.

The staff has reviewed the information in Section B.3.17.1.2 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(d), 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 — Component Cooling 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).

Based on its review of Tables 3.3-6 and 3.3-7 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the component cooling system, and that there is reasonable assurance that the intended functions of the component cooling system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.5.3 Conclusions*

The staff reviewed the information in Section 2.3.3.5, Tables 3.3-6 and 3.3-7, and Section B.3.17 of LRA Appendix B. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the component cooling system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.6 Condenser Circulating Water System

#### *3.3.6.1 Technical Information in the Application*

The condenser circulating water system provides a suction source of water to the turbine-driven auxiliary feedwater pump for events requiring the activation of the standby shutdown facility. The McGuire and Catawba UFSARs provide more detailed descriptions in Section 10.4.5.

##### 3.3.6.1.1 Aging Effects

Components of the condenser circulating water system are described in Section 2.3.3.6 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-8, pages 3.3-84 through 3.3-86, lists individual components of the system, including pipes, valve bodies, pump casings, and strainers. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from a raw water environment. External surfaces of carbon steel are also subject to the aging effect of loss of material from exposure to sheltered, underground, and yard environments. Carbon steel in an embedded environment is not subject to any aging effect.

3.3.6.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the condenser circulating water system:

- Galvanic Susceptibility Inspection
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection
- Inspection Program for Civil Engineering Structures and Components

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the condenser circulating water system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.6.2 Staff Evaluation*

The applicant described its AMR of the condenser circulating water system for license renewal in two separate sections of its LRA, Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the condenser circulating water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.6.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-4, additional information pertaining to Table 3.3-8. In Table 3.3-8, the applicant indicates that Catawba and McGuire carbon steel condenser circulating water system components are subject to an internal environment of raw water. The staff requested that the applicant confirm that strainers do not perform a component function that may be degraded by the aging effect of fouling in a raw water environment. Similarly, staff requested that the applicant confirm that neither orifices nor strainers, identified in Table 3.3-36, Aging Management Review Results — Nuclear Service Water System (McGuire Nuclear Station), and Table 3.3-37, Aging Management Review Results — Nuclear Service Water System (Catawba Nuclear Station), perform a component function that may be degraded by the aging effect of fouling from exposure to raw water.

In its response dated March 15, 2002, the applicant stated that the strainers in the condenser circulating water system (Table 3.3-8 for both McGuire and Catawba), and in the nuclear service water system (Table 3.3-36 for McGuire and 3.3-37 for Catawba), have a component intended function to maintain pressure boundary integrity. The component intended function of the strainer to maintain pressure boundary integrity will not be degraded by fouling. The orifices in the nuclear service water system (Table 3.3-36 for McGuire and 3.3-37 for Catawba) have two component intended functions (1) to maintain pressure boundary integrity, and (2) to throttle flow. Fouling will not degrade either the pressure boundary function or the throttling function of the orifices. The staff agrees with the applicant that fouling is not an applicable aging effect since heat transfer is not an intended function that meets the scoping criteria of 10 CFR 54.4. The staff finds that the applicant's response clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.6-6, the applicant determined that expansion joints on the discharge of the Catawba condenser cooling water pumps were within the scope of license renewal (see Section 2.3.3.6.2 of this SER). The following AMR results for these components were provided in the applicant’s response:

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effect | Aging Management Programs and Activities |
|---|---|---|---|---|---|
| Expansion Joints | PB | Synthetic Rubber* | Raw Water / Yard | None Identified / None Identified | None Required / None Required |

* A woven polyester and/or nylon fabric coated with chlorobutyl rubber.

The applicant indicated that the external surfaces of these expansion joints are exposed to a “yard” environment, and “no” aging effects are identified. The staff believed that there is potential degradation to the expansion joints if they are exposed to extensive UV rays in a yard environment. If these expansion joints are in a vault, shaded, or covered, then the staff agreed that there are no aging effects for the expansion joints. However, the definition of the yard environment provided in the LRA did not address sunlight exposure. This issue was characterized as SER open item 3.3.6.2.1-1.

During a meeting with the staff on September 18, 2002 (documented in a memorandum dated November 18, 2002), the applicant stated that the expansion joints are located in a pit. Since they are subject to limited UV rays, the applicant stated that degradation from UV is unlikely. However, the staff believes that additional aging effects may be applicable to the expansion joints over time.

In a letter dated October 19, 2002, the staff asked the applicant to provide a basis to justify a service life to the extended operating period (up to 60 years) without aging management or replacement. The staff’s concern was that industry operating experience shows that the main condenser expansion joint constructed with similar materials are typically replaced after 20 to 30 years of service. The staff requested the applicant to provide a basis to justify a service life of the subject pump expansion joint to an extended life of up to 60 years without aging management or replacement.

During a conference call on October 31, 2002, the applicant stated that the main condenser expansion joints are subject to a very harsh environment. They are typically under high (vacuum) pressure, at temperatures higher than 200 to 300 °F, and are exposed to steam and water. The applicant stated that the condenser circulating water system pump expansion joints are subject to a very mild environment with ambient temperatures lower than 100 °F, low pressures, and exposure to raw water internally and outdoor air externally. The applicant also stated that no degradation had been noticed for the subject components during the life of the plant to date.

The applicant provided an official response in a letter dated November 5, 2002. The staff found that the operating environment that was specified for the main condenser seals differed from that which was conveyed by the applicant during the October 31, 2002, conference call. The staff was unable to close the SER open item because of the discrepancy regarding the temperature range to which a main condenser seal (over 100 °F) versus a condenser circulation water system expansion joint (under 100 °F) is typically exposed.

In its November 14, 2002, response, the applicant agreed to add cracking and wear as potential aging effects, and addressed the issue of potential degradation of the synthetic rubber expansion joint in the condenser circulating water system. It proposed to implement a one-time inspection of the expansion joints in order to characterize any cracking and wear of expansion joints exposed to raw water internal and yard external environments. Taking this safety precaution was needed because degradation on synthetic rubber in the expansion joints may cause failure of the pressure boundary in the condenser circulating water system during the period of extended operation. The applicant stated that, based on current operating experience, a one-time inspection of the expansion joints will be adequate for protecting the system.

By letter dated November 18, 2002, the applicant provided the following revised AMR results table for the condenser circulating water system expansion joints:

| Component Type | Component Function | Material | Internal Environment<br>External Environment | Aging Effect | Aging Management Programs and Activities |
|---|---|---|---|---|---|
| Expansion Joints | Pressure Boundary | Synthetic Rubber | Raw Water<br>Yard | Cracking<br>Wear<br>Cracking<br>Wear | Condenser Circulating Water Pump Expansion Joint [Inspection]*<br>Condenser Circulating Water Pump Expansion Joint [Inspection]* |

* The staff interpreted the aging management program to be an inspection.

The aging effects that result from contact of condenser circulating water SSCs to the environments described in Section 2.3.3.6, LRA Table 3.3-8, and in correspondence from the applicant , are consistent with industry experience for these combinations of materials and environments. On the basis of its review, and with the resolution of open item 3.3.6.2.1-1, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.6.2.2 Aging Management Programs

The following aging management programs identified in LRA Section 2.3.3.6 and Table 3.3-8, pages 3.3-84 through 3.3-86, have been evaluated and found to be acceptable for managing the aging effects identified for the condenser circulating water system.

- Galvanic Susceptibility Inspection
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection
- Inspection Program for Civil Engineering Structures and Components

The Galvanic Susceptibility Inspection Program, Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

In its November 14, 2002, response to SER open item 3.3.6.2.1-1, the applicant proposed to implement a one-time inspection of the expansion joints to characterize any cracking and wear of expansion joints exposed to a raw water internal environment and a yard external environment. Taking this safety precaution was needed because degradation of synthetic rubber in the expansion joints may cause failure of the pressure boundary in the condenser circulating water system during the period of extended operation. The applicant stated that, based on current operating experience, a one-time inspection of the expansion joints will be adequate for protecting the system.

<u>Condenser Circulating Water Pump Expansion Joint Inspection</u>

The staff's evaluation of the one-time inspection of the synthetic rubber expansion joint in the condenser circulating water system focuses on how the one-time inspection 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] The applicant defined the scope of the one-time inspection to include the expansion joints in the condenser circulating water system for the Catawba plant. The staff finds that the scope is appropriate for the described purpose because it includes the components that may be affected by the environments to which they are exposed. Also, the component is exposed to a very mild environment with very limited UV exposure, ambient temperature, and very low pressure, and site operating experience has not revealed any evidence of degradation in the current operating term. Therefore, the staff agrees that a one-time inspection is adequate to verify that aging effects will not cause a loss of intended function during the period of extended operating.

[Preventive Actions]  No preventive actions are taken as part of this inspection to prevent aging effects or to mitigate aging degradation.  The staff agrees with the applicant because the purpose of the program is to inspect and determine the condition of the inspected components, rather than prevent their damage.

[Parameters Monitored or Inspected]  The applicant stated that the parameters monitored by the Condenser Circulating Water Expansion Pump Joint Inspection consist of signs of cracking and wear from exposure to the internal and external environments.  The staff finds the parameters monitored to be acceptable because they represent the type of damage expected in the environments to which these components are exposed.

[Detection of Aging Effects]  The applicant stated that the Condenser Circulating Water Pump Expansion Joint Inspection is a one-time visual inspection that will detect the presence and extent of degradation of the internal and external surfaces of the synthetic rubber expansion joints.  The staff finds this inspection acceptable because it would successfully detect relevant aging effects.

[Monitoring and Trending]  The applicant stated that the Condenser Circulating Water Pump Expansion Joint Inspection involves a one-time visual inspection of the internal and external surfaces of the expansion joints in the scope of license renewal for specific signs of cracking, checking, crazing, cuts, tears, blistering, abnormal bulges, scale, flakes, and soft spots. Monitoring and trending of inspection results are not features of this inspection because it will be performed once to verify that the rubber expansion joints are not degrading.  For Catawba, this activity will be implemented following issuance of the renewed operating licenses.  The staff finds that these inspections will provide the applicant the means for determining the condition of the synthetic rubber expansion joints.

[Acceptance Criteria]  The applicant stated that the acceptance criteria for the Condenser Circulating Water Pump Expansion Joint Inspection are based on the results of the evaluation of the inspection findings.  The criteria are qualitatively based on the inspection findings, including cracking, checking, crazing, cuts, tears, blistering, abnormal bulges, scale, flakes, and soft spots.  The staff concurs with the applicant that these results will allow the applicant determine the condition of the synthetic rubber joints.

[Operating Experience]  The Condenser Circulating Water Pump Expansion Joint Inspection is a one-time inspection activity for which there is no operating experience.   However, during the course of other maintenance activities, expansion joints have been inspected and were found to be in good condition.  The staff concludes that there is a good chance that synthetic rubber in the expansion joint will not be degraded during the period of extended operation.  Nonetheless, a one-time inspection is warranted to verify that aging effects will not cause a loss of the pressure boundary function for these components during the period of extended operation.

FSAR Supplement:  In LRA Appendix A-1, Section 18.2.20, the applicant has provided an FSAR supplement for Catawba.  The staff reviewed this information and found it to be consistent with the information provided in the response to open item 3.3.6.2.1-1.  Therefore, the staff concludes that the proposed FSAR supplement for Catawba is acceptable.

The staff reviewed the applicant's response to open item 3.3.6.2.1-1.  On the basis of its review and above evaluation, the staff finds that there is a reasonable assurance that the applicant has demonstrated that the effects of aging associated with the one-time inspection of the expansion joints in the condenser circulating water system 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).

Based on its review of the applicant response to open item 3.3.6.2.1-1, the staff concludes that the above identified AMP will effectively manage the aging effect of the expansion joints in the condenser circulating water system, and there is reasonable assurance that the intended functions of these components will remain consistent with the current licensing basis during the period of extended operation, as required by CFR 54.21(a)(3).

Based on its review of LRA Table 3.3-8, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condenser circulating water system, and that there is reasonable assurance that the intended functions of the condenser circulating water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.6.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.6, LRA Table 3.3-8, and in correspondence from the applicant . On the basis of its review, and with the resolution of open item 3.3.6.2.1-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the condenser circulating water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.7 Containment Ventilation System

#### *3.3.7.1 Technical Information in the Application*

The McGuire upper and lower containment ventilation systems provide cooling to the upper and lower compartments of containment during normal operation and shutdown. The upper and lower containment ventilation systems contain resistance temperature detectors (RTDs) that are required for post-accident monitoring in accordance with the environmental qualification rule. The staff's review of the applicant's environmental qualification program is documented in Section 4.4 of this SER. No mechanical components have an intended function; therefore, no aging management review is required.

#### *3.3.7.2 Staff Evaluation*

The applicant described its AMR of the containment ventilation system for license renewal in LRA Section 2.3.3.7. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging for the containment ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff finds that aging management is not applicable to this section, since there are no mechanical functions provided by any of the components that meet the scoping criteria of 10 CFR 54.4.

*3.3.7.3 Conclusions*

The staff concludes that, since there are no mechanical functions provided by any of the components that meet the scoping criteria of 10 CFR 54.4, an AMR is not required for this system.

**3.3.8 Control Area Ventilation System and Chilled Water System**

*3.3.8.1 Technical Information in the Application*

The control area ventilation system and control area chilled water system combine to form one system to provide the normal and emergency ventilation requirements to the control room and control room area. The McGuire and Catawba UFSARs provide more detailed descriptions in Sections 6.4 and 9.4.1, respectively.

3.3.8.1.1 Aging Effects

Components of the control area ventilation system and control area chilled water system are described in Section 2.3.3.8 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, list individual components of the system, including pipes, valve bodies, pump casings, strainers, tubing, orifices, flow indicators, refrigerant filters, y-strainers, compression tanks, storage tanks, condenser shells, condenser tubes, tubesheets, channel heads, oil separators, oil filters, economizers, evaporator tubes, evaporator tubesheets, chemical feeders, ductwork, filter trains, and evaporator heads.

Carbon steel components are subject to the aging effect of loss of material and cracking of internal surfaces from a treated water environment. Internal surfaces of carbon steel are also subject to loss of material due to exposure to raw water. External surfaces of carbon steel are also subject to an aging effect of loss of material from exposure to sheltered environments. Exposure of internal or external carbon steel surfaces to gas or oil environments has no aging effects.

Internal surfaces of stainless steel components are subject to the aging effect of loss of material and cracking due to exposure to a treated water environment. Exposure of internal or external surfaces of stainless steel components to sheltered, gas, or oil environments has no aging effects. Cast iron components exposed to an internal environment of treated water are subject to the aging effect of loss of material, while external surfaces exposed to sheltered environments are also subject to the aging effect of loss of material. Exposure of cast iron to a gas or oil environment has no aging effect. Internal surfaces of copper-nickel components are subject to the aging effects of fouling and loss of material from exposure to raw water environment. Internal surfaces of copper-nickel components also experience the aging effect of loss of material due to exposure to a treated water environment. External surfaces of copper-nickel components exposed to a gas environment experience no aging effects.

Components made of copper exposed to a treated water environment experience the aging effects fouling and loss of material. Exposure of copper components to a gas environment results in no aging effect. Components made of admiralty brass exposed to a treated water environment experience the aging effects of cracking and loss of material. Copper components exposed to an oil environment do not experience any aging effects. There are no aging effects to the internal surfaces of galvanized steel and brass components exposed to a ventilation environment. External surfaces of galvanized steel and brass components exposed to yard and sheltered environments also do not experience any aging effects.

3.3.8.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the control area ventilation and chilled water systems:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water
- Service Water Piping Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the control area ventilation and chilled water systems will be adequately managed by these aging management programs during the period of extended operation.

*3.3.8.2 Staff Evaluation*

The applicant described its AMR of control area ventilation and chilled water systems for license renewal in four separate sections of its LRA, Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the control area ventilation and chilled water systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.8.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAIs 3.3-1 and 3.3-3, additional information from the applicant. The staff's evaluation of the applicant's response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER, and is characterized as resolved.

In RAI 3.3-3, the staff requested the applicant to address information provided in LRA Tables 3.3-9 (pages 3.3-91 to 3.3-93) and 3.3-10 (pages 3.3-103 to 3.3-104). These tables indicate that certain Catawba and McGuire control room area chiller components (oil cooler tubes, tubesheets, and shells) are subject to an internal/external environment of treated water/oil. In RAI 3.3-3, the staff requested the applicant to identify where in the LRA the aging effect of loss of material for these components in oil systems subject to water contamination was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant’s treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function. The applicant identified cracking and shrinkage of structural sealants in the interface between a structural wall, floor, or ceiling and a nonstructural component (such as a duct, piping, electrical cables, doors, and nonstructural walls) resulting from exposure to ambient conditions as potential aging effects.

The aging effects that result from contact of the control area ventilation SSCs to the environments described in LRA Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, and in correspondence from the applicant, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.8.2.2 Aging Management Programs

LRA Section 2.3.3.8 and Tables 3.3-9, 3.3.10, and 3.3.11, pages 3.3-87 through 3.3-113, state that the following aging management programs are credited for managing the aging effects in the control area ventilation and chilled water systems:

- Fluid Leak Management Program
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water
- Service Water Piping Corrosion Program

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The Fluid Leak Management Program, Chemistry Control Program, Service Water Piping Corrosion Program, Inspection Program for Civil Engineering Structures and Components, and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program follows.

Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water Program

The applicant described its Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water in Section B.3.17.4 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

The applicant provided a discussion of the preventive maintenance activities of the control area chilled water heat exchangers in Section B.3.17.4 of LRA Appendix B. The applicant stated that the purpose of this program is to manage fouling and loss of material of the parts of the control room area chillers exposed to raw water. This is defined by the applicant as a 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 functions, and periodically cleans the chiller tubes to manage fouling. The applicant credited the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program with managing loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials.

The staff's evaluation of the preventive maintenance testing activities of the control area chilled water heat exchangers 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.

[Program Scope] The applicant defined the scope of the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program to include the McGuire and Catawba control room chiller condenser tubes and channel heads. The staff finds the scope to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[Preventive or Mitigative Actions] The applicant stated that there are no actions taken as part of this program to prevent aging effects or to mitigate aging degradation. The staff agreed that this program is designed to monitor and inspect the components and, therefore, preventive or mitigative actions are not required.

[Parameters Monitored or Inspected] The applicant stated that the program inspects the chiller tubes and channel heads to provide an indication of loss of material. The staff finds the inspection parameters to be acceptable because they will permit the applicant to receive early warning of potential loss of wall material in the tubes.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under the Monitoring and Trending section, the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program will detect loss of material due to crevice, galvanic, general, pitting, microbiologically influenced corrosion, and particle erosion prior to loss of the component's pressure boundary function. The applicant stated that the program will also manage fouling prior to the loss of the heat transfer function. The staff agreed that the program is capable of detecting loss of material to allow for corrective actions to be taken prior to the loss of function and, therefore, finds this to be acceptable.

[Monitoring and Trending] The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material. The applicant performs NDT on approximately 50 percent of the control room chiller condensers at least every 5 years. The applicant then performs an analysis following each NDT to determine the need for further testing, replacement, or repair.

The applicant stated that fouling of the internal portions of the chiller tubes exposed to raw water is managed by routine cleaning. At least annually, the tubes are rodded out and cleaned. No action is taken as part of this activity to trend inspection results. The applicant stated that loss of material of the channel heads is managed by an annual visual inspection of the protective coatings to assure the integrity of the underlying base metal. The channel heads of the control room area chillers are coated with a high solids epoxy. The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal. No action is taken as part of this activity to trend inspection results.

The staff finds that the monitoring and inspection activities are acceptable because they are capable of identifying loss of material to allow for corrective action to be taken prior to loss of component function. The applicant does not trend the results of the inspections, and the staff did not identify a need for such trending because actions are taken based on inspection findings.

[Acceptance Criteria] The applicant stated that the acceptance criteria for the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program is no unacceptable loss of material of the tubes and channel heads that could result in a loss of the component's 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, and this issue was characterized as SER open item 3.0.3.9.1.2(e).

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.

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 operating experience associated with the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program has demonstrated that the eddy current testing provides adequate information on the extent of wall loss present in the chiller tubes to predict when corrective action is required.  Corrective action, in the form of tube plugging, for example, is performed before the loss of component intended function.

The applicant stated that periodic tube cleaning has proven to be an effective method of managing fouling of the tubes that could lead to loss of heat transfer. The applicant stated that the control area chiller operates during normal plant operation. The applicant's routine surveillance of the chiller's operating parameters indicated that periodic cleaning is effective in managing fouling of the chiller tubes. The applicant stated that experience prior to the application of the coatings of the carbon steel channel heads indicated that loss of material was occurring. Due to the inspection results, the applicant recently coated the channel heads. Future inspection of the coatings should allow the applicant to ensure that the protective features of the coatings are maintained intact.

The applicant's operating experience has demonstrated that Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program is an effective program for managing the effects of aging. The program with its proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls, accurately predicts aging effects due to corrosion and erosion.

The staff finds that the applicant is properly making use of the operating experience with the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program, and has demonstrated the ability of the program to properly manage aging effects of the chiller tubes.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.4, and LRA Appendix A-2, Section 18.2.12.4, the applicant provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17.4 and is, therefore, acceptable.

During its review of information in Section 2.3.3.8; Tables 3.3-9, 3.3-10, and 3.3-11, pages 3.3-87 through 3.3-113; and Section B.3.17.4 of LRA Appendix B, the staff identified the need for additional information pertaining to this AMP. In Tables 3.3-9 and 3.3-10 of the LRA, the applicant indicates that the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program is credited for managing the aging effects of fouling and loss of material for copper-nickel alloy materials. The Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program, as defined in Appendix B of the LRA, manages the loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials, but the description in Appendix B does not include the copper-nickel material in the scope of the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program. By letter dated January 23, 2002, the staff requested, in RAI 3.3.9-1, that the applicant explain how the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program manages the loss of material or fouling for copper-nickel alloy materials, or provide an AMP for managing these aging effects for this material.

In its response dated March 15, 2002, the applicant stated that the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program, as described in Section B.3.17.4 of LRA Appendix B, is credited for managing fouling and loss of material for the copper-nickel alloy tubes. The copper-nickel alloy material was inadvertently omitted from the introductory paragraph in the program description in Appendix B of the application. The program description does describe how fouling and loss of material of the copper-nickel alloy heat exchanger tubes are managed. The applicant further stated that Section 18.2.13.4 of the McGuire FSAR supplement, and Section 18.2.12.4 of the Catawba FSAR supplement, will be revised to indicate that the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program is credited for managing loss of material or fouling for admiralty brass, carbon steel, copper-nickel alloy, and stainless steel materials. Since the applicant's AMP manages fouling and loss of material of copper-nickel alloy components, and the applicant has added copper-nickel alloy components to the AMP description in the FSAR supplements, the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.4 of LRA Appendix B. On the basis of this review and the above evaluation, and with the resolution of SER open item 3.0.3.9.1.2(e), the staff finds that the applicant has demonstrated that the effects of aging associated with the Heat Exchanger Preventive Maintenance Activities — Control Area Chilled Water program will be adequately managed, so 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).

Based on its review of Tables 3.3-9, 3.3-10, and 3.3-11, and LRA Appendix B, as well as correspondence from the applicant, the staff concludes that the above identified AMPs will effectively manage the aging effects of the control area ventilation and chilled water systems, and that there is reasonable assurance that the intended functions of these systems will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.8.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.8, Tables 3.3-9, 3.3-10 and 3.3-11, and Section B.3.17 of LRA Appendix B. The staff also reviewed information provided in correspondence from the applicant. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the control area ventilation and chilled water systems will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.9 Conventional Wastewater Treatment System

#### *3.3.9.1 Technical Information in the Application*

The McGuire conventional wastewater treatment system maintains water level in the standby shutdown facility (SSF) sump to prevent flooding of the SSF equipment. The McGuire UFSAR provides a more detailed description in Section 9.2.8.

##### 3.3.9.1.1 Aging Effects

Components of the conventional wastewater treatment system are described in Section 2.3.3.9 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-12, pages 3.3-114 through 3.3-115, lists individual components of the system, including pipe, pump casings, and valve bodies. Internal surfaces of carbon steel and cast iron components exposed to a raw water environment are subject to the aging effect of loss of material. External surfaces of carbon steel and cast iron components exposed to sheltered environments also are subject to the aging effect of loss of material. Embedded carbon steel components experience no aging effects.

3.3.9.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the conventional wastewater treatment system:

- Galvanic Susceptibility Inspection
- Sump Pump System Inspection
- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the conventional wastewater treatment system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.9.2 Staff Evaluation*

The applicant described its AMR of the conventional wastewater treatment system for license renewal in two separate sections of its LRA, Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the conventional wastewater treatment system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.9.2.1 Aging Effects

The aging effects that result from contact of the conventional wastewater treatment SSCs to the environments described in LRA Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.9.2.2 Aging Management Programs

LRA Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115, state that the following aging management programs are credited for managing the aging effects in the conventional wastewater treatment system:

- Galvanic Susceptibility Inspection
- Sump Pump System Inspection
- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection

The Galvanic Susceptibility Inspection Program, Sump Pump System Inspection Program, Inspection Program for Civil Engineering Structures and Components, and Selective Leaching

Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-12, the staff concludes that the above identified AMPs will effectively manage the aging effects of the conventional wastewater treatment system, and that there is reasonable assurance that the intended functions of the conventional wastewater treatment system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.9.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.9 and Table 3.3-12, pages 3.3-114 through 3.3-115. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the conventional wastewater treatment system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.10 Diesel Building Ventilation System

*3.3.10.1 Technical Information in the Application*

The diesel building ventilation system maintains temperature control for each diesel building when its associated diesel generator is running. The McGuire and Catawba UFSARs provide more detailed descriptions in Sections 9.4.6 and 9.4.4, respectively.

3.3.10.1.1 Aging Effects

Components of the diesel building ventilation system are described in Section 2.3.3.10 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-13, pages 3.3-116 through 3.3-117, lists individual components of the system, including pipe, tubing, ductwork, and valve bodies. External surfaces of carbon steel components are subject to the aging effect of loss of material from exposure to sheltered environments. Internal and external surfaces of stainless steel, brass, galvanized steel and copper components exposed to ventilation and sheltered environments are not subject to any aging effects because there is no potential for boric acid contamination of components in this building.

3.3.10.1.2 Aging Management Programs

The Inspection Program for Civil Engineering Structures and Components is utilized to manage aging effects for the diesel building ventilation system. A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel building ventilation system will be adequately managed by the aging management program during the period of extended operation.

*3.3.10.2 Staff Evaluation*

The applicant described its AMR of the diesel building ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.10 and Tables 3.3-13, pages 3.3-116 through 3.3-117. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging on the diesel building ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.10.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.10 and Table 3.3-13, pages 3.3-116 through 3.3-117. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff asked, in RAI 3.3-1, the applicant to indicate why AMR results tables for numerous ventilation systems in LRA Section 3.3 do not list elastomer components associated with duct seals, flexible collars between ducts and fans, rubber boots, etc. The staff's evaluation of the applicant's April 15, 2002, response to RAI 3.3-1, pertaining to aging of ventilation system flexible connectors, is documented in Section 3.3.39.3 of this SER, and is characterized as resolved.

The aging effects that result from contact of the diesel building ventilation SSCs to the environments described in LRA Section 2.3.3.10 and Table 3.3-13, pages 3.3-116 through 3.3-117, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.10.2.2 Aging Management Programs

LRA Section 2.3.3.10 and Tables 3.3-13, pages 3.3-116 through 3.3-117, state that the Inspection Program for Civil Engineering Structures and Components is credited for managing the aging effects in the diesel building ventilation system. The Inspection Program for Civil Engineering Structures and Components 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-13, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel building ventilation system, and that there is reasonable assurance that the intended functions of the diesel building ventilation system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.10.3 Conclusions*

The staff reviewed the information in Section 2.3.3.10 and Table 3.3-13 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel building ventilation system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.11 Diesel Generator Air Intake and Exhaust System

#### *3.3.11.1 Technical Information in the Application*

The diesel generator air intake and exhaust system is essentially the same, and performs the same function, for McGuire and Catawba. The diesel generator air intake and exhaust system supplies sufficient air to the diesel generator engines for fuel consumption, and removes exhaust from the diesel generator engines to the atmosphere outside the building. McGuire UFSAR Section 9.5.11, "Diesel Generator Air Intake and Exhaust System," provides additional information concerning the McGuire diesel generator air intake and exhaust system. Catawba UFSAR Section 9.5.8, "Diesel Generator Air Intake and Exhaust System," provides additional information concerning the Catawba diesel generator air intake and exhaust system.

##### 3.3.11.1.1 Aging Effects

Components of the diesel generator air intake and exhaust system are described in Section 2.3.3.11 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-14, pages 3.3-118 through 3.3-120, lists individual components of the system, including exhaust silencers, filters, flexible connectors, expansion joints, hoses, tubing, pipes, and valve bodies. Stainless steel components are identified as being subject to an internal ventilation environment and an external sheltered environment with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces from sheltered and yard environments. Carbon steel components are identified as being subject to the internal environment of ventilation with no aging effects identified. Rubber and composite rubber components exposed to internal ventilation environment and an external sheltered environment have no identified aging effects.

##### 3.3.11.1.2 Aging Management Programs

The Inspection Program for Civil Engineering Structures and Components is utilized to manage aging effects for the diesel generator air intake and exhaust system. A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator air intake and exhaust system will be adequately managed by the aging management program during the period of extended operation.

#### *3.3.11.2 Staff Evaluation*

The applicant described its AMR of the diesel generator air intake and exhaust system for license renewal in two separate sections of its LRA, Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator air intake and exhaust system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.11.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120. During its review, the staff determined that additional information was needed to complete its review and, on January 23, 2002, issued RAIs 3.3-5, 3.3.14-1, and 3.3.14-2. The staff's evaluation of the applicant's responses is provided below.

In the LRA, the applicant stated that all of the components in Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," are subject to an interior environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1609-5.0, CN-2609-5.0, MCFD-1609-5.00 and MCFD-2609-5.00, "Flow Diagrams for Diesel Engine Air Intake and Exhaust System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. Similarly, Table 3.3-44, "Aging Management Review Results — Standby Shutdown Diesel Generator, Exhaust Sub-System," components are subject to an internal environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560.20, MCFD-1560-1.00, MCFD-1560.20, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. In RAI 3.3-5, the staff requested that the applicant provide justification for classifying the internal environment for these components as "ventilation."

In its response to RAI 3.3-5, dated March 15, 2002, the applicant stated that the staff is correct that these components are subject to a sheltered internal environment. Duke's aging management review conservatively evaluated environments, such as tanks and piping, that are open to atmosphere as a ventilation environment. Although the tanks and piping are open to sheltered environments, they would not experience significant air exchange, and thus higher humidity and condensation could be present. The ventilation environment aging effect details account for the potential condensation, whereas the sheltered environment aging effect details do not. Loss of material and cracking due to alternate wetting and drying that concentrates contaminants are two aging effects considered plausible in a ventilation environment, but are not considered in sheltered environments. Loss of material due to selective leaching is another aging effect considered plausible in a ventilation environment, but is not considered in sheltered environments. Therefore, for conservatism, Duke chose to evaluate these component configurations using the ventilation environment aging management review details. The designation in the LRA table reflects this decision.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff requested additional justification for the applicant's statement in Table 3.3-14 that carbon steel external components are subject to a sheltered environment, while the internal environment is ventilation. The sheltered environment is subject to the aging effect of loss of material and is managed by the Inspection Program for Civil Engineering Structures and Components. This appeared to the staff to conflict with Duke's RAI response, which states that loss of material in sheltered environments is not considered an aging effect. The staff requested that the applicant clarify or justify how an "uncontrolled" sheltered environment is less conservative than a "controlled" ventilation environment and causes no aging effects, or revise the aging effects and AMPs listed in Table 3.3-14 to be consistent with other sheltered environments listed in the tables. The staff further noted that its fundamental concern was that, for the diesel engine exhaust systems (which include no equipment (coolers or dryers) for controlling air quality), the internal environments are “sheltered,” not “ventilation,” and that the aging effects associated with the sheltered environment must be addressed for these internal surfaces.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant replied as follows—

> For Duke, a sheltered environment is an external environment for components inside a structure that may or may not be maintained by a ventilation system but are protected from the natural elements. Components in a sheltered environment could be wet from condensation or leakage that could promote aggressive corrosion, that left unmanaged, could result in a loss of the component intended function(s) during the period of extended operation. As such, the Inspection Program for Civil Engineering Structures and Components is credited to manage the aging effects on the external surfaces of components located in a sheltered environment.
>
> For components with an internal air environment open to the sheltered environment or yard environment (as is the case with the diesel exhaust), Duke classified the environment as a ventilation environment. Duke conservatively chose the ventilation environment because more aging mechanisms leading to aging effects are plausible and must be considered than in a sheltered environment. In our initial response to RAI 3.3-5, Duke tried to show that aging effects from some mechanisms are not plausible in a sheltered environment but could occur in a ventilation environment. Duke was providing examples to support our conservative position which we believe does not say that loss of material in a sheltered environment is not an aging effect.
>
> Duke evaluated the internal environment of the exhaust systems as a ventilation environment. The diesels operate periodically for short periods of time for testing but are primarily in standby. The internal environment is characterized as a warm, dry environment free from leaks and condensation. This environment does not preclude loss of material but does not promote the aggressive corrosion that left unmanaged would result in a loss of the component intended function(s) of the exhaust system components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this information from the applicant in official correspondence. The applicant confirmed that the internal environment is warm, dry, and free from leaks and condensation. Since this environment does not promote the aggressive corrosion that would result in a loss of the component intended function(s) of the exhaust system components, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.14-1, additional information pertaining to Table 3.3-14 of the LRA, “Aging Management Review for Diesel Generator Air Intake and Exhaust System.” This table does not list an internal environment of hot diesel engine exhaust gasses containing moisture and particulates. By letter dated January 23, 2002, the staff requested the applicant to identify where in the LRA the AMR results are for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting and crevice corrosion, or to provide a justification for excluding this environment and aging effects from Table 3.3-14 and an AMR.

In its response dated March 15, 2002, the applicant stated that Table 3.3-14 of the LRA presents the results of the aging management review for the diesel generator intake and exhaust system components. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, Table 3.3-14 listed ventilation as the internal environment and did not include hot gasses as an internal environment. The staff finds that the applicant's response provides a reasonable explanation of why the environment is ventilation rather than exhaust. Since the standby diesel generators only test run periodically, the staff agrees that the subject exhaust components will not be exposed to the hot gasses containing moisture and particulates.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.14-2, additional information pertaining to information provided in Table 3.5-2 of the LRA, "Aging Management Review Results for Other Structures." This table indicates that rubber materials in sheltered environments are subject to the aging effects of cracking and change in material properties. The staff requested that the applicant explain why the rubber and composite rubber materials of Table 3.3-14, that are also in sheltered environments, are not subject to the aging effects of cracking and change in material properties.

In its response dated March 15, 2002, the applicant stated that elastomers could crack due to exposure to ultraviolet radiation, ozone, elevated temperature, or irradiation. Elastomers could experience a change in material properties due to exposure to elevated temperatures or irradiation. Damaging levels of radiation, temperature, and ozone are not present throughout the entire sheltered environment. As a result, elastomer location must be considered to identify the aging effects requiring management. The elastomers in Table 3.3-14 of the LRA are located in the diesel room. Radiation, temperature, and ozone are below the levels to be a concern in this location. Therefore, no aging effects requiring management were identified for these elastomers. Since the applicant indicated that these elastomers are located in an area where radiation and temperature are not significant enough to cause degradation, the staff finds the response acceptable.

The staff finds that the applicant's responses to RAIs 3.3.14-1 and 3.3.14-2 clarify and satisfactorily resolve these items. The aging effects that result from contact of diesel generator air intake and exhaust SSCs to the environments described in LRA Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.3.11.2.2 Aging Management Programs

LRA Section 2.3.3.11 and Table 3.3-14, pages 3.3-118 through 3.3-120, state that the Inspection Program for Civil Engineering Structures and Components is credited for managing the aging effects in the diesel generator air intake and exhaust system. The Inspection Program for Civil Engineering Structures and Components 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-14, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel generator air intake and exhaust system, and that there is reasonable assurance that the intended functions of the diesel generator air intake and exhaust system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.11.3 Conclusions*

The staff reviewed the information in Section 2.3.3.11 and Table 3.3-14 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator air intake and exhaust system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.12 Diesel Generator Cooling Water System

*3.3.12.1 Technical Information in the Application*

The diesel generator cooling water system is essentially the same, and performs the same function, for McGuire and Catawba. The diesel generator cooling water system maintains the temperature of each emergency diesel generator engine, and support systems, within a required operating range. McGuire UFSAR Section 9.5.5, "Diesel Generator Cooling Water System," provides additional information concerning the McGuire diesel generator cooling water system. Catawba UFSAR Section 9.5.5, "Diesel Generator Engine Cooling Water," provides additional information concerning the Catawba diesel generator engine cooling water system.

3.3.12.1.1 Aging Effects

Components of the diesel generator cooling water system are described in Section 2.3.3.12 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, list individual components of the system, including the annubars, tanks, heat exchanger, intercoolers, pumps, heaters, flow orifices, piping, tubing, lube oil coolers, stand pipes, and valve bodies. Stainless steel components are identified as being subject to cracking and loss of material from exposure to the internal environment of treated water. Exposure of stainless steel to sheltered environment has no aging effects. Carbon steel components are subject to the aging effect of loss of material from internal surfaces from treated water and raw water environments. Internal surfaces of carbon steel components are also subject to cracking from exposure to treated water environments. Carbon steel is also subject to an aging effect of loss of material to external surfaces from exposure to sheltered environments. Exposure of internal surfaces of carbon steel components to a ventilation environment has no aging effect, except for the diesel generator cooling water surge tanks at McGuire and the jacket water standpipes at Catawba.

Copper components are exposed to an internal and external environment of ventilation with no aging effects identified. Copper components exposed to an internal and external environment of raw water and treated water are subject to the aging effects of fouling and loss of material. Cast iron components exposed to treated water and sheltered environments are subject to loss of material from internal and external surfaces. Brass components exposed to internal and external environments of raw water and treated water are subject to the aging effects of fouling and loss of material. Internal surfaces of aluminum components exposed to treated water are subject to cracking and loss of material. Aluminum and brass exposed to oil or sheltered environments demonstrate no aging effects.

3.3.12.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the diesel generator cooling water system:

- Galvanic Susceptibility Program
- Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Performance Test Activities — Diesel Engine Cooling Water Exchanger
- Service Water Piping Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator cooling water system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.12.2 Staff Evaluation*

The applicant described its AMR of the diesel generator cooling water system for license renewal in two separate sections of its LRA, Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator cooling water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.12.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information pertaining to LRA Tables 3.3-16, 3.3-20, and 3.3-21. According to Table 3.3-16, the Catawba diesel generator governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. Similarly, LRA Tables 3.3-20 and 3.3-21 indicate that the diesel generator engine lube oil coolers (tubes, tubesheets, and/or shells) are listed as subject to an internal/external environment of treated water/oil. The staff requested the applicant to identify where in the LRA the aging effect of loss of material for these components in oil systems subject to water contamination was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the diesel generator cooling water SSCs to the environments described in LRA Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.12.2.2 Aging Management Programs

LRA Section 2.3.3.12 and Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130, state that the following aging management programs are credited for managing the aging effects in the diesel generator cooling water system.

- Galvanic Susceptibility Program
- Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water
- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components
- Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers
- Service Water Piping Corrosion Program

The Galvanic Susceptibility Inspection Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Service Water Piping Corrosion Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers program and Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water program follows.

<u>Performance Testing Activities — Diesel Generator Engine Cooling Water Heat Exchangers</u>

The applicant described its Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers in Section B.3.17.3.1 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

The applicant stated that the purpose of the Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers is to manage fouling of copper and brass heat exchanger tubes that are exposed to raw water. This is considered by the applicant to be a performance monitoring program that monitors specific component parameters to detect the presence of fouling, which can affect the heat transfer function of the component.

The staff's evaluation of the Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers 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.

[Program Scope] The scope of the Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers includes the tubes of the following components:

- diesel generator engine cooling water heat exchangers (McGuire only)
- diesel generator engine jacket water coolers (Catawba only)

The applicant noted that these components serve the same function at both plants, but have different names because of the different diesel suppliers.

The staff finds the scope of the program to be acceptable because it covers 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, not to prevent such loss.

[Parameters Monitored or Inspected] The applicant stated that at McGuire, the Performance Test Activities — Diesel Generator Engine Cooling Water Heat Exchangers involve monitoring of flow capacity by performance of a differential pressure test to provide an indication of fouling. At Catawba, the performance testing activities involve monitoring of the heat transfer capability by performance of a heat capacity test to provide an indication of fouling. The staff finds the parameters monitored to be acceptable because they are typical of industry practice for determining fouling in heat exchanger tubes. The different methods used at the two plants are both acceptable methods of testing.

[Detection of Aging Effects] The applicant stated that in accordance with the information provided under Monitoring and Trending, the performance testing activities will detect fouling prior to loss of the component intended function(s). The staff finds the applicant's approach acceptable because it is based on standard industry-approved methods.

[Monitoring and Trending] The applicant stated that, due to different system design features at McGuire and Catawba, different parameters are monitored to manage fouling of the heat exchanger tubes. At McGuire, the performance testing activities involve measurement of the differential pressure across the raw water side of the heat exchangers every 6 months. Differential pressure provides a direct indication of fouling of the heat exchanger tubes. At Catawba, a heat capacity test computes a tube side fouling factor using tube and shell side inlet and outlet temperatures and flow rates every 6 months. Heat capacity provides a direct indication of fouling of the heat exchanger tubes. The staff finds that the monitoring and trending methods used, although different at the two plants, rely on standard engineering methods which are equally capable of detecting fouling in the heat exchanger tubes. Because the monitoring methods will allow the applicant to detect and correct fouling before it results in loss of cooling function, the staff finds the monitoring activities to be acceptable.

[Acceptance Criteria] The applicant stated that at McGuire, the acceptance criterion 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. At Catawba, the applicant stated that the acceptance criteria for the performance testing activities are established by engineering calculation, and the comparison of the test results to the acceptance criteria ensures fouling does not prevent the heat exchangers from performing their design basis function. The staff finds the acceptance criteria for both plants to be acceptable because the testing methods 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 operating experience associated with the performance testing activities has demonstrated that the fouling factor and the tube side differential pressure provide adequate indications to predict when corrective action is required for heat transfer surface fouling. Corrective action, in the form of tube cleaning, for example, is performed before the heat transfer function of the heat exchanger tubes is degraded below its required capacity. The applicant stated that with relatively low in-service duration and good valve isolation, the diesel generator engine cooling water heat exchangers usually do not accumulate large amounts of fouling materials on internal tubing surfaces.

The applicant’s measurement and trending of the heat exchanger tubes using NDT provides an accurate indication of material condition. The frequency of monitoring permits the results to be trended in order to determine when corrective action is required. Based on the review of the applicant’s operating experience, the staff finds that the inspections and monitoring activities have demonstrated that the techniques being used allow for the trending of the loss of material, and any required corrective actions to be performed before the loss of component intended function.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.3, and LRA Appendix A-2, Section 18.2.12.3, the applicant has provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in Appendix B, Section B.3.17.3.1 and is, therefore, acceptable.

In conclusion, the staff has reviewed the information in Section B.3.17.3.1 of the LRA. 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 Performance Testing Activities — Diesel Generator Engine Cooling Water Heat Exchangers 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).

Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water

The applicant described its Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water in Section B.3.17.3.2 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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).

The applicant stated that the purpose of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water is to manage the loss of material for the parts of the diesel generator engine cooling water heat exchangers exposed to raw water. The Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water is a 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. The applicant credited the program with managing the subject aging effects for brass and copper heat exchanger tubes.

The staff's evaluation of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water 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.

[Program Scope] The applicant defined the scope of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water as the tubes of the following components:

- diesel generator engine cooling water heat exchangers (Mcguire only)
- diesel generator engine jacket water coolers (Catawba only)

The applicant noted that these components serve the same function at both plants, but have different names because of the different diesel suppliers.

The staff noted that the applicant relies on other aging management programs, such as the Chemistry Control Program, to manage the aging effects of the heat exchanger shell, channel head, and tubesheets. The staff finds the scope to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[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, not to prevent such loss.

[Parameters Monitored or Inspected]  The Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water program consists of the inspection of the heat exchanger tubes that will provide an indication of loss of material.  The staff finds the applicant's approach acceptable because the inspections will identify areas affected by corrosion or erosion, and provide an opportunity to take corrective actions prior to loss of pressure boundary integrity.

[Detection of Aging Effects]  The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water inspections will detect loss of material due to crevice, general, pitting, microbiologically influenced corrosion, and loss of material due to particle erosion prior to loss of the component intended function.  The staff finds this acceptable because the inspection methods used have been demonstrated to be capable of identifying the corrosion and erosion effects that are relied on as indications of tube wall thinning.

[Monitoring and Trending]  The applicant stated that the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water program performs eddy current testing on the heat exchanger tubes to measure wall thickness in order to detect areas with loss of material.  Trending is performed in order to predict a heat exchanger replacement or repair schedule.  The applicant stated that NDT (eddy current) is performed on approximately 50 percent of the tubes of each heat exchanger, as determined by routine differential pressure testing, based on operating experience and engineering evaluation of the test data.  The staff finds this acceptable because eddy current testing is a standard method used in the industry for this type of inspection.  The staff agrees that by trending the test data and use of operating experience, the applicant will be able to schedule replacement or repair prior to loss of component function.

[Acceptance Criteria]  The applicant stated that the acceptance criterion for the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water program is no unacceptable loss of material of the tubes that could result in a loss of the component intended function, as determined by engineering evaluation.  The staff did not consider this an adequate acceptance criterion for the heat exchanger preventive maintenance activities AMP.  In addressing the acceptance criteria, the staff requested the applicant to specify parameters with quantitative limits, and this issue was characterized as SER open item 3.0.3.9.1.2(f).

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.

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 operating experience associated with the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Cooling Water program has demonstrated that the eddy current testing provides adequate information in regards to the presence of wall loss in the heat exchanger tubes to predict when corrective action is required. Corrective action in the form of tube plugging, for example, is performed before the loss of the component's intended function.

Due to operating experience at Catawba, the applicant stated that the frequency of eddy current testing had been increased at both sites. During 1992 and 1993, the Catawba 2 diesel generator engine cooling water heat exchangers experienced circumferential cracking of the tubes. Complete tube severance occurred on several tubes. The investigation by the applicant revealed that the Catawba 2 heat exchangers were set up on a weekly nuclear service water system flush schedule (whereas Catawba 1 heat exchangers were not). Circumferential cracks were determined to be linked to the thermal shock received during the nuclear service water flushes. The applicant discontinued the flushes and a special eddy current test probe was employed to determine the extent of circumferential cracking defects. Repairs were in the form of plugging and re-tubing.

The applicant's operating experience has demonstrated that the diesel generator engine cooling water heat exchanger activities program is an effective program for managing the effects of aging. The program with its proven monitoring techniques, acceptance criteria, and corrective actions accurately predicts aging effects due to erosion and corrosion. Therefore, the staff finds that the applicant is effectively applying the operating experience at their sites to improve the preventive maintenance activities related to the diesel generator engine cooling water system.

FSAR Supplement: In LRA Appendix A-1, Section 18.2.13.3, and LRA Appendix A-2, Section 18.2.12.3, the applicant provided proposed FSAR supplements for McGuire and Catawba, respectively. The staff reviewed this information and found it to be in agreement with the information in Section 3.17.3.2 of LRA Appendix B and is, therefore, acceptable.

During its review of the information in Section 2.3.3.12; Tables 3.3-15 and 3.3-16, pages 3.3-121 through 3.3-130; and Section B.3.17.3.2 of the LRA, the staff identified the need for additional information pertaining to this AMP. By letter dated January 23, 2002, the staff requested, in RAI 3.3.15-1, additional information pertaining to Table 3.3-15, "Aging Management Review Results for Diesel Generator Cooling Water System (McGuire Nuclear Station)." This table indicates that the aging effect of loss of material in a raw water environment to the diesel generator cooling water heat exchangers is managed by the Galvanic Susceptibility Inspection program. The scope of this program, as defined in Appendix B, Section B.3.16, of the LRA does not include the diesel generator cooling water heat exchangers. The staff requested confirmation that the Galvanic Susceptibility Inspection program manages the aging effects to the diesel generator cooling water heat exchangers.

In its response dated March 15, 2002, the applicant stated that the diesel generator cooling water heat exchangers reject heat from the diesel generator cooling water system to the nuclear service water system. The channel heads and tubesheets are constructed of carbon steel that is electrolytically coupled to stainless steel and copper, respectively, in the presence of raw water supplied by the nuclear service water system. The scope of the Galvanic Susceptibility Inspection, as described in Appendix B of the LRA, includes the galvanic couples of the nuclear service water system, which would include the galvanic couples in the portion of the diesel generator cooling water heat exchangers exposed to raw water in the nuclear service water system. Since the scope of the Galvanic Susceptibility Inspection includes the galvanic couples in a portion of the diesel generator cooling water heat exchangers, the aging effect will be managed by the program. The staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.3.2, Appendix B of the LRA. On the basis of this review and the above evaluation, and with the resolution of open item

3.0.3.9.1.2(f), 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 — Diesel Generator Engine Cooling Water 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).

Based on its review of Tables 3.3-15 and 3.3-16 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator cooling water system, and that there is reasonable assurance that the intended functions of the diesel generator air intake and exhaust system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.12.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.12 and Tables 3.3-15 and 3.3-16. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator cooling water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.13 Diesel Generator Crankcase Vacuum System

*3.3.13.1 Technical Information in the Application*

The diesel generator crankcase vacuum system is essentially the same, and performs the same function, for McGuire and Catawba. The diesel generator crankcase vacuum system purges the diesel engine crankcase to reduce the concentration of combustible gasses. McGuire UFSAR Section 9.5.9, “Diesel Generator Crankcase Vacuum System,” provides additional information concerning the McGuire diesel generator crankcase vacuum system.

3.3.13.1.1 Aging Effects

Components of the diesel generator crankcase vacuum system are described in Section 2.3.3.13 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-17, pages 3.3-131 through 3.3-133, lists individual components of the system, including the blowers, oil separators, orifices, piping, tubing, and valve bodies. Stainless steel components exposed to sheltered and ventilation environments demonstrate no aging effects. Internal surfaces of carbon steel components exposed to ventilation environment have no aging effects. External surfaces of carbon steel exposed to yard and sheltered environments demonstrate the aging effect of loss of material. Brass and copper exposed to ventilation and sheltered environments show no aging effects.

3.3.13.1.2 Aging Management Programs

The Inspection Program for Civil Engineering Structures and Components is utilized to manage aging effects for the diesel generator crankcase vacuum system. A description of the aging management program is provided in LRA Appendix B. The applicant concludes that the effects of aging associated with the components of the diesel generator crankcase vacuum system will be adequately managed by the aging management program during the period of extended operation.

*3.3.13.2 Staff Evaluation*

The applicant described its AMR of the diesel generator crankcase vacuum system for license renewal in two separate sections of its LRA, Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator crankcase vacuum system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.13.2.1 Aging Effects

The aging effects that result from contact of the diesel generator crankcase vacuum SSCs to the environments described in LRA Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.13.2.2 Aging Management Programs

LRA Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133, state that the Inspection Program for Civil Engineering Structures and Components is credited for managing the aging effects in the diesel generator crankcase vacuum system. The Inspection Program for Civil Engineering Structures and Components 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-17, the staff concludes that the above identified AMP will effectively manage the aging effects of the diesel generator crankcase vacuum system, and that there is reasonable assurance that the intended functions of the diesel generator crankcase vacuum system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.13.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.13 and Table 3.3-17, pages 3.3-131 through 3.3-133. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator crankcase vacuum system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.14 Diesel Generator Fuel Oil System

*3.3.14.1 Technical Information in the Application*

The McGuire diesel generator fuel oil system is relied upon to maintain two trains of fuel oil storage and supply for the emergency diesel generators for a period of operation of no less than 5 days. McGuire UFSAR Section 9.5.4, “Diesel Generator Fuel Oil System,” provides additional information concerning the McGuire diesel generator fuel oil system.

The Catawba diesel generator engine fuel oil system is relied upon to maintain two trains of fuel oil storage and supply for the emergency diesel generators for a period of operation of no less than 7 days. Catawba UFSAR Section 9.5.4, “Diesel Generator Engine Fuel Oil System,” provides additional information concerning the Catawba diesel generator engine fuel oil system.

3.3.14.1.1 Aging Effects

Components of the diesel generator fuel oil system are described in Section 2.3.3.14 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, list individual components of the system, including pump casing, tanks, filters, flame arrestors, flow meters, orifices, strainers, pipes, tubing, and valve bodies. Stainless steel components exposed to an internal environment of oil are subject to the aging effect of loss of material. Exposure of external surfaces of stainless steel to an underground environment causes the aging effects of cracking and loss of material. Exposure of stainless steel to ventilation, yard, and sheltered environments has no aging effect. Exposure of carbon steel to internal and external environments of oil, underground, and sheltered environments is subject to the aging effect of loss of material. Exposure of internal surfaces of carbon steel components exposed to a ventilation environment has no aging effect. Cast iron components exposed to oil (internal) and sheltered (external) environments are subject to the aging effect of loss of material.

3.3.14.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the diesel generator fuel oil system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator fuel oil system will be adequately managed by these aging management programs during the period of extended operation.

### *3.3.14.2 Staff Evaluation*

The applicant described its AMR of the diesel generator fuel oil system for license renewal in two separate sections of its LRA, Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator fuel oil system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.3.14.2.1 Aging Effects

The aging effects that result from contact of the diesel generator fuel oil SSCs to the environments described in LRA Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.3.14.2.2 Aging Management Programs

LRA Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141, state that the following aging management programs are credited for managing the aging effects in the diesel generator fuel oil system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection

The Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, and Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Tables 3.3-18 and 3.3-19, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator fuel oil system, and that there is reasonable assurance that the intended functions of the diesel generator fuel oil system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### *3.3.14.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.14 and Tables 3.3-18 and 3.3-19, pages 3.3-134 through 3.3-141. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator fuel oil system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.15 Diesel Generator Lube Oil System

#### *3.3.15.1 Technical Information in the Application*

The McGuire and Catawba diesel generator lube oil systems are essentially the same and perform the same function. The diesel generator lube oil system supplies lubricating oil to the diesel engine and its bearings, crankshaft, thrust faces, and other friction surfaces during both the standby mode and operation mode of the diesel generator. McGuire UFSAR Section 9.5.7, “Diesel Generator Lubricating Oil System,” provides additional information concerning the McGuire diesel generator lube oil system. Catawba UFSAR Section 9.5.7, “Diesel Generator Engine Lube Oil System,” provides additional information concerning the Catawba diesel generator engine lube oil system.

##### 3.3.15.1.1 Aging Effects

Components of the diesel generator lube oil system are described in Section 2.3.3.15 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, list individual components of the system, including pump casing, oil coolers, tanks, flexible hoses, strainers, oil filters, oil heaters, pipes, tubing, and valve bodies. Stainless steel components exposed to internal or external oil and sheltered environments are not subject to any aging effects. Carbon steel components exposed to an internal environment of treated water are subject to the aging effects of cracking and loss of material. Internal surfaces of carbon steel exposed to oil have no aging effect. Exposure of carbon steel to a sheltered or yard external environment causes loss of material. Cast iron components exposed to an internal environment of oil are not subject to any aging effects, while external surfaces exposed to sheltered environments are subject to loss of material. Copper alloy, copper-nickel, and brass components exposed to a treated water internal environment are subject to cracking and loss of material. Exposure of copper alloy and brass to an external environment of oil has no aging effect.

##### 3.3.15.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the diesel generator lube oil system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator lube oil system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.15.2 Staff Evaluation*

The applicant described its AMR of the diesel generator lube oil system for license renewal in two separate sections of its LRA, Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator lube oil system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.15.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information pertaining to LRA Tables 3.3-16, 3.3-20, and 3.3-21. Table 3.3-16 (pages 3.3-126 to 3.3-130) indicates that the Catawba diesel generator governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. According to Tables 3.3-16, 3.3-20, and 3.3-21 of the LRA, the diesel generator engine lube oil coolers (tubes, tubesheets and/or shells) are listed as subject to an internal/external environment of treated water/oil. The staff requested that the applicant identify where in the LRA the aging effect of loss of material was addressed.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.15-4, the applicant stated that the diesel generator lube oil heater pump casings were within the scope of license renewal (see Section 2.3.3.15.2 of this SER). The following AMR results for these components were provided in the applicant's response:

| **Component Type** | **Component Function** | **Material** | **Internal Environment** / **External Environment** | **Aging Effects** | **Aging Management Programs and Activity** |
|---|---|---|---|---|---|
| D/G Lube Oil Heater Pump Casings | PB | CS | Oil | None Identified | None Required |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |

The aging effects that result from contact of the diesel generator lube oil SSCs to the environments described in the applicant's response to RAI 2.3.3.15-4, LRA Section 2.3.3.15, and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.15.2.2 Aging Management Programs

LRA Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148, state that the following aging management programs are credited for managing the aging effects in the diesel generator lube oil system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program

The Chemistry Control Program and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

The staff reviewed the information in LRA Section 2.3.3.15 and Tables 3.3-20 and 3.3-21, pages 3.3-142 through 3.3-148. During its review, the staff determined that additional information was needed to complete its review.

By letter dated January 23, 2002, the staff requested, in RAI 3.3-3, additional information on Tables 3.3-20 and 3.3-21, "Aging Management Review Results for Diesel Generator Lube Oil System (McGuire Nuclear Station)." These tables indicate that the aging effect of cracking and loss of material in a lube oil environment is managed by the Chemistry Control Program. The scope of this program, as defined in LRA Appendix B, Section B.3.6, only refers to fuel oil environments and not lube oil. The staff asked if the Chemistry Control Program manages the aging effects in a lube oil environment.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in the first paragraph of RAI 3.3-3 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed. The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. The staff finds that the applicant's response to RAI 3.3-3 clarifies and satisfactorily resolves this item.

Based on its review of LRA Tables 3.3-20 and 3.3-21, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator lube oil system, and that there is reasonable assurance that the intended functions of the diesel generator lube oil system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.15.3 Conclusions*

The staff reviewed the information in the applicant's response to RAI 2.3.3.15-4; Sections 2.3.3.15 and B.3.6 of the LRA; and Tables 3.3-18, 3.3-19, 3.3-20 and 3.3-21 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator lube oil system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.16 Diesel Generator Room Sump Pump System

*3.3.16.1 Technical Information in the Application*

The McGuire diesel generator room sump pump system removes leakage from equipment drains in the diesel building, and protects the diesel generators from flooding due to a nuclear service water system pipe rupture in one of the diesel rooms acting simultaneously with a turbine building flood. McGuire UFSAR Section 9.5.10, "Diesel Generator Room Sump Pump System," provides additional information concerning the McGuire diesel generator room sump pump system.

The Catawba diesel generator room sump pump system removes normal leakage and drainage from various equipment in the diesel generator rooms. Catawba UFSAR Section 9.5.9, "Diesel Generator Room Sump Pump System," provides additional information concerning the Catawba diesel generator room sump pump system.

3.3.16.1.1 Aging Effects

Components of the diesel generator room sump pump system are described in Section 2.3.3.16 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-22, pages 3.3-149 through 3.3-150, lists individual components of the system, including pump casings, orifices, pipes, and valve bodies. Stainless steel and carbon steel components exposed to an internal raw water environment experience loss of material. Exposure of stainless steel to sheltered environments is not subject to any aging effects, while exposure of carbon steel to a sheltered or yard external environment demonstrates loss of material. Cast iron components (McGuire) are subject to the aging effect of loss of material when exposed to an internal environment of raw water and a sheltered external environment.

3.3.16.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the diesel generator room sump pump system:

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection
- Sump Pump System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator room sump pump system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.16.2 Staff Evaluation*

The applicant described its AMR of the diesel generator room sump pump system for license renewal in two separate sections of its LRA, Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator room sump pump system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.16.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.22-1, additional information pertaining to Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System." This table indicates that orifices provide the function "PB." Typically, orifices also provide the function listed in Note (1) as "TH." The applicant was asked to explain why orifices in the diesel generator room sump pump system do not provide the function "TH," or to correct the component functions for orifices listed in Table 3.3-22.

In its response dated March 15, 2002, the applicant stated that the system intended function of the diesel generator room sump pump system is to remove the contents of the diesel generator room sump to prevent room flooding that could damage equipment. The orifice included in Table 3.3-22 is located in a normally isolated recirculation line that is only used for testing the diesel generator room sump pumps. Throttling is, therefore, not an intended function of the orifice for license renewal. Since the orifice is only used for test run and not intended as "TH" function for normal operation, the staff finds the applicant's response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.22-2, additional information pertaining to Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System." This table has a Note (3), which implies that portions of the diesel generator room sump pump system may be subject to alternate wetting and drying; however, this note is not used in the table. The applicant was requested to clarify if Note (3) is applicable to Table 3.3-22. If so, the applicant should explain how the aging effects associated with this environment will managed during the period of extended operation.

In its response dated March 15, 2002, the applicant stated that Note (3), which implies some portions of the diesel generator room sump pump system are exposed to an alternate wetting and drying environment, is not applicable to Table 3.3-22 of the LRA. No components in the diesel generator room sump pump system within the scope of license renewal are exposed to an alternate wetting and drying environment, which may concentrate contaminants. The staff finds that the applicant's response clarifies and satisfactorily resolves this item, since the components are not subject to an alternate wetting and drying environment, and the aging effect is not applicable.

The aging effects that result from contact of the diesel generator room sump pump SSCs to the environments described in LRA Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.16.2.2 Aging Management Programs

LRA Section 2.3.3.16 and Table 3.3-22, pages 3.3-149 through 3.3-150, state that the following aging management programs are credited for managing the aging effects in the diesel generator room sump pump system.

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection
- Sump Pump System Inspection

The Galvanic Susceptibility Inspection program, Inspection Program for Civil Engineering Structures and Components, Selective Leaching Inspection (McGuire only) program, and Sump Pump System Inspection program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-22, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator sump pump system, and that there is reasonable assurance that the intended functions of the diesel generator sump pump system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.16.3 Conclusions*

The staff reviewed the information in Section 2.3.3.16 and Table 3.3-22 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator room sump pump system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.17 Diesel Generator Starting Air System

*3.3.17.1 Technical Information in the Application*

The McGuire and Catawba diesel generator starting air systems are essentially the same and perform the same function. The diesel generator starting air system provides fast start capability for the emergency diesel engine by using compressed air to roll the engine until it starts. The diesel generator starting air system also supplies air to the diesel controls to operate and shutdown the engine. McGuire UFSAR Section 9.5.6, “Diesel Generator Starting Air System,” provides additional information concerning the McGuire diesel generator starting air system. Catawba UFSAR Section 9.5.6, “Diesel Generator Engine Starting Air System,” provides additional information concerning the Catawba diesel generator engine starting air system.

3.3.17.1.1 Aging Effects

Components of the diesel generator starting air system are described in Section 2.3.3.17 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, list individual components of the system, including air filters, tanks, coolers, flow meters, moisture separators, orifices, silencers, y-strainers, expansion joints, pipes, tubing, and valve bodies. Exposure of stainless steel to a sheltered external environment has no aging effect. Exposure of external surfaces of carbon steel to sheltered environments demonstrates loss of material. Stainless steel and carbon steel exposed to an internal environment of dry air has no aging effect. Exposure of stainless steel and carbon steel to a raw water environment demonstrates loss of material. Exposure of stainless steel and carbon steel to moist air environments has no aging effect. Monel 400 components exposed to an internal environment of raw water are subject to loss of material, while the same components exposed to an external environment of moist air have no aging effects.

3.3.17.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the diesel generator starting air system:

- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (Catawba only)
- Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air (Catawba only)

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the diesel generator starting air system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.17.2 Staff Evaluation*

The applicant described its AMR of the diesel generator starting air system for license renewal in two separate sections of its LRA, Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the diesel generator starting air system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.17.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-1, additional information pertaining to Table 3.3-24, "Aging Management Review Results — Diesel Generator Starting Air System (Catawba Nuclear Station)." This table identifies only a PB function for the diesel generator engine starting air aftercooler tubes. The applicant was requested to explain why the heat transfer (HT) function, which ensures the system and/or component operating temperatures are maintained, is not considered in the AMR, or to correct the component functions for diesel generator engine starting air aftercooler tubes listed in Table 3.3-24 of the LRA.

In its response dated March 15, 2002, the applicant stated that the diesel generator starting air aftercooler is not required to transfer heat for the safety-related diesel to perform its function. The diesel generator starting air aftercooler, and associated piping and components, are non-safety-related because they are not required to function for the diesel to start and operate. The aftercooler is within the scope of license renewal because both sides of the cooler have a pressure boundary function. The pressure boundary of the cooling water side of the aftercooler is safety-related because it forms a pressure boundary of the safety-related nuclear service water system and is, therefore, within scope. The pressure boundary of the air side of the aftercooler is non-safety-related, but is seismically designed and designated Class F. Therefore, the pressure boundary of the air side of the aftercooler meets the criteria of 10 CFR 54.4(a)(2) and is within scope. The Class F design was applied to the system to minimize the effort to regain the diesel in a post seismic situation. Since the aftercooler is not required to transfer heat during the startup of the diesel generator, the staff agrees that HT function is not a required function.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-2, additional information pertaining to Table 3.3-24, of the LRA, "Aging Management Review Results — Diesel Generator Starting Air System (Catawba Nuclear Station)." This table indicates that the Diesel generator engine starting air aftercooler tubes are made of stainless steel, and are subject to loss of material from exposure to a raw water internal environment. Typically, the aging effect, fouling, is also associated with raw water environments. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of fouling to these components, or to provide a justification for excluding this aging effect from Table 3.3-24 of the LRA and an AMR.

In its response dated March 15, 2002, the applicant stated that fouling can cause a loss of heat transfer function, but does not affect the pressure boundary function of the diesel generator starting air system aftercooler tubes. As discussed in the response to RAI 3.3.24-1 above, heat transfer is not a component intended function of the aftercooler tubes. The staff agrees with the applicant that fouling is not an applicable aging effect since heat transfer is not an intended function that meets the scoping criteria of 10 CFR 54.4.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-4, additional information pertaining to Table 3.3-24, of the LRA, "Aging Management Review Results — Diesel Generator Starting Air System (Catawba Nuclear Station)." This table identifies several components where carbon steel is exposed to an air (moist) environment with no aging effects or aging management program required. Loss of material from general, pitting, and crevice corrosion is an applicable aging effect for carbon steel materials in air environments containing moisture. General corrosion results from chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. The applicant was requested to identify where in the LRA the AMR results are for these aging effects, or to provide a justification for excluding these aging effects from LRA Table 3.3-24.

In its response dated March 15, 2002, the applicant stated that LRA Table 3.3-24 presents the results of the aging management review for the diesel generator starting air system. Loss of material due to crevice, general, galvanic, and pitting corrosion was evaluated for the diesel generator starting air system carbon steel components exposed to moist air. Duke determined that crevice, galvanic, and pitting corrosion were not a concern for the period of extended operation. Crevice and pitting corrosion are a concern in air environments where surfaces are alternately wetted and dried, which could concentrate contaminants. Galvanic corrosion occurs in an air environment when dissimilar materials are wet. These conditions do not exist in the moist air portion of the diesel generator starting air system.

Duke considered loss of material due to general corrosion of the carbon steel components, and determined that it was not an aging effect requiring management during the period of extended operation. Absent other influences, such as wetting and drying, general corrosion of carbon steel occurs at a slow rate. The entire diesel generator starting air system is located in the same room with the diesel engines and is normally in standby. The system draws air from the diesel room to charge the tanks. The diesels are warmed to 125 °F and that results in a room temperature of around 100 °F. The air environment inside the system, before the dryers, can be characterized as stagnant warm air of a low humidity. This environment would not promote aggressive general corrosion that could result in a loss of the component intended function if left unmanaged for the period of extended operation. Therefore, loss of material due to general corrosion of the carbon steel components exposed to moist air is not an aging effect requiring management during the period of extended operation. Since the applicant stated that the air environment inside the system, before the dryers, can be characterized as stagnant warm air of a low humidity, the staff agrees that localized and general corrosion are very unlikely to occur.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-5, additional information pertaining to LRA Table 3.3-24, "Aging Management Review Results — Diesel Generator Starting Air System (Catawba Nuclear Station)." This table identifies air (dry) and air (moist) as potential environments for the diesel generator starting air system. Descriptions for these environments are not provided in LRA Section 3.3.1, "Aging Management Review Results Tables." The applicant was requested to identify where in the LRA these environments are defined, or to provide additional information in LRA Section 3.3.1.

In its response dated March 15, 2002, the applicant stated that the two environments, air (moist) and air (dry), were provided in LRA Table 3.3-24 to show that the air environment was not the same throughout the diesel generator starting air system. Both of these air environment variations are bounded by the “Air-Gas” environment definition in Section 3.3.1 of the LRA. The diesel generator starting air system takes air from the diesel room. The air is filtered, compressed, dried, and stored in tanks to be used to start the diesels. The air (moist) environment is the environment prior to the air dryers. The air (dry) environment is the environment after the air dryers.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff indicated that the applicant's response addressed the original question dealing with defining the air (moist) and air (dry) environmental conditions. However, the initial RAI attempted to determine why no aging effects were identified for carbon steel in the air (moist) environment. Aging mechanisms and rates can vary depending on the moisture content in these environments. The staff requested that the applicant provide additional detail to address aging effects under the air (moist) environment.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant replied that Duke believes that characterizing the environment as moist air is misleading. The applicant noted its initial response, in which it stated that the diesel generator starting air system takes air from the diesel room. Since the diesels are heated, the moist air of the diesel rooms is in excess of 100 °F and has a low relative humidity. The diesel generator starting air system filters, compresses, and further dries this air for storage in the system tanks for later use. The diesel room air does not preclude loss of material, but does not promote the aggressive corrosion that, left unmanaged, could result in a loss of the intended function(s) of the components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this explanation in official correspondence. The applicant confirmed that the diesel starting air system components are exposed to an environment with low relative humidity, and that the diesel generator starting air system filters, compresses, and further dries this air for storage in the system tanks for later use. The staff finds that, since the diesel room air does not promote the aggressive corrosion that could result in a loss of the intended function(s) of the system components, this issue is resolved.

In its April 15, 2002, response to RAI 2.3.3.17-2, the applicant determined that the diesel generator starting air distributor filter was within the scope of license renewal (see Section 2.3.3.17.2 of this SER). The following AMR results for this component were provided in the applicant’s response:

| **Component Type** | **Component Function** | **Material** | **Internal Environment / External Environment** | **Aging Effect** | **Aging Management Programs and Activities** |
|---|---|---|---|---|---|
| Starting Air Distributor Filter | PB | CS | Air (Dry) / Sheltered | None Identified / None Identified | None Required / None Required |

The staff finds that the applicant's AMR results are not consistent with the other carbon steel components in a sheltered environment, which the applicant indicated (in the LRA) are subject to the aging effect of loss of material. Since the applicant has not identified this aging effect for the diesel generator starting air distributor filter, and credited an AMP to manage this aging effect, the staff finds that the aging effect (none) listed is not appropriate for the combination of material and environment identified. Therefore, this issue was characterized as SER open item 3.3.17.2.1-1.

In its response dated October 28, 2002, the applicant provided the following revised AMR results table for the diesel generator starting air distributor filter:

| **Component Type** | **Component Function** | **Material** | **Internal Environment / External Environment** | **Aging Effect** | **Aging Management Programs and Activities** |
|---|---|---|---|---|---|
| Starting Air Distributor Filter | PB | CS | Air (Dry) / Sheltered | None Identified / Loss of Material | None Required / Inspection Program for Civil Engineering Structures and Components |

The applicant's response to SER open item 3.3.17.2.1-1 specifies loss of material as an aging effect for the carbon steel starting air distributor filter, and credits the Inspection Program for Civil Engineering Structures and Components. The aging effect specified is consistent with industry experience for the combination of materials and environments identified. Therefore, this response is acceptable to the staff and resolves open item 3.3.17.2.1-1.

The staff finds that the applicant's responses to SER open item 3.3.17.2.1-1, and to RAIs 3.3.24-1, 3.3.24-2, 3.3.24-4, and 3.3.24-5, clarify and satisfactorily resolve these items. The aging effects that result from contact of the diesel generator starting air SSCs to the environments described in LRA Section 2.3.3.17 and LRA Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, and with the resolution of open item 3.3.17.2.1-1, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.17.2.2 Aging Management Programs

LRA Section 2.3.3.17 and Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157, and subsequent correspondence from the applicant, state that the following aging management programs are credited for managing the aging effects in the diesel generator starting air system.

- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (Catawba only)
- Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air (Catawba only)

The Inspection Program for Civil Engineering Structures and Components and Service Water Piping Corrosion Program (Catawba only) are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's evaluation of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air (Catawba only) program follows.

Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air Program (Catawba only)

The applicant described its Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air in Section B.3.17.5 of LRA Appendix B. The staff reviewed the LRA to determine whether the applicant had 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 Catawba. Because of the different materials and environments of the McGuire diesel generator starting air system components, the aging effects are not the same as those that are found at Catawba. The only aging effect at McGuire is loss of material for subject piping and tanks, which is managed by the Inspection Program for Civil Engineering Structures and Components.

Section B.3.17.5 of LRA Appendix B provides a description of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air. The stated purpose of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air is to manage loss of material for parts of the diesel generator engine starting air aftercoolers that are exposed to raw water. The applicant described the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air as a 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. The applicant credits the program with managing loss of material for carbon steel and stainless steel materials.

The staff's evaluation of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air 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.

[Program Scope] As described in the LRA, the scope of the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air includes the tubes and channel heads of the diesel generator engine starting air aftercooler. The staff finds the scope of this activity to be acceptable because it includes those components important to assuring that the pressure boundary is maintained.

[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, not to prevent such loss.

[Parameters Monitored or Inspected]  In conducting the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air program, the applicant inspects the aftercooler tube and channel head surfaces for loss of material.  The staff finds this approach to be acceptable because it will allow the applicant to identify material loss and take corrective action prior to loss of component function.

[Detection of Aging Effects]  The applicant stated that based on information provided under the Monitoring and Trending section, the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air program will detect loss of material due to crevice, galvanic, general, pitting, microbiologically influenced corrosion, and loss of material due to particle erosion prior to loss of the component intended function.  The staff's review found this acceptable, because the applicant performs visual inspections of the channel head surface using a boroscope (for tubes), which is a standard industry method.  The staff agrees that the program is capable of detecting and correcting aging degradation before loss of component function.

[Monitoring and Trending]  As described in the application, the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air manages loss of material of the tubes and channel heads by means of two visual inspections.  Loss of material of the tube internal surfaces is managed by an annual inspection.  This inspection uses a boroscope to visually inspect the tubes.

The applicant stated that loss of material of the channel heads is managed by an annual visual inspection of the protective coatings to assure the integrity of the underlying base metal.  The channel heads of the diesel generator engine starting air aftercoolers are coated with a high solids epoxy.  The coating inspection specifically identifies rust blooms, which indicate a coating defect and corrosion of the base metal.

The applicant takes no actions as part of this activity to trend inspection results.  The staff did not identify the need for trending actions.  The staff finds that the annual inspections are capable of identifying loss of material or other aging effects prior to loss of component function.

[Acceptance Criteria]  The applicant stated that the acceptance criteria for the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air is no unacceptable loss of material of the tubes and channel heads 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, and this issue was characterized as SER open item 3.0.3.9.1.2(g).

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.

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 its operating experience associated with the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air program has demonstrated that visual inspection of the aftercooler tubes and channel heads provides adequate information, in regards to wall loss present in the aftercooler components, to predict when corrective action is required.  Corrective action in the form of tube plugging or coating repair, for example, is performed before the loss of the component intended function. Results of the inspection have led the applicant to replace the aftercooler tubes and the coating of the tubesheets and channel heads.  The applicant stated that original equipment Monel tubes in the diesel generator engine starting air aftercoolers were retubed with stainless steel in 1996 and 1997.  Monel tubes had shown signs of serious pitting damage.  According to the applicant, the replacement stainless steel tubes are also showing signs of pitting as well, but to a lesser degree than the Monel, and are being evaluated for retubing.

The applicant's operating experience has demonstrated that the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air program is an effective program for managing the effects of aging.  The program, with its proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls, accurately predicts aging effects due to corrosion and erosion.

FSAR Supplement:  In LRA Appendix A-2, Section 18.2.12.5, the applicant has provided proposed FSAR supplement for Catawba.  This program will be applied only at Catawba.  The staff reviewed this information and found it to be consistent with the information provided in LRA Appendix B, Section B.3.17.17.5, and, therefore, acceptable.

During its review of information in LRA Section 2.3.3.17; Tables 3.3-23 and 3.3-24, pages 3.3-151 through 3.3-157; and LRA Section B.3.17.5, the staff identified the need for additional information pertaining to this AMP.  By letter dated January 23, 2002, the staff requested, in RAI 3.3.24-3, additional information pertaining to Table 3.3-24, "Aging Management Review Results — Diesel Generator Starting Air System (Catawba Nuclear Station)."  This table identifies the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air as the aging management program to manage the aging effect of loss of material in a raw water environment for the diesel generator engine starting air aftercooler tubes and channel head, but not the tubesheet, which is Monel 400 material.  Section 18.2.12.5 of the FSAR supplement, "Diesel Generating Starting Air," credits this program for managing aging of carbon steel, stainless steel, and Monel materials.  The applicant was asked if the Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air program manages the aging effect loss of Monel 400 material to the diesel generator engine starting air aftercooler tubesheet exposed to a raw water environment.  If not, the applicant was requested to explain the intent of statements made in Section 18.2.12.5 of the FSAR supplement, "Diesel Generating Starting Air," which indicates that this program is credited for managing aging of carbon steel, stainless steel, and Monel materials.

In its response dated March 15, 2002, the applicant stated that Table 3.3-24 and Appendix B (B.3.17.5) of the LRA are correct.  The Heat Exchanger Preventive Maintenance Activities — Diesel Generator Engine Starting Air is not credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler.  The Service Water Piping Corrosion Program is credited with managing loss of material of the Monel 400 tubesheets of the diesel generator starting air aftercooler, as indicated in Table 3.3-24.  Section 18.2.12.5 of the Catawba FSAR supplement is in error and will be revised.  The staff has reviewed the

Service Water Piping Corrosion Program and agrees that it will appropriately manage loss of material of the Monel 400 tubesheets. The staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The staff has reviewed the information in Section B.3.17.5 of LRA Appendix B. On the basis of this review and the above evaluation, and with the resolution of SER open item 3.0.3.9.1.2(g), the staff finds that there is reasonable assurance that the applicant has demonstrated that the effects of aging associated with the Preventive Maintenance Activities — Diesel Generator Engine Starting Air Heat Exchangers 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).

Based on its review of Tables 3.3-23 and 3.3-24 and LRA Appendix B, the staff concludes that the above identified AMPs will effectively manage the aging effects of the diesel generator starting air system, and that there is reasonable assurance that the intended functions of the diesel generator starting air system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.17.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.17; Tables 3.3-23 and 3.3-24; and Section B.3.17.5 of LRA Appendix B. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the diesel generator starting air system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.18 Drinking Water System

#### *3.3.18.1 Technical Information in the Application*

No portion of the McGuire drinking water system is within the scope of license renewal. Only the Duke Class F portions of the drinking water system are in scope at Catawba. McGuire has no Class F components in the drinking water system.

The Catawba drinking water system is a municipal water system consisting of a water tower, pumps, and chemical treatment equipment providing chlorinated drinking water to the plant. The drinking water system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2).

##### 3.3.18.1.1 Aging Effects

Components of the drinking water system are described in Section 2.3.3.18 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-25, page 3.3-158, of the LRA lists individual components of the system, including pipes and valve bodies.

Stainless steel components exposed to an internal treated water environment are subject to the aging effects of cracking and loss of material. Exposure of the same stainless steel components to a sheltered external environment has no aging effect.

3.3.18.1.2 Aging Management Programs

The Treated Water Systems Stainless Steel Inspection is utilized to manage aging effects for the drinking water system. A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the drinking water system will be adequately managed by the aging management program during the period of extended operation.

*3.3.18.2 Staff Evaluation*

The applicant described its AMR of the drinking water system for license renewal in two separate sections of its LRA, Section 2.3.3.18 and Table 3.3-25, page 3.3-158. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the drinking water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.18.2.1 Aging Effects

The aging effects that result from contact of the drinking water SSCs to the environments described in Section 2.3.3.18 and Table 3.3-25, page 3.3-158, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.18.2.2 Aging Management Programs

Section 2.3.3.18 and Table 3.3-25, page 3.3-158, of the LRA state that the Treated Water Systems Stainless Steel Inspection is credited for managing the aging effects in the drinking water system. The Treated Water Systems Stainless Steel Inspection 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-25, the staff concludes that the above identified AMP will effectively manage the aging effects of the drinking water system, and that there is reasonable assurance that the intended functions of the drinking water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.18.3 Conclusions*

The staff reviewed the information in Section 2.3.3.18 and Table 3.3-25, page 3.3-158, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the drinking water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.19 Fire Protection System

#### *3.3.19.1 Technical Information in the Application*

The McGuire and Catawba interior/exterior fire protection systems are essentially the same and perform the same function.  The interior/exterior fire protection systems provide fire suppression to protect the capability to shut down the reactor and maintain it in a safe shutdown condition, and to minimize radioactive releases to the environment in the event of a fire.  In addition, the system provides water to the condenser circulating water pump and low-level intake pump bearings.  McGuire UFSAR Section 9.5.1, “Fire Protection System,” provides additional information concerning the McGuire interior/exterior fire protection system.  Catawba UFSAR Section 9.5.1, “Fire Protection System,” provides additional information concerning the Catawba interior/exterior fire protection system.

##### 3.3.19.1.1 Aging Effects

Components of the fire protection systems are described in Section 2.3.3.19 of the LRA as being within the scope of license renewal and subject to an AMR.  The applicant also provided AMR results tables in letters dated October 28, 2002, and November 18, 2002.  LRA Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, list individual components of the system, including cylinders, tanks, hose racks, flexible hoses, pressure switches, rupture discs, spray nozzles, sprinklers, orifices, dampeners, pump casings, standpipes, pipes, and valve bodies.

Stainless steel components exposed to raw water environments are subject to loss of material. Stainless steel components exposed to ventilation, reactor building, sheltered, and yard environments demonstrate no aging effects.  Internal or external surfaces of carbon steel exposed to raw water, sheltered, yard, underground, or reactor building environments demonstrate the aging effect of loss of material.  Exposure of carbon steel to ventilation or gas environments has no aging effect.  Cast iron components exposed to internal or external raw water, underground, yard, or sheltered environments are subject to loss of material.  Cast iron exposed to a ventilation environment is not subject to any aging effects.

Galvanized steel exposed to raw water, yard, underground, or sheltered internal or external environments is subject to loss of material.  Internal or external surfaces of galvanized steel exposed to ventilation or embedded environments demonstrate no aging effects.  External surfaces of alloy steel exposed to sheltered environments are subject to loss of material.  Alloy steel exposed to a gas environment has no aging effect.  Brass components exposed to external sheltered, yard, or reactor building environments demonstrate loss of material, while the same components exposed to internal ventilation or gas environments show no aging effects.  Brass components exposed to raw water environments are subject to fouling and loss of material.

Copper, malleable iron, and ductile iron components exposed to sheltered environments are subject to loss of material. Exposure of copper, malleable iron, and ductile iron components to ventilation environments demonstrate no aging effects. Bronze components exposed to internal environments of raw water are subject to fouling and loss of material. Bronze components exposed to ventilation, sheltered, or gas environments are not subject to any aging effects. External surfaces of bronze exposed to a sheltered, yard, or reactor building environments are subject to loss of material.

In its response to SER open item 2.3.3.19-2, dated October 28, 2002, the applicant provided the AMR results for fire protection pressure maintenance subsystem SSCs that were identified as within the scope of license renewal. Components of the subsystem include pipes, pump casings, pump strainer housings, strainer baskets, tanks, fire hose racks, and valve bodies. The brass fire hose rack external surface is exposed to a sheltered environment. No aging effects were identified. Loss of material is not an aging effect for this component because the fire hose rack is located in the turbine building and is not subject to any contact with borated water.

In its response to SER open item 2.3.3.19-3, the applicant provided AMR results for the fixed fire suppression equipment to the Catawba lower containment carbon filters. In its response to SER open item 2.3.3.19-6, the applicant provided AMR results for the fixed fire suppression equipment to the Catawba lower containment carbon filters, and for manually operated water spray systems to the McGuire reactor building purge exhaust filters 1A, 1B, 2A, and 2B.

In its response to SER open item 2.3.3.19-5, the applicant provided the following AMR results:

| **Component Type** | **Component Function (Note 1)** | **Material** | **Internal Environment (Note 1)**<br>**External Environment (Note 2)** | **Aging Effect** | **Aging Management Program and Activity (Note 3)** |
|---|---|---|---|---|---|
| Main Fire Pump Strainers | Filtration | Bronze or Stainless Steel | Raw Water (Note 2) | Loss of Material | Fire Protection Program - Main Fire Pump Strainer Inspection |

Notes:
(1) Filtration - Provide filtration of process fluid so that downstream equipment and/or environments are protected.
(2) The Main Fire Pump Strainers are located on the suction side of the pumps, totally immersed in raw water.

In its response to SER open item 2.3.3.19-4, dated November 18, 2002, the applicant provided the following AMR results:

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effect | Aging Management Program and Activity (Note 3) |
|---|---|---|---|---|---|
| Fire Hose Rack | Pressure Boundary | Brass | Ventilation | None Identified | None Required |
| | | | Sheltered | None Identified | None Required |
| Piping | Pressure Boundary | Galvanized Steel | Raw Water | Loss of Material | Service Water Piping Corrosion Program<br><br>Galvanic Susceptibility Program |
| | | | Sheltered | None Identified | None Required |
| Valves | Pressure Boundary | Bronze | Raw Water | Fouling | Fire Protection Program |
| | | | | Loss of Material | Service Water Piping Corrosion Program |
| | | | Sheltered | None Identified | None Required |

3.3.19.1.2 Aging Management Programs

The following AMPs are credited to manage aging effects for the interior/exterior fire protection systems:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Galvanic Susceptibility Inspection
- Service Water Piping Corrosion Program
- Fire Protection Program — Mechanical Fire Protection Component Tests and Inspections
- Selective Leaching Inspection
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection

In letters dated October 28, 2002, and November 18, 2002, the applicant credited the following three new aging management programs:

- Fire Protection Program — Main Fire Pump Strainer Inspection
- Fire Protection Program — Jockey Pump Strainer Inspection
- Fire Protection Program — Tank and Connected Piping Internal Inspection
- Fire Protection Program — Turbine Building Manual Hose Station Flow Test

A description of these aging management programs is provided in Appendix B of the LRA and in October 28, 2002, and November 18, 2002, correspondence from the applicant. The applicant concludes that the effects of aging associated with the components of the interior/exterior fire protection systems will be adequately managed by these aging management programs during the period of extended operation.

*3.3.19.2 Staff Evaluation*

The applicant described its AMR of the fire protection systems for license renewal in two separate sections of its LRA, Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the fire protection system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.19.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191. The staff also reviewed the AMR results tables provided in letters from the applicant dated October 28, 2002, and November 18, 2002. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.26-1, additional information pertaining to Table 3.3-26, of the LRA, “Aging Management Review Results — Fire Protection System (McGuire Nuclear Station).” This table indicates that sprinklers have a spray flow function. The last sprinkler component in LRA Table 3.3-26 (page 3.3-164) is missing the SP (spray flow) designation. The applicant was requested to correct the table, or justify why the spray flow function is not applicable to these sprinkler entries.

In its response dated March 15, 2002, the applicant stated that the last sprinkler entry in Table 3.3-26 (page 3.3-164) of the LRA should have contained the SP designation. The programs listed for this sprinkler will serve to manage the SP function consistent with other, similar entries in Table 3.3-26 of the LRA. Since the applicant has indicated that the SP function is applicable, the staff finds this response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.26-2, additional information pertaining to information in LRA Table 3.3-26, “Aging Management Review Results — Fire Protection System (McGuire Nuclear Station).” Table 3.3-26 states that the fire protection program is credited with managing the aging effect of fouling in raw water environments for carbon steel, brass and bronze valves. Carbon steel, brass, and bronze valve body components are identified in the exterior fire protection section of Table 3.3-26 of the LRA, but fouling has not been identified as an aging effect. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of fouling for these components, or to provide a justification for excluding this aging effect from Table 3.3-26 of the LRA and an AMR.

In its response dated March 15, 2002, the applicant stated that fouling is an applicable aging effect, but only for a specific set of components in the fire protection systems in which a fouled condition could prevent the supply of fire suppression water. As described in Section B.3.12.2, Mechanical Fire Protection Component Tests and Inspections of LRA Appendix B, fouling is managed for specific distribution components of the fire protection systems (sprinklers, hose station valves, and hydrant valves). Managing the impact of fouling on these components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components. In the interior fire protection system at McGuire, fouling is an applicable aging effect for sprinklers and brass and bronze hose station valves exposed to raw water. In the exterior fire protection system at McGuire, fouling is not an applicable aging effect for the cast iron hydrant valves exposed to raw water because no cast iron hydrant valves are relied upon for fire suppression distribution. This latter point differs from Catawba, where hydrant valves are relied upon for fire suppression distribution, and for which fouling is an applicable aging effect. Since there are no cast iron hydrant valves relied upon for fire suppression distribution at McGuire, the staff finds this response acceptable.

The applicant also stated that, upon further review of Table 3.3-26 of the LRA and consistent with this discussion, an error exists in the McGuire exterior fire protection portion of the table. Fouling should not be an applicable aging effect for the cast iron valve bodies in the yard and exposed to raw water. The LRA Table 3.3-26 entry for the cast iron valve bodies in the yard and exposed to raw water was revised to reflect this. The staff believes that this revision clarifies the item.

By letter dated January 23, 2002, the staff requested, in RAI-3.3.26-3, additional information pertaining to LRA Table 3.3-27, "Aging Management Review Results — Fire Protection System (Catawba Nuclear Station)." This table indicates that Note (4) is applicable in several locations in the table where components are subject to the aging effect fouling. There is no definition for Note (4) at the end of Table 3.3-27. The applicant was requested to clarify if Note (4) is applicable to Table 3.3-27 and, if so, to define it.

In its response dated March 15, 2002, the applicant stated that Note 4 applies to LRA Table 3.3-27. The note was inadvertently omitted from the table notes. Note 4 should read "Fire Hose Rack Valves Only." Upon further review of the LRA Table 3.3-27, an additional notation error was discovered. The fouling entry on page 3.3-189 of the LRA should contain a Note 5 instead of Note 4. Note 5 should read "Fire Hydrant Valves Only." Since the applicant corrected the error, the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

In its response to SER open item 2.3.3.19-2, dated October 28, 2002, the applicant provided the AMR results for fire protection pressure maintenance subsystem SSCs that were identified as within the scope of license renewal. Components of the subsystem include pipes, pump casings, pump strainer housings, strainer baskets, tanks, fire hose racks, and valve bodies. The brass fire hose rack external surface is exposed to a sheltered environment. No aging effects were identified. Loss of material is not an aging effect for this component because the fire hose rack is located in the turbine building, and is not subject to any contact with borated water. For other components of the fire protection pressure maintenance subsystem, the material and environment combinations are the same as those specified in LRA Tables 3.3-26 and 3.3-27. The aging effects identified were consistent with those described in the preceding paragraphs of this SER section.

In its response to SER open item 2.3.3.19-3, the applicant provided AMR results for the fixed fire suppression equipment to the Catawba lower containment carbon filters. In its response to SER open item 2.3.3.19-6, the applicant provided AMR results for the fixed fire suppression equipment to the Catawba lower containment carbon filters, and for manually operated water spray systems to the McGuire reactor building purge exhaust filters 1A, 1B, 2A, and 2B. For both responses, the components, materials, environments, aging effects, and AMPs credited were consistent with those specified in AMR results tables for McGuire and Catawba interior fire protection systems provided in the LRA.

The staff reviewed these AMR results provided in response to SER open item 2.3.3.19-4, and determined that the components, materials, environments, aging effects, and AMPs credited were consistent with those specified in AMR results tables for McGuire and Catawba interior fire protection systems provided in the LRA.

The aging effects that result from contact of the fire protection SSCs to the environments described in LRA Section 2.3.3.19 and LRA Tables 3.3-26 and 3.3-27, and in correspondence from the applicant, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.19.2.2 Aging Management Programs

LRA Section 2.3.3.19 and Tables 3.3-26 and 3.3-27, pages 3.3-159 through 3.3-191, state that the following aging management programs are credited for managing the aging effects in the fire protection system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Galvanic Susceptibility Inspection
- Service Water Piping Corrosion Program
- Fire Protection Program — Mechanical Fire Protection Component Tests and Inspections
- Selective Leaching Inspection
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection

In response to SER open items pertaining to scoping and screening of fire protection equipment (documented in Section 2.3.3.19 of this SER), the applicant provided the following AMPs in letters dated October 28, 2002, and November 18, 2002.

- Fire Protection Program — Main Fire Pump Strainer Inspection
- Fire Protection Program — Jockey Pump Strainer Inspection
- Fire Protection Program — Tank and Connected Piping Internal Inspection
- Fire Protection Program — Turbine Building Manual Hose Station Flow Test

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Service Water Piping Corrosion Program, Inspection Program for Civil Engineering Structures and Components, Fire Protection Program, Selective Leaching Inspection Program and Liquid Waste System Inspection Program, and Preventive Maintenance Activities — Condenser Circulating Water System Internal Coating Inspection Program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. The staff's review of the Fire Protection Program — Mechanical Fire Protection Component Tests and Inspections, the Fire Protection Program — Main Fire Pump Strainer Inspection, the Fire Protection Program — Jockey Pump Strainer Inspection, the Fire Protection Program — Tank and Connected Piping Internal Inspection, and the Fire Protection Program — Turbine Building Manual Hose Station Flow Test follows.

Fire Protection Program — Mechanical Fire Protection Component Tests and Inspections

The applicant described its Mechanical Fire Protection Component Tests and Inspections in Section B.3.12.2 of LRA Appendix B. The applicant credits these activities with managing the potential aging of specific fire protection system components that are within the scope of license renewal. The staff reviewed Section B.3.12.2 of LRA Appendix B to determine whether the applicant has demonstrated that tests and inspections of mechanical fire protection components will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Section B.3.12.2 of LRA Appendix B describes the Mechanical Fire Protection Component Tests and Inspections. The purpose of this program is to manage loss of material and fouling of specific components in the fire protection systems. The program manages loss of material in sprinklers that can affect the pressure boundary and spray functions of the sprinklers. The program also manages fouling of sprinklers, valves at hydrants, and valves at hose racks that can affect the component function. This program is a condition monitoring program that is credited with managing the subject aging effect for brass and bronze materials exposed to a raw water environment.

Operating experience has demonstrated that fouling is an aging effect requiring management for the fire protection systems at McGuire and Catawba. The systems use lake water as their water source. The stations have been working to manage fouling through the use of chemical treatment, testing, and inspections. For the purpose of license renewal, fouling is being applied to the distribution components (sprinklers, hose station valves, and hydrant valves) of the fire protection systems. Managing fouling of the distribution components ensures that the system is capable of performing its function of supplying fire suppression water through the distribution components.

The staff’s evaluation of the program focused on how the program manages the 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 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.

[Program Scope] The components within the scope of the program are the sprinklers and fire hydrant valves and hose rack valves of the interior and exterior fire protection systems. The staff finds the program scope adequate and acceptable.

[Parameters Monitored or Inspected]  The program involves visual inspections to verify sprinkler condition, and flow is monitored during flow tests and flushes of the system to verify that there is no blockage of flow that will prevent system function.  The staff finds that visual inspection will detect loss of material due to general, crevice, and pitting corrosion, as well as loss of seal or cracking due to embrittlement.  Internal conditions are monitored through the use of leakage, flow, and pressure testing.  Internal loss of material (due to general, crevice, and pitting corrosion, microbiologically influenced corrosion, and selective leaching) and blockage due to fouling can be detected by changes in flow or pressure, leakage, or evidence of excessive corrosion products during flushing of the system.  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 stated that detection of degradation on external surfaces is determined by visual examination.  Surfaces of components and structures are examined for damage, deterioration, leakage, or other forms of corrosion.  Section B.3.12.2 of LRA Appendix B states that functional testing and flushing of the system clears away internal scale, debris, and other foreign material that could lead to blockage/obstruction of the system.  Flow and pressure tests verify system integrity.  Visual examination of breached portions of the system also verifies unobstructed flow and integrity of the piping/components.  In response to the staff's RAIs, the applicant stated that volumetric examinations will also be performed, as described below.  The staff finds the detection of aging effects adequate and acceptable.

[Monitoring and Trending]  The program manages loss of material and fouling through visual inspections and system flow tests and flushes.

Section B.3.12.2 of LRA Appendix B states that loss of material of sprinklers is detected through the use of visual inspections.  Sprinklers are visually inspected at least once every 18 months in accordance with SLC 16.9.2.  Additionally, a sample of sprinklers are either inspected or replaced at 50 years of operation.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-1, the applicant to describe the basis for the sampling process for testing and/or replacement of sprinklers after 50 years of operation.  In its response dated March 15, 2002, the applicant indicated that the rationale for replacement or testing comes from NFPA 25 – 1998, Section 2-3.1.1, which states—

> Where sprinklers have been in service for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory acceptable to the authority having jurisdiction for field service testing.

The applicant indicated that samples will be selected based on the different environments (temperature, humidity, etc.) that the sprinklers were exposed to during their 50-year service life.  The staff finds the response acceptable because it conforms to NFPA guidelines.

Section B.3.12.2 of LRA Appendix B states that fouling of hose station valves, hydrant valves, and sprinklers is managed by various flow tests and flushes performed on the systems.  Distribution loops experience high-volume flow when hydrant valves are periodically opened.  This is performed for the outside distribution loop every 6 months, and is governed by SLC 16.9-1(a)(iii) for Catawba and Testing Requirement (TR) 16.9.1.3 for McGuire.  Additional distribution loop flow tests are performed by procedure less frequently.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-2, the applicant to clarify the difference between SLC 16.9.1(a)(iii) at Catawba and TR 16.9.1.3 at McGuire, both of which govern the flow tests and flushes of hose station valves and sprinklers. In its response dated March 15, 2002, the applicant stated that the content of the two requirements is the same; they simply have different numbers. McGuire recently converted their SLC to a standardized Technical Specification format, while Catawba has not yet completed their conversion. Therefore, the surveillance numbering scheme is different between the plants' SLCs. The staff finds this clarification reasonable and acceptable.

Section B.3.12.2 of LRA Appendix B states that the integrity of hose station valves and hydrant valve is assured by supplying water to these components. Each hose station valve is opened at least once every 3 years per SLC 16.9-4. Hydrant valves are fully opened every 6 months. The hydrant tests are not governed by SLCs, but are performed by procedure.

Section B.3.12.2 of LRA Appendix B also states that the integrity of the sprinkler branch lines is assured by performing sprinkler system flow tests every 18 months. This procedure is performed by fully opening the inspector's test connection valve, which stimulates flow from the most hydraulically remote sprinkler head on each system. This test is governed by SLC TR 16.9-2(a)(iv)(1) at Catawba. The test is not governed by SLCs at McGuire, but is performed by procedure.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-3, the applicant to clarify why the sprinkler system flow testing for branch lines is governed by SLC TR 16.9-2(a)(iv) at Catawba, but is performed to satisfy a specific plant procedure at McGuire, and not governed by any SLC. In its response dated March 15, 2002, the applicant stated that during original licensing of McGuire, the sprinkler system flow test was not a required TS surveillance. During subsequent Catawba licensing, the surveillance was required to be placed in Technical Specifications. Since it was never in the original McGuire TS, it was not placed into the SLC during the TS conversion. Since the test is committed to as part of an AMP for license renewal, the sprinkler system flow test will be added to the McGuire FSAR supplement. In its response to RAI B.3.12.2-3, the applicant indicated that the FSAR supplement will be revised to include the sprinkler system flow test in accordance with their response to RAI B.3.2.12.2-4, which is discussed in the following paragraphs. The staff finds the clarification reasonable and acceptable because the integrity of the sprinkler branch lines will be ensured by performance of sprinkler system flow tests on a periodic basis.

Section B.3.12.2 of LRA Appendix B states that fouling of sprinkler branch lines that do not receive flow during this test will be managed by a sample disassembly inspection program. Since these lines do not receive flow, it is believed that they are less susceptible to fouling than the lines that receive flow during testing. To validate this belief, branch lines of a few representative sprinkler systems will be disassembled and the piping visually inspected. Subsequent inspections for the period of extended operation will be determined based on inspection results. If fouling is minimal, it is preferable to terminate the sample inspections because draining and filling activities introduce newly oxygenated water to those portions of the systems; this would have an adverse effect on corrosion and fouling of the lines.

By letter dated January 28, 2002, the staff requested, in RAI B 3.12.2-4, the applicant to explain the basis for the sample disassembly inspection program for managing the fouling of sprinkler branch lines. In its response dated March 15, 2002, the applicant stated that, in light of the view that the potential for general corrosion is accelerated by introducing new oxygen to the system when the system is opened, the applicant would revise this aspect of the program, as described in Section B 3.12.2 of LRA Appendix B. Fouling of sprinkler branch lines that do not receive flow during flow tests was to be managed by disassembling the piping and visually inspecting the interior surfaces. The applicant proposes a combination of volumetric examination, such as radiography, and possibly sample disassembly to manage fouling of these branch lines. Some radiography of the fire protection piping has already been performed and provides excellent indication of corrosion product buildup in the lines. The applicant proposed using volumetric examination as a screening tool to determine if it is necessary to perform further intrusive inspections.

The branch line samples to be inspected by volumetric examination will be selected based on several factors. Samples will be chosen to try to obtain a representative sampling of the various environments (temperatures, flow condition, etc.) to which the sprinkler systems have been exposed. Also, samples will be chosen based on pipe configurations that would lend themselves to worst-case fouling (e.g., low points, multiple bends, etc.). The sample size will be determined based on obtaining a representative sample that would bound all of the selection parameters identified in the applicant's response. The applicant further stated that, if volumetric examination results indicate the need to perform further intrusive inspections on a particular branch line, then that branch line will be inspected as described in the Section B 3.12.2 of LRA Appendix B. The applicant indicated that the FSAR supplements would be updated to reflect this use of volumetric examination in this AMP, and to include the sprinkler system flow test in accordance with its response to RAI B.3.2.12.2-3 (previously discussed). The staff finds this response reasonable and acceptable because fouling of sprinkler branch lines that do not receive flow during periodic testing will be monitored by volumetric examination procedures.

By letter dated January 28, 2002, the staff requested, in RAI B.3.12.2-5, the applicant to indicate if its AMP conforms to the following staff position:

> The staff proposes to revise the fire protection program inspection criteria in NUREG-1801 for wall thinning of piping due to corrosion. Each time the system is opened, oxygen is introduced into the system, and this accelerates the potential for general corrosion. Therefore, the staff recommends that a non-intrusive means of measuring wall thickness, such as ultrasonic inspection, be used to detect this aging effect. The staff recommended action in this regard is that, in addition to an ultrasonic inspection of the fire protection piping before exceeding the current licensing term, the applicant perform ultrasonic inspections immediately after the 50-year service life sprinkler head testing, in accordance with NFPA 25, Section 2.3.3.1, and at 10-year intervals thereafter.

In its response dated March 15, 2002, the applicant provided the following:

> The "Service Water Piping Corrosion Program," discussed in Section B 3.29 of the Application, manages wall thinning of piping due to corrosion of Fire Protection systems. The program uses ultrasonic inspection, a non-intrusive method to manage this effect. The nature of the program does not prescribe inspections at the specified times outlined by the staff position, but does ensure reinspection at an appropriate frequency based on the calculated corrosion rate. (See response to RAI B.3.29-2.) The program will likely impose inspections more frequently than that outlined in the staff's position. The program is an existing program with adequate operating experience to provide reasonable assurance that it will manage the aging of fire protection systems as successfully as it has managed other raw water systems in the plant.

The staff finds the applicant's response reasonable and acceptable since it conforms with the proposed staff position on this issue.

By letter dated January 28, 2002, the staff requested, in RAI B 3.12.2-6, the applicant to describe the environmental and material conditions that exist on the interior surface of below-grade fire protection piping. The staff's position is that if these conditions can be demonstrated to be similar to the conditions existing in the above-grade fire protection piping, then the inspections in the above-grade piping may be extrapolated to evaluate the interior conditions of the below-grade piping. If not, additional inspection activities may be needed to provide reasonable assurance that the intended function of below-grade fire protection piping will be maintained consistent with the applicant's licensing basis for the extended operation.

In its March 15, 2002, response, the applicant stated that the environmental conditions of the interior surface of the below-grade fire protection piping are exactly the same as that of the above-grade fire protection piping. The environment is stagnant lake water. The material conditions of the below-grade fire protection piping are different than those of the above-grade fire protection piping. The below-grade fire protection piping is cement-lined, providing it with an added feature to prevent the loss of material of the base metal due to corrosion. The cement lining also prevents internal buildup of turbucles that would contribute to the degradation of the pipe flow characteristics. In addition to the inspection activities, the testing features described in Section B 3.12.2 of LRA Appendix B involve testing on the below-grade, as well as the above-ground, portion of the system to provide assurance that the entire system can perform its intended function. In addition, the applicant has performed intrusive visual inspections of the internal surfaces of the underground cement-lined piping during maintenance of modification work. The condition of the piping is excellent. The internal lining is intact, ensuring the integrity of the base metal. The staff finds the applicant's response reasonable and acceptable.

The staff finds that the applicant's methodology will provide effective monitoring and trending of the aging effects and is, therefore, acceptable.

[Acceptance Criteria] Section B.3.12.2 of LRA Appendix B describes the acceptance criteria for the visual inspections of the sprinklers as, "an evaluation is performed for any cracks, corrosion, missing pipe hangers, obstructions to sprinkler spray pattern, and other piping abnormalities that are detected." The acceptance criteria for system flushes and slow tests are, "water shall flow through the valve to the discharge point with no obvious signs of flow blockage." The staff finds these acceptance criteria acceptable because the effects of aging will be detected and evaluated before loss of intended function would occur.

[Operating Experience] Section B.3.12.2 of LRA Appendix B describes the operating experience as follows:

> McGuire Operating Experience
> Fouling of the fire protection systems is being minimized by chemical treatment of the water. Additionally, system engineers monitor flow through the system headers and attempt to minimize header flow to reduce internal buildup of corrosion products. Flow tests have not detected unacceptable fouling in other areas where flows are limited. Over the past three years, sections of piping have been replaced due to pin-hole leaks or where fouling has been detected during permitted internal inspections. All corrective actions have been taken prior to loss of component intended function.

Catawba Operating Experience
Fouling of the fire protection systems is being minimized in recent years by chemical treatment of the water. Additionally, system engineers monitor flow through the system headers and attempt to minimize header flow to reduce internal buildup of corrosion products. Due to corrosion product buildup in the system, the Interior Fire Protection System auxiliary building header was cleaned in 1996. All corrective actions have been taken prior to loss of component intended function.

The staff finds that the operating experience at McGuire and Catawba indicates that aging of the fire protection system will be effectively managed during the period of extended operation.

FSAR Supplement: The staff has reviewed the UFSAR Section 18.2.8 of Appendix A to the LRA, and has confirmed that it contains the appropriate elements of the program.

In conclusion, the staff reviewed the information provided in Section B.3.12.2 of LRA Appendix B, the summary description provided in the FSAR supplement, and the applicant's March 15, 2002, responses to the staff's RAIs. On the basis of its review, as discussed above, the staff finds that there is reasonable assurance that the Mechanical Fire Protection Component Tests and Inspections will adequately manage the aging effects, such that the intended function(s) will be maintained in accordance with within the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Fire Protection Program — Main Fire Pump Strainer Inspection</u>

In response to open item 2.3.3.19-5, by letter dated October 28, 2002, the applicant submitted the Main Fire Pump Strainer Inspection program. The purpose of this program is to identify any loss of material of each main fire pump strainer in the fire protection system. The program manages loss of material in the fire pump strainers that prevents debris from entering the pump when it is in operation, thus protecting the pump from damage. This program is a condition monitoring program that is credited with managing the subject aging effect for bronze or stainless steel materials exposed to a raw water environment.

Lake water is used to supply the fire protection suppression systems at McGuire and Catawba. Lake water is corrosive and may contain sediment, which can potentially clog the fire pumps. The pumps are normally in standby and are automatically started on low system pressure. Each pump has a ½ inch mesh strainer, which is located on the suction side of the pump and is totally immersed in raw water. Managing loss of material of the strainer ensures that the raw water is filtered to protect the downstream fire protection equipment and/or components.

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 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:

[Program Scope]  The scope of the Main Fire Pump Strainer Inspection is the strainer located on the suction bell of each main fire pump.  The staff finds the program scope acceptable since the program manages aging for the main fire pump strainers.

[Preventive Actions]  No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation.  The staffs concurs that no preventive actions are required for this condition monitoring program.

[Parameters Monitored or Inspected]  The parameter inspected by the Main Fire Pump Strainer Inspection is loss of material of the stainless steel or bronze strainer due to exposure to a raw water environment.  The staff finds the parameter inspected acceptable since inspection of the strainer will detect the presence, and extent, of the aging effect of loss of material.

[Detection of Aging Effects]  In accordance with information provided for the Monitoring and Trending element (documented below), the Main Fire Pump Strainer Inspection will detect loss of material of the main fire pump strainers by visual inspection performed prior to loss of component intended function.  There is no operating experience for loss of material of these strainers; therefore, the staff finds the visual inspection prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, an acceptable method to detect loss of material in the strainers.  The inspection frequency is based on the planned frequency for performing routine maintenance on each main fire pump.  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.  All strainers will be inspected, therefore sampling is not used as an inspection method.

[Monitoring and Trending]  The Main Fire Pump Strainer Inspection is a general visual inspection for loss of material of the strainer.  The Main Fire Pump Strainer Inspection will be performed at least once every 10 years.  For McGuire, the initial Main Fire Pump Strainer 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 Unit 1).  For Catawba, the initial Main Fire Pump Strainer 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 monitoring (visual inspection) frequency of the strainer which is prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, is acceptable to ensure that the component intended function is maintained during the period of extended operation. No actions are taken as part of this program to trend inspection results.

[Acceptance Criteria]  The acceptance criterion for the Main Fire Pump Strainer Inspection is no unacceptable loss of material that could result in a loss of component intended function(s), as determined by engineering evaluation.  If engineering evaluation determines that the observed aging effects do not cause a loss of component intended function, then no further actions are necessary.  If engineering evaluation determines that the observed aging effects could cause a loss of component intended function, then corrective actions are taken, including cleaning of the strainer or replacement.  Specific corrective actions will be implemented in accordance with the corrective action program.  The staff finds that no unacceptable loss of material that could result in a loss of component intended function(s), as determined by engineering evaluation, is an adequate acceptance criterion.

[Operating Experience]  The Main Fire Pump Strainer Inspection is a new inspection for which there is no operating experience.  The inspection frequency is based on the planned frequency for performing routine maintenance on each main fire pump.  The Main Fire Pump Strainer Inspection is a new program that will use techniques with demonstrated capability and a proven industry record to identify loss of material in a raw water environment.  Similar visual inspections have been used to detect degradation loss of material for piping components.  The staff finds the applicant's inspection method acceptable.

FSAR Supplement:  The staff has reviewed the USFAR Supplement summary description of the Main Fire Pump Strainer Inspection in the applicant's response to open item 2.3.3.19-5, and has confirmed that it contains the appropriate elements of the program.

In conclusion, the staff reviewed the applicant's October 28, 2002, response to open item 2.3.3.19-5.  On the basis of this review, as discussed above, the staff finds that there is reasonable assurance that the Main Fire Pump Strainer 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).

Fire Protection Program — Jockey Pump Strainer Inspection

In response to open item 2.3.3.19-2, by letter dated October 28, 2002, the applicant submitted the Jockey Pump Strainer Inspection program.  The purpose of the Jockey Fire Pump Strainer Inspection is to identify loss of material of each stainless steel jockey pump strainer basket. A strainer is located at the suction side of each jockey pump.  Raw water flow could result in loss of material of the strainer.  This activity visually inspects the condition of the strainer baskets every 10 years to check for loss of material.  The Jockey Pump Strainer Inspection is a condition monitoring activity and is a new plant activity for license renewal.

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 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]  The scope of the Jockey Pump Strainer Inspection is the strainer located on the suction side of each jockey pump.  The staff finds the program scope acceptable since the program manages aging for the jockey pump strainers.

[Preventive Actions]  No actions are taken as part of this program 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] The parameter inspected by the Jockey Fire Pump Strainer Inspection is loss of material due to exposure to a raw water environment. The staff finds the parameter inspected acceptable since inspection of the stainless steel strainer will detect the presence, and extent, of the aging effect of loss of material.

[Detection of Aging Effects] In accordance with information provided for the Monitoring and Trending element (documented below), the Jockey Pump Strainer Inspection will detect loss of material of the jockey pump strainers prior to loss of component intended function. Operating experience has not identified loss of material for the jockey pump strainers. Therefore, the staff finds the visual inspection prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, an acceptable method to detect loss of material in the strainers. If inspections are not acceptable, specific corrective actions will be implemented by the applicant, in accordance with the corrective action program, to ensure that the component intended function will be maintained during the period of extended operation. All strainers will be inspected; therefore, sampling is not used as an inspection method.

[Monitoring and Trending] The Jockey Pump Strainer Inspection is a general visual inspection for loss of material of the strainer baskets. For McGuire, the initial Jockey Pump Strainer 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 Unit 1). For Catawba, the initial Jockey Pump Strainer 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 Unit 1). The staff finds that the monitoring (visual inspection) frequency of the strainer, which is prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, is acceptable to ensure that the component intended function is maintained during the period of extended operation. No actions are taken as part of this program to trend inspection results.

[Acceptance Criteria] The acceptance criterion for the Jockey Pump Strainer Inspection is no unacceptable loss of material that could result in a loss of component intended function(s), as determined by engineering evaluation. If engineering evaluation determines that the observed aging effects do not cause a loss of component intended function, then no further actions are necessary. If engineering evaluation determines that the observed aging effects could cause a loss of component intended function, then corrective actions are taken, including cleaning of the strainer or replacement. Specific corrective actions will be implemented in accordance with the corrective action program. The staff finds that no unacceptable loss of material that could result in a loss of component intended function(s), as determined by engineering evaluation, is an adequate acceptance criterion.

[Operating Experience] The Jockey Pump Strainer Inspection is a new inspection. Visual inspection is an effective method for detecting age-related degradation in the strainers. The strainers have been cleaned periodically through the years and loss of material has not been observed. The staff finds that the applicant’s operating experience provides objective evidence to support the conclusion that the effects of aging will be managed adequately, so that the strainers intended function will be maintained during the period of extended operation.

FSAR Supplement: The staff has reviewed the USFAR Supplement summary description of the Jockey Pump Strainer Inspection in the applicant's response to open item 2.3.3.19-2, and has confirmed that it contains the appropriate elements of the program.

In conclusion, the staff reviewed the applicant's October 28, 2002, response to open item 2.3.3.19-2. On the basis of this review, as discussed above, the staff finds that there is reasonable assurance that the Jockey Pump Strainer 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).

<u>Fire Protection Program — Tank and Connected Piping Internal Inspection</u>

In response to open item 2.3.3.19-2, by letter dated October 28, 2002, the applicant submitted the Tank and Connected Piping Internal Inspection program. The purpose of the Tank and Connected Piping Internal Inspection is to manage loss of material of the internal surfaces of the carbon steel tanks and some connecting piping and valves in the Fire Protection System at McGuire and Catawba and the Filtered Water System at Catawba. The internal carbon steel surfaces of the tanks within the scope of this inspection are coated with an epoxy coating. Continued presence of an intact coating precludes loss of material of the internal surfaces of the carbon steel tanks that could lead to loss of pressure boundary function. This activity inspects the internal coating of the tanks every 10 years to check the condition of the coating to identify coating failures, and inspects some of the connected piping for loss of material. The Tank and Connected Piping Internal Inspection is a condition monitoring activity.

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 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] The scope of the Tank and Connected Piping Internal Inspection is the internal surface of the McGuire fire protection system pressure maintenance accumulator tank and the connecting piping and valves that supply high-pressure air. The scope of the program at Catawba is the equivalent fire protection system pressure maintenance accumulator tank. Additionally, at Catawba, the filtered water tanks, and their connected aluminum piping in the supply system to the fire protection system, will be inspected. The staff finds the program scope acceptable since the program manages aging of the internal surfaces of the tanks and piping for loss of material. Included in the program are the accumulator tank and connecting high-pressure air piping and valves at McGuire, and the accumulator tank and the filtered water tanks and connecting aluminum piping at Catawba.

[Preventive Actions] No actions are taken as part of this program to prevent aging effects or to mitigate aging degradation. The staffs concurs that no preventive actions are required for this condition monitoring program.

[Parameters Monitored or Inspected] The Tank and Connected Piping Internal Inspection inspects the coating for signs of blistering, chipping, peeling, and missing coating, as well as signs of corrosion of the underlying carbon steel tanks. The inspection also visually inspects the high-pressure air supply piping connected to the fire protection system pressure maintenance accumulator tank at McGuire, and the aluminum piping connected to the filtered water tanks at Catawba, for signs of loss of material. Due to the material and environment of this connecting piping, little to no aging effects are expected in these latter components, which will be verified by this inspection. The staff finds the parameters inspected are acceptable since a visual inspection of the tanks and piping will detect the condition of the tank coatings and any loss of material of connecting piping and valves.

[Detection of Aging Effects] In accordance with the information provided for the Monitoring and Trending element (documented below), the Tank and Connected Piping Internal Inspection will detect the condition of the tank coatings and any loss of material of connecting piping. Previous visual inspections of the McGuire tank and a similar tank at Catawba have demonstrated that visual inspection of internal surfaces is an effective method for detecting age-related degradation in the tanks and associated piping and valves. Therefore, the staff finds the visual inspection prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, an acceptable method to detect the condition of the tank coatings and any loss of material of connecting piping.

[Monitoring and Trending] The Tank and Connected Piping Internal Inspection visually inspects the internal coating of the tanks. The inspection looks for signs of blistering, chipping, peeling, and missing paint as well as signs of corrosion of the underlying carbon steel tank. The inspection also visually inspects connecting piping described in Parameters Monitored or Inspected for signs of loss of material. No actions are taken as part of this activity to trend inspection results. For McGuire, the initial Tank and Connected Piping Internal 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 Unit 1). For Catawba, the initial Tank and Connected Piping Internal 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 Unit 1). The staff finds that the monitoring (visual inspection) frequency of the tanks and associated piping and valves which is prior to the end of the current operating term, and at least once every 10 years during the period of extended operation, is acceptable to ensure that the component intended function is maintained during the period of extended operation.

[Acceptance Criteria] The acceptance criteria for the Tank and Connected Piping Internal Inspection are no visual indications of coating defects that have led to corrosion of the underlying carbon steel tank surfaces, and no unacceptable loss of material of the connecting piping that could result in an unacceptable loss of pressure boundary, as determined by engineering evaluation. Unacceptable loss is defined using a high tolerance in this case, since leakage of the pressure maintenance subsystem of the fire protection system can be tolerated and only serves to make the system less efficient, but does not cause a failure of the system to accomplish its intended function. The staff finds that no visual indications of coating defects that have led to corrosion of the underlying carbon steel tank surfaces, and no unacceptable loss of material of the connecting piping that could result in an unacceptable loss of pressure boundary, as determined by engineering evaluation, are adequate acceptance criteria.

[Operating Experience]  The Tank and Connected Piping Internal Inspection is a new inspection.  Previous visual inspections of the McGuire tank and a similar tank at Catawba have demonstrated that visual inspection of internal surfaces is an effective method for detecting age-related degradation in the tanks and associated piping and valves.  The staff finds the applicant's operating experience provides objective evidence to support the conclusion that the effects of aging will be managed adequately, so that the tank and associated piping intended function will be maintained during the period of extended operation.

FSAR Supplement: The staff has reviewed the USFAR Supplement summary description of the Tank and Connected Piping Internal Inspection in the applicant's response to open item 2.3.3.19-2, and has confirmed that it contains the appropriate elements of the program.

In conclusion, the staff reviewed the applicant's October 28, 2002, response to open item 2.3.3.19-2.  On the basis of this review, as discussed above, the staff finds that there is reasonable assurance that the Tank and Connected Piping Internal 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).

Fire Protection Program — Turbine Building Manual Hose Station Flow Test

In a letter dated November 18, 2002, the applicant provided additional information in response to SER open item 2.3.3.19-4.  In its response, the applicant proposed to address fouling of valves in the turbine building manual hose stations by supplementing the Mechanical Fire Protection Component Tests and Inspections program with the Turbine Building Manual Hose Station Flow Test activity.  This new activity of the Mechanical Fire Protection Component Tests and Inspections program involves the opening of turbine building hose station valves that are within the scope of license renewal at least once every 3 years.  The turbine building valve tests are not governed by SLCs, but will be performed by procedure.  The applicant indicated that this activity is synonymous with the Mechanical Fire Protection Component Tests and Inspections activity already credited for other hose stations within the scope of license renewal.

The staff has reviewed the Mechanical Fire Protection Component Tests and Inspections activity and found that there is reasonable assurance that this activity will adequately manage the aging effects, such that the intended function(s) will be maintained in accordance with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).  Therefore, the staff concludes that the Mechanical Fire Protection Component Tests and Inspections activity is an acceptable program for turbine building manual hose station valves as well.  By augmenting the Mechanical Fire Protection Component Tests and Inspections activity, the staff finds that there is reasonable assurance that this activity will adequately manage the aging effects of the turbine building manual hose stations (particularly fouling of the manual hose rack valves), such that the intended function(s) will be maintained in accordance with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Based on its review of LRA Tables 3.3-26 and 3.3-27, Appendix B, and in correspondence from the applicant , the staff concludes that the above identified AMPs will effectively manage the aging effects of the fire protection system, and that there is reasonable assurance that the intended functions of the fire protection system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.19.3 Conclusions*

The staff reviewed the information in Section 2.3.3.19; Tables 3.3-26 and 3.3-27; Section B.3.12.2 of LRA Appendix B; and information provided by the applicant in letters dated October 28, 2002, and November 18, 2002. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fire protection system will be adequately managed, so that there is reasonable assurance that the system components 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).

## 3.3.20 Fuel Handling Building Ventilation System

*3.3.20.1 Technical Information in the Application*

The fuel handling building ventilation system is essentially the same, and performs the same function, for McGuire and Catawba. The fuel handling building ventilation system maintains ventilation in the spent fuel pool buildings of Units 1 and 2 to permit personnel access. The exhaust portion of the fuel handling building ventilation system controls airborne radioactivity in the fuel pool area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. McGuire UFSAR Section 9.4.2, “Auxiliary Building,” provides additional information concerning the McGuire fuel handling building ventilation system. Catawba UFSAR Section 9.4.2, “Fuel Building Ventilation System,” provides additional information concerning the Catawba fuel handling area ventilation system.

3.3.20.1.1 Aging Effects

Components of the fuel handling building ventilation system are described in Section 2.3.3.20 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-28, pages 3.3-192 through 3.3-193, lists individual components of the system, including air flow monitors, ductwork, filters, tubing, and valve bodies. Exposure of carbon steel, galvanized steel, copper, and brass to a sheltered external environment is subject to loss of material. These same components exposed to ventilation internal environments are not subject to any aging effects. Exposure of internal or external surfaces of stainless steel components to ventilation or sheltered environments has no aging effect.

3.3.20.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the fuel handling building ventilation system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the fuel handling building ventilation system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.20.2 Staff Evaluation*

The applicant described its AMR of the fuel handling building ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.20 and Table 3.3-28, pages 3.3-192 through 3.3-193. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the fuel handling building ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.20.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.20 and Tables 3.3-28, pages 3.3-192 through 3.3-193. The staff notes that RAI 3.3-1, pertaining to aging management of elastomer components associated with ventilation systems, applies to the fuel handling building ventilation system. However, the staff concluded that this RAI was resolved (see Section 3.3.39.3 of this SER).

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function. The applicant identified cracking and shrinkage of structural sealants in the interface between a structural wall, floor, or ceiling and a nonstructural component (such as a duct, piping, electrical cables, doors, and nonstructural walls) resulting from exposure to ambient conditions as potential aging effects.

On the basis of its review, the staff finds that the aging effects that result from contact of the fuel handling building ventilation SSCs to the environments described in LRA Section 2.3.3.20, Table 3.3-28, pages 3.3-192 through 3.3-193, and in correspondence from the applicant, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.20.2.2 Aging Management Programs

LRA Section 2.3.3.20 and Table 3.3-28, pages 3.3-192 through 3.3-193, state that the following aging management programs are credited for managing the aging effects in the fuel handling building ventilation system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-28 and correspondence from the applicant, the staff concludes that the above identified AMPs will effectively manage the aging effects of the fuel handling building ventilation system, and that there is reasonable assurance that the intended functions of the fuel handling ventilation system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.20.3 Conclusions*

The staff reviewed the information in Section 2.3.3.20 and Table 3.3-28 of the LRA. The staff also reviewed correspondence from the applicant. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the fuel handling building ventilation system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.21 Groundwater Drainage System

#### *3.3.21.1 Technical Information in the Application*

The groundwater drainage system is essentially the same, and performs the same function, for McGuire and Catawba. The groundwater drainage system prevents hydrostatic loads on the reactor and auxiliary building substructures. The groundwater drainage system maintains an acceptable groundwater level for the auxiliary building by transferring water out of the auxiliary building, and mitigates the consequences of certain postulated flooding events. McGuire UFSAR Section 9.5.8, "Groundwater Drainage System," provides additional information concerning the McGuire groundwater drainage system. Catawba UFSAR Section 9.5.11, "Groundwater Drainage System," provides additional information concerning the Catawba groundwater drainage system.

##### 3.3.21.1.1 Aging Effects

Components of the groundwater drainage system are described in LRA Section as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-29, pages 3.3-194 to 3.3-196, lists individual components of the system, including pump casings, pipe, orifices, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and yard with no aging effects identified. An internal environment of raw water causes the aging effect of loss of material in stainless steel components. Carbon steel components are subject to the aging effect of loss of material from internal and external surfaces from raw water and sheltered environments. Carbon steel components are identified as embedded in concrete with no external aging effects identified. Cast iron components are subject to the aging effect of loss of material on internal and external surfaces from raw water and sheltered environments.

3.3.21.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the groundwater drainage system:

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (MNP only)
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Sump Pump System Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the groundwater drainage system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.21.2 Staff Evaluation*

The applicant described its AMR of the groundwater drainage system for license renewal in two separate sections of its LRA, Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 3.3-196. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the groundwater drainage system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.21.2.1 Aging Effects

The aging effects that result from contact of the groundwater drainage SSCs to the environments described in LRA Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 through 3.3-196, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.21.2.2 Aging Management Programs

LRA Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 3.3-196, state that the following aging management programs are credited for managing the aging effects in the groundwater drainage system.

- Inspection Program for Civil Engineering Structures and Components
- Selective Leaching Inspection (McGuire only)
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Sump Pump System Inspection

The Fluid Leak Management Program, Galvanic Susceptibility Inspection program, Sump Pump System Inspection program, Inspection Program for Civil Engineering Structures and Components, and Selective Leaching Inspection program (McGuire only) are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-29, the staff concludes that the above identified AMPs will effectively manage the aging effects of the groundwater drainage system, and that there is reasonable assurance that the intended functions of the groundwater drainage system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.21.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.21 and Table 3.3-29, pages 3.3-194 to 3.3-196. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the groundwater drainage system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.22 Hydrogen Bulk Storage System

*3.3.22.1 Technical Information in the Application*

The hydrogen bulk storage system is essentially the same, and performs the same function, for McGuire and Catawba. The hydrogen bulk storage system supplies hydrogen to the volume control tank (CVCS). The hydrogen bulk storage system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2).

3.3.22.1.1 Aging Effects

Components of the hydrogen bulk storage system are described in Section 2.3.3.22 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-30, pages 3.3-197 to 3.3-198, lists individual components of the system, including pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal environment of gas, and external environments of sheltered and yard with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified. Brass components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of brass components exposed to gas are not subject to any aging effects. Copper components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of copper components exposed to gas are not subject to any aging effects.

3.3.22.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the hydrogen bulk storage system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the hydrogen bulk storage system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.22.2 Staff Evaluation*

The applicant described its AMR of the hydrogen bulk storage system for license renewal in two separate sections of its LRA, Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 3.3-198. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the hydrogen bulk storage system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.22.2.1 Aging Effects

The aging effects that result from contact of the hydrogen bulk storage SSCs to the environments described in LRA Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 through 3.3-198, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.22.2.2 Aging Management Programs

LRA Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 198, state that the following aging management programs are credited for managing the aging effects in the hydrogen bulk storage system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program, and the Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-30, the staff concludes that the above identified AMPs will effectively manage the aging effects of the hydrogen bulk storage system, and that there is reasonable assurance that the intended functions of the hydrogen bulk storage system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.22.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.22 and Table 3.3-30, pages 3.3-197 to 3.3-198. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the hydrogen bulk storage system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.23 Instrument Air System

*3.3.23.1 Technical Information in the Application*

The McGuire instrument air system provides dry, oil-free air for instrumentation, testing, and control air requirements. McGuire UFSAR Section 9.3.1, "Compressed Air Systems," provides additional information concerning the McGuire instrument air system.

The Catawba instrument air system supplies clean, oil-free, dried, compressed air to all air-operated instrumentation and valves for both units. Catawba UFSAR Section 9.3.1, "Compressed Air System," provides additional information concerning the Catawba instrument air system.

3.3.23.1.1 Aging Effects

Components of the instrument air system are described in Section 2.3.3.23 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-31, pages 3.3-199 to 3.3-201, lists individual components of the system, including filters, accumulators, tanks, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to an internal environment of air, and an external environment that is sheltered or in the reactor building, with no aging effects identified. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of air with no aging effects identified. Galvanized steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Galvanized steel components are identified as being subject to the internal environment of air with no aging effects identified. Brass components are subject to the aging effect of loss of material on external surfaces from exposure to sheltered environments. Internal surfaces of brass components exposed to air are not subject to any aging effects. Copper components are subject to the aging effect of loss of material from external surfaces from exposure to sheltered environments. Internal surfaces of copper components exposed to air are not subject to any aging effects.

3.3.23.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the instrument air system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the instrument air system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.23.2 Staff Evaluation*

The applicant described its AMR of the instrument air system for license renewal in two separate sections of its LRA, Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 3.3-201. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the instrument air system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.23.2.1 Aging Effects

The aging effects that result from contact of the instrument air SSCs to the environments described in LRA Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 through 3.3-201, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.23.2.2 Aging Management Programs

LRA Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 3.3-201, state that the following aging management programs are credited for managing the aging effects in the instrument air system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program, and the Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-31, the staff concludes that the above identified AMPs will effectively manage the aging effects of the instrument air system, and that there is reasonable assurance that the intended functions of the instrument air system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.23.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.23 and Table 3.3-31, pages 3.3-199 to 3.3-201. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the instrument air system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.24 Liquid Waste System

*3.3.24.1 Technical Information in the Application*

The McGuire liquid waste recycle and liquid waste monitor and disposal systems collect, segregate, and process the reactor-grade and non-reactor-grade liquid wastes produced during station operation, refueling, or maintenance. Portions of the liquid waste recycle system function as part of the RCS leakage detection systems. McGuire UFSAR Section 11.2, “Liquid Waste System,” provides additional information concerning the McGuire liquid waste recycle and liquid waste monitor and disposal systems.

The Catawba liquid radwaste system collects, segregates, and processes all radioactive and potentially radioactive liquids generated in the plant. In general, all reactor-grade liquids are recycled and all non-reactor-grade liquids are processed and disposed of in accordance with applicable NRC regulations. The system is designed to control and minimize releases of radioactivity to the environment. Catawba UFSAR Section 11.2, “Liquid Radwaste System,” provides additional information concerning the Catawba liquid radwaste system.

3.3.24.1.1 Aging Effects

Components of the liquid waste system are described in Section 2.3.3.24 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-32, pages 3.3-202 to 3.3-208, lists individual components of the system, including tanks, pumps, pipe, orifices, separators, strainers, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal environment of raw water, borated water, and treated water causes the aging effect of loss of material in stainless steel components. Cracking in stainless steel is also caused by exposure of internal surfaces to borated water and treated water. Internal surfaces of stainless steel components are also subject to the aging effects of cracking (wet/dry) and loss of material (wet/dry) from exposure to a treated water environment. Internal surfaces of stainless steel components exposed to ventilation or gas environments are not subject to any aging effects. Carbon steel components are subject to the aging effect of loss of material from internal environments of raw water and treated water, and external surfaces to the environments of reactor building and sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified.

3.3.24.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the liquid waste recycle and liquid waste monitor and disposal systems:

- Inspection Program for Civil Engineering Structures and Components
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Liquid Waste Inspection
- Chemistry Control Program
- Flow-Accelerated Corrosion Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the liquid waste recycle and liquid waste monitor and disposal systems will be adequately managed by these aging management programs during the period of extended operation.

*3.3.24.2 Staff Evaluation*

The applicant described its AMR of the liquid waste systems for license renewal in two separate sections of its LRA, Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 3.3-208. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the liquid waste systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.24.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 3.3-208. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.32-1, additional information pertaining to Table 3.3-32, "Aging Management Review Results — Liquid Waste System." This table indicates that stainless steel piping and loop seals at the McGuire plant have the aging effect of loss of material and cracking due to exposure to wet/dry conditions. The applicant was requested to identify where in the LRA the AMR for the wet/dry aging effect is, and explain how the effect is managed by the Chemistry Control Program, or to provide a justification for excluding this environment/aging effect from LRA Table 3.3-32.

In its response dated March 15, 2002, the applicant stated that the aging management review results for the liquid waste systems are presented in Table 3.3-32 of the LRA. The components exposed to an alternate wet and dry environment are piping and valves associated with the loop seal shown on drawing MCFD-1565-03.00 at coordinate D-4, and drawing MCFD-2565-03.00 at coordinates L-3. The seal is established by the addition of demineralized water from the demineralized water system to the loop. Loss of material and cracking could occur as a result of the concentration of contaminants from alternate wetting and drying. Demineralized water contains minimal, if any, contaminants and is monitored and controlled by the Chemistry Control Program. Monitoring and controlling the quality of demineralized water used in plant systems, such as the liquid waste system loop seal, will minimize contaminant levels, such that concentrations that could pose a concern can not be achieved through alternate wetting and drying. Therefore, the Chemistry Control Program will mitigate loss of material and cracking of the loop seal components exposed to alternate wetting and drying from demineralized water by monitoring and maintaining the water quality of the demineralized water system. Since the applicant reviewed the aging effect and credits the Chemistry Control Program to manage it, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.32-2, additional information pertaining to LRA Table 3.3-32, “Aging Management Review Results — Liquid Waste System.” This table identifies the aging effect of loss of material and cracking of stainless steel due to exposure to wet/dry conditions. The applicant was requested to clarify if this aging effect is also applicable to the sump pump components identified in LRA Table 3.3-32.

In its response dated March 15, 2002, the applicant stated that Table 3.3-32 of the LRA identified loss of material and cracking of stainless steel pipe and valves at McGuire due to exposure to alternate wet/dry conditions in a treated water environment. Loss of material and cracking of stainless steel due to exposure to wet/dry conditions does not apply to the sump pump components identified in LRA Table 3.3-32. The sump pump components are exposed to a raw water environment only. Since the applicant clarified that the sump pump components are exposed to a raw water environment only, the staff finds its response acceptable.

The staff finds that the applicant's responses clarify and satisfactorily resolve these items. The aging effects that result from contact of the liquid waste SSCs to the environments described in LRA Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 through 3.3-208, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.24.2.2 Aging Management Programs

LRA Section 2.3.3.24 and Table 3.3-32, pages 3.3-202 to 3.3-208, state that the following aging management programs are credited for managing the aging effects in the liquid waste systems.

- Inspection Program for Civil Engineering Structures and Components
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Liquid Waste Inspection
- Chemistry Control Program
- Flow-Accelerated Corrosion Program

The Fluid Leak Management Program, Galvanic Susceptibility Inspection Program, Chemistry Control Program, Inspection Program for Civil Engineering Structures and Components, Flow-Accelerated Corrosion Program, and Liquid Waste System Inspection program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-32, the staff concludes that the above identified AMPs will effectively manage the aging effects of the liquid waste systems, and that there is reasonable assurance that the intended functions of the liquid waste systems will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.24.3 Conclusions*

The staff reviewed the information in Section 2.3.3.24 and Table 3.3-32 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the liquid waste systems will be adequately managed, so that there is reasonable assurance that the system components 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).

**3.3.25 Miscellaneous Structures Ventilation System**

*3.3.25.1 Technical Information in the Application*

The turbine building ventilation system at McGuire performs the corresponding functions as the miscellaneous structures ventilation system at Catawba.

The Catawba miscellaneous structures ventilation system includes the standby shutdown facility (SSF) HVAC. The SSF HVAC portion of the miscellaneous structures ventilation system provides the environmental controls necessary to ensure that SSF equipment is maintained operable during postulated fires and station blackout.

Components of the miscellaneous structures ventilation system are described in Section 2.3.3.25 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-33, page 3.3-209, of the LRA lists individual components of the system, including air handling units, ductwork, flexible connectors, and plenum sections. Galvanized steel components exposed to an internal environment of ventilation and sheltered environments are not subject to any aging effects. Neoprene components exposed to ventilation and sheltered environments are not subject to any aging effects.

No AMPs are required to manage aging effects for the miscellaneous structures ventilation system.

*3.3.25.2 Staff Evaluation*

The applicant described its AMR of the miscellaneous structures ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.25 and Table 3.3-33, page 3.3-209. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the miscellaneous structures ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.25.2.1 Aging Effects

The applicant’s conclusion that no aging effects result from contact of the miscellaneous structures ventilation SSCs to the environments listed in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, of the LRA is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments identified.

3.3.25.2.2 Aging Management Programs

There are no aging effects identified in this system. Therefore, no AMPs are required in the miscellaneous structures ventilation system.

*3.3.25.3 Conclusions*

The staff reviewed the information in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, of the LRA. On the basis of its review, the staff concludes that the SCs in the miscellaneous structures ventilation system are not subject to any aging effects. Therefore, no AMPs are required in the miscellaneous structures ventilation system.

### 3.3.26 Nitrogen System

*3.3.26.1 Technical Information in the Application*

The McGuire nitrogen system provides a safety-related supply of nitrogen to the pneumatic actuators on the feedwater isolation valves.

The Catawba nitrogen system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of these systems are within the scope of license renewal per 10 CFR 54.4(a)(2).

Components of the nitrogen system are described in Section 2.3.3.26 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-34, page 3.3-210, of the LRA lists individual components of the system, including tanks, pipe, tubing, and valve bodies. Stainless steel components exposed to a gas internal environment and a sheltered external environment are not subject to any aging effects.

3.3.26.1.2 Aging Management Programs

No AMPs are required to manage aging effects for the nitrogen system.

*3.3.26.2 Staff Evaluation*

The applicant described its AMR of the nitrogen system for license renewal in two separate sections of its LRA, Section 2.3.3.26 and Table 3.3-34, page 3.3-210. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the nitrogen system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.26.2.1 Aging Effects

The staff reviewed the applicant’s response to RAI 2.3.3.26-2, which provided AMR results for additional components (valve bodies and tubing associated with the safety-related SG PORV back-up control system) that were identified by the applicant as within the scope of license renewal (documented in Section 2.3.3.26.2 of this SER). The applicant’s conclusion that no aging effects result from contact of the nitrogen SSCs to the environments listed in the RAI response and in LRA Section 2.3.3.26 and Table 3.3-34, on page 3.3-210, is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments identified.

3.3.26.2.2 Aging Management Programs

There are no aging effects identified for this system. Therefore, no AMPs are required in the nitrogen system.

*3.3.26.3 Conclusions*

The staff reviewed the information in the applicant’s response to RAI 2.3.3.26-2 and LRA Section 2.3.3.26 and Table 3.3-34, page 3.3-210. On the basis of its review, the staff concludes that the SCs in the nitrogen system are not subject to any aging effects. Therefore, no AMPs are required for the nitrogen system.

### 3.3.27 Nuclear Sampling System

*3.3.27.1 Technical Information in the Application*

The nuclear sampling system is essentially the same, and performs the same function, for McGuire and Catawba. The nuclear sampling system provides a means of obtaining samples, taken more frequently during normal plant operation, from the station's safety-related systems in a convenient, shielded, and safe environment. The system also provides a means of sampling the reactor coolant and containment atmosphere following a LOCA to monitor the reactor and determine the degree of core damage. McGuire UFSAR Section 9.3.2, “Nuclear Sampling System,” provides additional information concerning the McGuire nuclear sampling system. Catawba UFSAR Section 9.3.2, “Process Sampling and Post-Accident Sampling Systems,” provides additional information concerning the Catawba Nuclear Sampling System.

Components of the nuclear sampling system are described in Section 2.3.3.27 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-35, pages 3.3-211 to 3.3-213, lists individual components of the system, including orifices, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal environment of borated water and treated water causes the aging effect of loss of material and cracking in stainless steel components. Internal surfaces of stainless steel components exposed to gas environments are not subject to any aging effects.

The Chemistry Control Program is utilized to manage aging effects for the nuclear sampling system. 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's review of this common aging management program is documented in Section 3.0 of the SER.

A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the nuclear sampling system will be adequately managed by the aging management program during the period of extended operation.

*3.3.27.2 Staff Evaluation*

The applicant described its AMR of the nuclear sampling system for license renewal in two separate sections of its LRA, Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 3.3-213. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the nuclear sampling system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.27.2.1 Aging Effects

The aging effects that result from contact of the nuclear sampling SSCs to the environments described in LRA Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 through 3.3-213, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.27.2.2 Aging Management Programs

LRA Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 3.3-213, state that the Chemistry Control Program is credited for managing the aging effects in the nuclear sampling system. 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-35, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear sampling system, and that there is reasonable assurance that the intended functions of the nuclear sampling system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.27.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.27 and Table 3.3-35, pages 3.3-211 to 3.3-213. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear sampling system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.28 Nuclear Service Water System

*3.3.28.1 Technical Information in the Application*

The McGuire nuclear service water system provides cooling water from Lake Norman, or the standby nuclear service water pond, to various safety-related and non-safety-related heat exchangers. In addition, the system acts as an assured source of makeup water for various requirements, and is the normal supply of water for the containment ventilation cooling water system. McGuire UFSAR Section 9.2.2, “Nuclear Service Water System and Ultimate Heat Sink,” provides additional information concerning the McGuire nuclear service water system.

The Catawba nuclear service water system, along with Lake Wylie and the standby nuclear service water pond, provides the ultimate heat sink for various safety-related heat loads during normal operation and design basis events. The nuclear service water system also supplies emergency makeup water to various safety-related systems during postulated design basis events, water for fire protection hose stations in the diesel buildings and nuclear service water pumphouse, and cooling flow and flush water for non-QA heat loads and functions during normal operation. Catawba UFSAR Section 9.2.1, “Nuclear Service Water System,” provides additional information concerning the Catawba nuclear service water system.

3.3.28.1.1 Aging Effects

Components of the nuclear service water system are described in Section 2.3.3.28 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-36, pages 3.3-214 to 3.3-221 (McGuire Nuclear Station), and LRA Table 3.3-37, pages 3.3-222 to 3.3-228 (Catawba Nuclear Station), list individual components of the system, including oil coolers, expansion joints, pump casings, strainers, orifices, pipe, tubing, annubars, flexible hoses, manways, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered, reactor building, yard, and oil with no aging effects identified. Stainless steel components identified as being subject to the external environment of underground are subject to the aging effect of loss of material and cracking. An internal environment of raw water causes the aging effect of loss of material in stainless steel components. Internal surfaces of stainless steel components exposed to oil environments are not subject to any aging effects.

Internal or external surfaces of carbon steel components exposed to raw water, reactor building, underground, yard, or sheltered environments are subject to the aging effect of loss of material. Copper-nickel components exposed to an internal environment of raw water are subject to fouling and/or loss of material. Exposure of copper-nickel components to an external oil environment has no aging effect. Brass components exposed to an internal environment of raw water are subject to loss of material. Exposure of brass components to an external environment of oil has no aging effect. Cast iron components exposed to internal or external environments of raw water or sheltered are subject to loss of material.

3.3.28.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the nuclear service water system:

- Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers
- Service Water Piping Corrosion
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities — Condenser Circulation Water System Internal Coating Inspection
- Selective Leaching Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the nuclear service water system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.28.2 Staff Evaluation*

The applicant described its AMR of the nuclear service water system for license renewal in two separate sections of its LRA, Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 3.3-221, and Table 3.3-37, pages 3.3-222 to 3.3-228. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the nuclear service water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.28.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 3.3-221, and Table 3.3-37, pages 3.3-222 to 3.3-228. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI-3.3.36-1, additional information pertaining to LRA Table 3.3-36, "Aging Management Review Results — Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that centrifugal and reciprocating charging pumps and safety injection pump oil coolers (tubes and tubesheets) have a raw water internal/external environment with an oil internal/external environment. No aging effect is identified for these environments. Oil systems subject to water contamination are typically subject to the aging effect of loss of material. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to stainless steel and copper-nickel materials for oil coolers potentially contaminated with leaking water, or to provide a justification for excluding this aging effect from LRA Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that all of the lube oil cooler components cited in RAI 3.3.36-1 are components of closed oil recirculation systems. Uncontaminated lube oil does not cause aging, and closed oil recirculation systems are assumed to be initially free of contaminants, such as water. Further, in the Duke aging management review, component failures were not postulated as a means to establish the relevant conditions required for aging to occur. Therefore, in oil coolers, tube failures that could introduce water into a lube oil environment are not assumed.

By electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff commented on the applicant's response, indicating that all systems are designed initially to be leak tight, but failures in a heat exchanger system during the lifetime of the system cannot be ruled out. In fact, industry operating experience indicates that oil periodically is contaminated with cooling water. Furthermore, leakage of water into oil systems may not involve component failures per se, but could involve minor breaches in component pressure boundaries that may go undetected and allow corrosion and other forms of degradation to progress indefinitely (which is why plants implement surveillance monitoring programs for oil lubricating and fuel oil systems). The staff further noted that the GALL report also addresses this aging effect for oil environments.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant responded that Duke is assuming that the staff believes breaches of the pressure boundary in the oil coolers are the result of aging of the raw water side of the cooler that allows raw water to contaminate the oil. Duke reiterates that component failures due to aging were not postulated as a means to establish the relevant conditions required for aging to occur. For the oil coolers in question, Duke identified the aging that could occur in the normal environment. No aging effects were identified for the cooler components exposed to uncontaminated oil.

The applicant further stated that aging effects were identified for the cooler components exposed to raw water that, left unmanaged, could result in a loss of the pressure boundary function. Duke credited the Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers described in Section B.3.17.7 of LRA Appendix B to maintain the pressure boundary integrity to prevent the contamination of the oil system. Industry operating experience indicates the need for such a monitoring program. Plant-specific operating experience also demonstrates that the aging management program credited has been, and will continue to be, effective during the period of extended operation. By letter from the applicant dated July 9, 2002, the staff received this information in official correspondence. The applicant was able to demonstrate that aging effects of the cooler components exposed to raw water will be adequately managed to maintain the pressure boundary integrity to prevent the contamination of the oil system. The staff agrees that uncontaminated oil will not cause any aging effect to the components, and that the applicant is not required to assume a failure that can cause an aging effect. Therefore, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-2, additional information pertaining to LRA Table 3.3-36, "Aging Management Review Results — Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that the copper-nickel centrifugal and reciprocating charging pump, the safety injection pump bearing oil cooler, and the centrifugal charging pump speed reducer oil cooler tubes are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of selective leaching for copper-nickel components in a raw water environment, or to provide a justification for excluding this aging effect from LRA Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that the relevant conditions required for loss of material, due to selective leaching, to occur in copper-nickel alloys are a temperature greater than 212 °F, low flow, and high local heat fluxes. These conditions are not found in the nuclear service water system. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for copper-nickel alloy components exposed to raw water.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff commented on the applicant's response, stating that service water inspections and industry experience from ANO-1 indicate that, even under high flow conditions, the impurity, chlorine biocide, in the systems resulted in de-nickelification to the 90/10 copper-nickel heat exchanger tube,s where 70/30 copper-nickel may have been less susceptible to the selective leaching aging effect. The staff further noted that the copper content of the component is a significant contributor to material vulnerability, independent of temperature and flow conditions.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant replied that Duke believes that the industry experience from ANO-1 is not relevant to the McGuire nuclear service water system. The McGuire nuclear service water system is an untreated open-cycle cooling water system. The operating experience presented notes that selective leaching occurred as a result of the chlorine biocide. Duke does not use chlorine biocides in the McGuire nuclear service water system. Therefore, selective leaching of copper-nickel alloys is not a concern. By letter from the applicant dated July 9, 2002, the staff received this information in official correspondence. Since the applicant demonstrated that McGuire operating practices precluded selective leaching as a result of chlorine biocide, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-3, additional information pertaining to LRA Table 3.3-36, "Aging Management Review Results — Nuclear Service Water System (McGuire Nuclear Station)." This table indicates that the copper-nickel reciprocating charging pump bearing oil cooler and the fluid drive oil cooler tubes are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the aging effect of fouling for the copper-nickel tubes in a raw water environment was identified, or to provide a justification for excluding this aging effect from LRA Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that the reciprocating charging pumps are not relied upon for any event at the McGuire Nuclear Station. The nuclear service water side of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is only in scope because it is associated with Class F piping and, therefore, meets the criteria of 10 CFR 54.4(a)(2). Loss of pressure boundary integrity could prevent satisfactory accomplishment of a safety function. Only the pressure boundary integrity of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler is required to be maintained; heat transfer is not an intended function of the tubes that meets the scoping criteria in 10 CFR 54.4. Fouling can cause a loss of heat transfer function, but does not affect the pressure boundary function of the reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes. Therefore, fouling is not an aging effect requiring management during the period of extended operation. The staff finds this a logical explanation of why fouling is not identified as an aging effect for the copper-nickel tubes. The staff agrees with the applicant that fouling is not an applicable aging effect requiring management since heat transfer is not an intended function of the tubes that meets the scoping criteria in 10 CFR 54.4.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.36-4, additional information pertaining to LRA Table 3.3-36, “Aging Management Review Results — Nuclear Service Water System (McGuire Nuclear Station).” This table indicates that the cast iron reciprocating charging pump fluid drive oil cooler channel covers are subject to an internal environment of raw water. The applicant was requested to identify where in the LRA the aging effect of selective leaching for cast iron components in a raw water environment was identified, or to provide a justification for excluding this aging effect from LRA Table 3.3-36 and an AMR.

In its response dated March 15, 2002, the applicant stated that loss of material due to selective leaching is an aging effect applicable only to “gray” cast iron. The reciprocating charging pump fluid drive oil cooler channel covers are constructed of “long black iron,” which is carbon steel. Therefore, loss of material due to selective leaching is not an aging effect requiring management during the period of extended operation for the channel covers in Table 3.3-36 of the LRA. The LRA Table 3.3-36 entry for the “Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)” is in error. The Table 3.3-36 entry for the “Reciprocating Charging Pump Fluid Drive Oil Coolers (channel covers)” was revised to reflect the correct material for these channel covers, which is carbon steel. Since the applicant clarified that the component material is carbon steel, the staff agrees that loss of material due to selective leaching is not an applicable aging effect.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.37-1, additional information pertaining to LRA Table 3.3-37, “Aging Management Review Results — Nuclear Service Water System (Catawba Nuclear Station).” On pages 3.3-222 through 3.3-228 of the LRA, the applicant indicated that loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90/10 copper-nickel, ductile cast iron, and stainless steel materials in a raw water environment. Pitting corrosion can be inhibited by maintaining an adequate flow rate, which prevents impurities from adhering to the material surface. The more susceptible locations for pitting corrosion to occur in materials in a raw water environment are locations of low or stagnant flow. The applicant was requested to identify where in the LRA the AMR results are for the aging effect of pitting corrosion in low flow or stagnant conditions, or to provide a justification for excluding this aging effect from LRA Table 3.3-37 and an AMR.

In its response dated March 15, 2002, the applicant stated that in the Duke aging management review, pitting corrosion is considered an aging mechanism that manifests itself as loss of material. Loss of material is the aging effect requiring management for license renewal. Loss of material is identified in LRA Table 3.3-36 for all applicable materials exposed to raw water, and is managed by the Service Water Piping Corrosion Program. The staff verified that the Service Water Piping Corrosion Program will manage loss of material. However, the applicant should justify how its program will manage the effects of localized corrosion, caused by pitting and MIC to ensure that the intended pressure boundary function is provided during all design basis events consistent with the CLB throughout the extended period of operation, as required by 10 CFR 54.21(a)(3). This issue is characterized as open item 3.0.3.15.2-1 and is discussed in detail in Section 3.0.3.15.2 of this SER.

The staff finds that the applicant's responses to RAI 3.3.36-3, 3.3.36-4, and 3.3.37-1 clarify and satisfactorily resolve these items. The aging effects that result from contact of the nuclear service water SSCs to environments as described in LRA Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 3.3-221, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.28.2.2 Aging Management Programs

LRA Section 2.3.3.28 and Table 3.3-36, pages 3.3-214 to 3.3-221, state that the following aging management programs are credited for managing the aging effects in the nuclear service water system.

- Heat Exchanger Preventive Maintenance Activities — Pump Oil Coolers
- Service Water Piping Corrosion
- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Preventive Maintenance Activities — Condenser Circulation Water System Internal Coating Inspection
- Selective Leaching Inspection

The Fluid Leak Management Program, Galvanic Susceptibility Inspection program, Service Water Piping Corrosion Program, Inspection Program for Civil Engineering Structures and Components, Preventive Maintenance Activities — Condenser Circulation Water System Internal Coating Inspection program, and Selective Leaching Inspection program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-37, the staff concludes that the above identified AMPs will effectively manage the aging effects of the nuclear service water system, and that there is reasonable assurance that the intended functions of the nuclear service water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.28.3 Conclusions*

The staff reviewed the information in Section 2.3.3.28 and Table 3.3-37 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear service water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.29 Nuclear Service Water Pump Structure Ventilation System (Catawba Only)

*3.3.29.1 Technical Information in the Application*

No system corresponding to the Catawba nuclear service water pump structure ventilation system exists at McGuire. McGuire has no nuclear service water pump structure.

The Catawba nuclear service water pump structure ventilation system creates and maintains a suitable environmental temperature for the operation of equipment located in the nuclear service water pump structure. Catawba UFSAR Section 9.4.8, "Nuclear Service Water Pump Structure Ventilation System," provides additional information concerning the Catawba nuclear service water pump structure ventilation system.

3.3.29.1.1 Aging Effects

Components of the nuclear service water pump structure ventilation system are described in Section 2.3.3.29 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-38, pages 3.3-229 to 3.3-230, lists individual components of the system, including ductwork, pipe, tubing, and valve bodies. Galvanized steel, brass, copper, or stainless steel components exposed to ventilation and sheltered environments are not subject to any aging effects. Carbon steel components exposed to sheltered environments demonstrate loss of material. Exposure of carbon steel to an internal environment of ventilation has no aging effect.

3.3.29.1.2 Aging Management Programs

The Inspection Program for Civil Engineering Structures and Components is utilized to manage aging effects for the nuclear service water pump structure ventilation system. A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the nuclear service water pump structure ventilation system will be adequately managed by the aging management program during the period of extended operation.

*3.3.29.2 Staff Evaluation*

The applicant described its AMR of the nuclear service water pump structure ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 to 3.3-230. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the nuclear service water pump structure ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.29.2.1 Aging Effects

The aging effects that result from contact of the nuclear service water pump structure ventilation SSCs to the environments described in LRA Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 through 3.3-230, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.29.2.2 Aging Management Programs

LRA Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 to 3.3-230, state that the Inspection Program for Civil Engineering Structures and Components is credited for managing the aging effects in the nuclear service water pump structure ventilation system. The Inspection Program for Civil Engineering Structures and Components 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-38, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear service water pump structure ventilation system, and that there is reasonable assurance that the intended functions of the nuclear service water pump structure ventilation system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.29.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.29 and Table 3.3-38, pages 3.3-229 to 3.3-230. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear service water pump structure ventilation system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.30 Nuclear Solid Waste Disposal System

*3.3.30.1 Technical Information in the Application*

The McGuire nuclear solid waste disposal system is relied upon to contain solid radioactive waste materials as they are produced in the station. McGuire UFSAR Section 11.5, "Nuclear Solid Waste Disposal System," provides additional information concerning the McGuire nuclear solid waste disposal system.

The Catawba solid radwaste system provides capacity to contain and store radioactive waste materials as they are produced in the station, and prepares the waste for eventual shipment to a licensed offsite disposal facility. The solid radwaste system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2).

3.3.30.1.1 Aging Effects

Components of the nuclear solid waste disposal system are described in Section 2.3.3.30 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-39, pages 3.3-231 to 3.3-233, lists individual components of the system, including screens, resin storage tanks, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and gas with no aging effects identified. Internal or external environments of treated water cause the aging effects of loss of material and cracking in stainless steel components. Internal surfaces of stainless steel components exposed to gas environments are not subject to any aging effects.

3.3.30.1.2 Aging Management Programs

The Treated Water Systems Stainless Steel Inspection is utilized to manage aging effects for the nuclear solid waste disposal system. A description of the aging management program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the solid waste disposal system will be adequately managed by the aging management program during the period of extended operation.

*3.3.30.2 Staff Evaluation*

The applicant described its AMR of the nuclear solid waste disposal system for license renewal in two separate sections of its LRA, Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 3.3-233. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the nuclear solid waste disposal system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.30.2.1 Aging Effects

The aging effects that result from contact of the nuclear solid waste disposal SSCs to the environments described in LRA Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 through 3.3-233, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.30.2.2 Aging Management Programs

LRA Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 3.3-233, state that the Treated Water Systems Stainless Steel Inspection is credited for managing the aging effects in the nuclear solid waste disposal system. The Treated Water Systems Stainless Steel Inspection 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 documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-39, the staff concludes that the above identified AMP will effectively manage the aging effects of the nuclear solid waste disposal system, and that there is reasonable assurance that the intended functions of the nuclear solid waste disposal system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.30.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.30 and Table 3.3-39, pages 3.3-231 to 3.3-233.  On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the nuclear solid waste disposal system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.31 Reactor Coolant Pump Motor Oil Collection Subsystem

*3.3.31.1 Technical Information in the Application*

Each reactor coolant pump motor at McGuire and Catawba is equipped with an oil collection system that contains any oil leakage.

3.3.31.1.1 Aging Effects

Components of the reactor coolant pump motor oil collection subsystem are described in Section 2.3.3.31 of the LRA as being within the scope of license renewal, and subject to an AMR.  LRA Table 3.3-40, pages 3.3-234 to 3.3-238, lists individual components of the system, including flexible hoses, level gauges, drain tanks, pump casings, oil catchers, oil pots, oil lift enclosures, pipe, and valve bodies.  Exposure of internal and external surfaces of stainless steel to ventilation, reactor building, and sheltered environments has no aging effect.  Exposure of carbon steel to reactor building and sheltered external environments results in loss of material.  Exposure of internal surfaces of carbon steel components to ventilation environments has no aging effect.  Cast iron components exposed to external reactor building environment demonstrate loss of material.  Cast iron exposed to a ventilation environment has no aging effect.  Glass components exposed to ventilation and reactor building environments are not subject to any aging effects.

3.3.31.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the reactor coolant pump motor oil collection subsystem:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

A description of these aging management programs is provided in Appendix B of the LRA.  The applicant concludes that the effects of aging associated with the components of the reactor coolant pump motor oil collection subsystem will be adequately managed by these aging management programs during the period of extended operation.

### *3.3.31.2 Staff Evaluation*

The applicant described its AMR of the reactor coolant pump motor oil collection subsystem for license renewal in two separate sections of its LRA, Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 3.3-238. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the reactor coolant pump motor oil collection subsystem will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.3.31.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 3.3-238. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.40-1, additional information pertaining to LRA Table 3.3-40, “Aging Management Review Results — Reactor Coolant Pump Motor Oil Collection Subsystem.” This table indicates that flexible hoses are of the material type of stainless steel. Per CN-1553-1.3 and CN-2553.1-3, “Flow Diagram of Reactor Coolant System (NC),” line listings for the flexible hoses between the upper bearing oil enclosures and the reactor coolant pump motor drain tank are carbon steel. The applicant was requested to identify where in the LRA the AMR results are for the reactor coolant pump motor oil collection subsystem carbon steel flexible hoses, or to provide a justification for excluding these components from LRA Table 3.3-40 and an AMR.

In its response dated March 15, 2002, the applicant stated that in general, the materials identified in the line listings on Duke flow diagrams refer to pipe and pipe components and would be generally used for other system components. Materials for some engineered components may be different than the general system material, as is the case here. All of the flexible hoses shown on flow diagrams CN-1553-1.3 and CN-2553-1.3 are stainless steel. No carbon steel flexible hoses are installed within the license renewal evaluation boundaries of the reactor coolant pump motor oil collection subsystem. Since the applicant clarified that the components are made of stainless steel, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.40-2, additional information pertaining to LRA Table 3.3-40, “Aging Management Review Results — Reactor Coolant Pump Motor Oil Collection Subsystem.” This table indicates that all components are subject to an internal environment of ventilation, and an external environment of reactor building or ventilation. The applicant was requested to explain why these components of the reactor coolant pump motor oil collection subsystem are not subject to an internal and/or external environment of oil.

In its response dated March 15, 2002, the applicant stated that, in accordance with plant directives and procedures, the reactor coolant pump motor oil collection subsystem is not allowed to be used as an oil storage system. Any used oil that has collected in the drain tank during operation is drained from the system during each refueling outage, and the system is flushed before returning to service following the outage. Therefore, the internal environment of the system at the beginning of each operating cycle is air that enters the system from the reactor building environment during the fill, drain, and flush operations, and oil leakage is not expected as a normal operating condition. Since the collected oil will be drained from the system during each outage, and the system is flushed before it is returned to service, the staff agrees that the applicant is not required to assume contamination of the internal environment with oil leakage.

The staff finds that the applicant's responses clarify and satisfactorily resolve these items. The aging effects that result from contact of the reactor coolant pump motor oil collection subsystem SSCs to the environments described in LRA Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 through 3.3-238, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.31.2.2 Aging Management Programs

LRA Section 2.3.3.31 and Table 3.3-40, pages 3.3-234 to 3.3-238, state that the following aging management programs are credited for managing the aging effects in the reactor coolant pump motor oil collection subsystem.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-40, the staff concludes that the above identified AMPs will effectively manage the aging effects of the reactor coolant pump motor oil collection subsystem, and that there is reasonable assurance that the intended functions of the reactor coolant pump motor oil collection subsystem will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.31.3 Conclusions*

The staff reviewed the information in Section 2.3.3.31 and Table 3.3-40 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor coolant pump motor oil collection subsystem will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.32 Reactor Coolant System (Non-Class 1 Components)

#### *3.3.32.1 Technical Information in the Application*

The non-class 1 portions of the RCS (excluding the RCP motor oil collection subsystem) are essentially the same, and perform the same function, for McGuire and Catawba. The non-class 1 portions of the RCS are relied upon to provide and maintain containment isolation and closure, and to maintain system pressure boundary integrity. The reactor vessel leak-off line is included within this set of components, and is relied upon only in the event the reactor vessel flange inner seal leaks.

##### 3.3.32.1.1 Aging Effects

Components of the RCS (non-Class 1 components) are described in Section 2.3.3.32 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-41, pages 3.3-239 to 3.3-241, lists individual components of the system, including orifices, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the internal or external environments of reactor building, sheltered, and gas with no aging effects identified. Stainless steel components exposed to borated water environments demonstrate loss of material and cracking. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to sheltered environments. Carbon steel components are identified as being subject to the internal environment of gas with no aging effects identified.

##### 3.3.32.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the RCS (non-Class 1 components):

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the RCS (non-Class 1 components) will be adequately managed by these aging management programs during the period of extended operation.

#### *3.3.32.2 Staff Evaluation*

The applicant described its AMR of the RCS (non-Class 1 components) for license renewal in two separate sections of its LRA, Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 3.3-241. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the RCS (non-Class 1 components) will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.32.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 3.3-241. During its review, the staff determined that additional information was needed to complete its review. By letter dated in January 23, 2002, the staff requested, in RAI 3.3.41-1, additional information pertaining to LRA Table 3.3-41, "Aging Management Review Results — Reactor Coolant System (non-Class 1 Components)." This table refers to Note (3), which states that orifices may be subjected to a borated water or steam environment. The applicant was requested to identify where in the LRA the AMR results are for the RCS orifices in a borated water or steam environment, or to provide a justification for excluding these environments from LRA Table 3.3-41 and an AMR.

In its response dated March 15, 2002, the applicant stated that the orifice listed in Table 3.3-41 of the LRA is located in the common reactor vessel high-point vent line, downstream from the parallel, redundant vent line isolation valve sets, which are isolated during normal plant operation. These orifices are depicted on drawings MCFD 1553-2.01 (at K-6), MCFD-2553-2.01 (at K-6), CN-1553-1.1 (at K-7), and CN-2553-1.1 (at K-7). The vent line is normally used only during system fill operations to vent gasses from the RCS to the pressurizer relief tank, or during an accident to ensure that voiding does not occur in the reactor vessel head. The orifice and downstream piping between the orifice and the pressurizer relief tank are open to the pressurizer relief tank environment. As a result, the orifice is exposed to the gas environment normal to the pressurizer relief tank. Therefore, the aging management review was performed for a "gas" environment. Note (3) should not have been included at the end of LRA Table 3.3-41. Since the orifice listed in Table 3.3-41 of the LRA is only subject to a gas environment, and the applicant has corrected the error in Note (3), the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

The aging effects that result from contact of the RCS (non-Class 1 components) SSCs to the environments described in LRA Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 through 3.3-241, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.32.2.2 Aging Management Programs

LRA Section 2.3.3.32 and Table 3.3-41, pages 3.3-239 to 3.3-241, state that the following aging management programs are credited for managing the aging effects in the RCS (non-Class 1 components).

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-41, the staff concludes that the above identified AMPs will effectively manage the aging effects of the RCS (non-Class 1 components), and that there is reasonable assurance that the intended functions of the RCS (non-Class 1 components) will remain consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.32.3 Conclusions*

The staff reviewed the information in Section 2.3.3.32 and Table 3.3-41 of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RCS (non-Class 1 components) will be adequately managed, so that there is reasonable assurance that the system components 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).

**3.3.33 Recirculated Cooling Water System (Catawba Nuclear Station Only)**

*3.3.33.1 Technical Information in the Application*

No portion of the McGuire recirculated cooling water system is within the scope of license renewal. Only the Duke Class F portions of the recirculated cooling water system are in scope at Catawba. McGuire has no Class F components in the recirculated cooling water system.

The Catawba recirculated cooling water system is a closed cooling system that delivers clean, rust-inhibited cooling water of a regulated temperature to various equipment in the turbine buildings, auxiliary building, and service building. The recirculated cooling water system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this system are within the scope of license renewal per 10 CFR 54.4(a)(2).

3.3.33.1.1 Aging Effects

Components of the recirculated cooling water system are described in Section 2.3.3.33 of the LRA as being within the scope of license renewal, and subject to an AMR. Table 3.3-42, page 3.3-242, of the LRA lists individual components of the system, including pipe and valve bodies. Carbon steel components are subject to the aging effect of loss of material from external surfaces exposed to the sheltered environments. Carbon steel components are identified as being subject to loss of material and cracking from exposure to the internal environment of treated water.

3.3.33.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the recirculated cooling water system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the recirculated cooling water system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.33.2 Staff Evaluation*

The applicant described its AMR of the recirculated cooling water system for license renewal in two separate sections of its LRA, Section 2.3.3.33 and Table 3.3-42, page 3.3-242. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the recirculated cooling water system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.33.2.1 Aging Effects

The aging effects that result from contact of the recirculated cooling water SSCs to the environments described in Section 2.3.3.33 and Table 3.3-42, page 3.3-242, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.33.2.2 Aging Management Programs

Section 2.3.3.33 and Table 3.3-42, page 3.3-242, of the LRA state that the following aging management programs are credited for managing the aging effects in the recirculated cooling water system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-42, the staff concludes that the above identified AMPs will effectively manage the aging effects of the recirculated cooling water system, and that there is reasonable assurance that the intended functions of the recirculated cooling water system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.33.3 Conclusions*

The staff reviewed the information in Section 2.3.3.33 and Table 3.3-42, page 3.3-242, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the recirculated cooling water system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.34 Spent Fuel Cooling System

*3.3.34.1 Technical Information in the Application*

The McGuire spent fuel cooling system removes heat from the spent fuel pool and maintains the purity and optical clarity of the pool water for fuel handling operations. The purification loop provides an alternate means for removing impurities from either the refueling canal/transfer canal water during refueling, or the refueling water storage tank water following refueling. The fuel pool water also serves as a source of makeup water to the RCS during a standby shutdown system event. McGuire UFSAR Section 9.1.3, “Spent Fuel Cooling and Purification,” provides additional information concerning the McGuire spent fuel cooling system.

The Catawba spent fuel cooling system, in conjunction with the component cooling water system and nuclear service water system, is designed to remove heat from the spent fuel pool and maintain purity and optical clarity of the pool water during fuel handling operations. The purification loop provides an alternate means for removing impurities from either the refueling cavity/transfer canal water during refueling, or the refueling water storage tank water following refueling. Catawba UFSAR Section 9.1.3, “Spent Fuel Cooling and Purification,” provides additional information concerning the Catawba spent fuel cooling system.

3.3.34.1.1 Aging Effects

Components of the spent fuel cooling system are described in Section 2.3.3.34 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-43, pages 3.3-243 to 3.3-246, lists individual components of the system, including heat exchangers (channel heads, shells, tubes, and tubesheets), orifices, pump casings, spacers, pipe, tubing, and valve bodies. Stainless steel components are identified as being subject to the external environments of sheltered and reactor building with no aging effects identified. An internal or external environment of borated water or treated water causes the aging effects of loss of material and cracking in stainless steel components. Carbon steel components are subject to the aging effect of loss of material and cracking from exposure to internal and external surfaces from treated water environments. Carbon steel components are identified as being subject to loss of material from sheltered environments.

3.3.34.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the spent fuel cooling system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the spent fuel cooling system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.34.2 Staff Evaluation*

The applicant described its AMR of the spent fuel cooling system for license renewal in two separate sections of its LRA, Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 3.3-246. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the spent fuel cooling system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.34.2.1 Aging Effects

The aging effects that result from contact of the spent fuel cooling SSCs to the environments described in LRA Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 through 3.3-246, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.34.2.2 Aging Management Programs

LRA Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 3.3-246, state that the following aging management programs are credited for managing the aging effects in the spent fuel cooling system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Chemistry Control Program

The Fluid Leak Management Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-43, the staff concludes that the above identified AMPs will effectively manage the aging effects of the spent fuel cooling system, and that there is reasonable assurance that the intended functions of the spent fuel cooling system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.34.3 Conclusions*

The staff reviewed the information in LRA Section 2.3.3.34 and Table 3.3-43, pages 3.3-243 to 3.3-246. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the spent fuel cooling system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.35 Standby Shutdown Diesel

*3.3.35.1 Technical Information in the Application*

The standby shutdown diesel system is essentially the same, and performs the same function, for McGuire and Catawba. The standby shutdown diesel system provides an alternate and independent means of achieving and maintaining a hot standby condition for one or both units following a postulated fire event. The diesel provides power to the standby shutdown facility required components, instrumentation, and controls for a period of up to 72 hours.

3.3.35.1.1 Aging Effects

Components of the standby shutdown diesel system are described in Section 2.3.3.35 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-44, pages 3.3-247 to 3.3-255, lists individual components of the system, including cooling water filters, heat exchanger engine radiators, tubing, valve bodies, exhaust bellows, piping, silencers, duplex filters, flame arrestors, level glass, pipe, oil storage tanks, tank vents, pump casings, and oil filters. Stainless steel components exposed to internal environments of ventilation, yard, or sheltered exhibit no aging effects. Stainless steel components exposed to internal or external environments of fuel oil are subject to the loss of material aging effect. Stainless steel components exposed to an underground environment are subject to the aging effects of cracking and loss of material.

Internal surfaces of carbon steel components exposed to treated water are subject to cracking and loss of material. Carbon steel exposed to sheltered, yard, underground, or fuel oil internal or external environments exhibit the aging effect of loss of material. Carbon steel components exposed to ventilation or oil environments have no aging effects identified. Copper components exposed to an internal environment of treated water are subject to loss of material. Copper components exposed to ventilation or sheltered environments have no aging effects identified.

Brass components exposed to an internal environment of treated water are subject to loss of material and cracking. Exposure of brass components to a sheltered environment is not subject to any aging effects. Cast iron components exposed to internal or external environments of treated water or sheltered are subject to that aging effects of loss of material. Aluminum exposed to ventilation or sheltered environments have no aging effect identified.

Bronze components exposed to fuel oil environments demonstrate the aging effect of loss of material, while exposure of bronze to the sheltered environment has no aging effect identified. Wrought iron components exposed to internal or external environments of fuel oil or sheltered environments are subject to the aging effect of loss of material. Glass or acrylic components exposed to fuel oil, ventilation, or sheltered environments exhibit no aging effects.

3.3.35.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the standby shutdown diesel system:

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coatings Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the standby shutdown diesel system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.35.2 Staff Evaluation*

The applicant described its AMR of the standby shutdown diesel system for license renewal in two separate sections of its LRA, Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 3.3-255. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the standby shutdown diesel system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.35.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 3.3-255. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-5, additional information pertaining to LRA Table 3.3-44, "Aging Management Review Results — Standby Shutdown Diesel Generator, Exhaust Subsystem." This table indicated that components are subject to an internal environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560-20, MCFD-1560-01.00, MCFD-1560-02.00, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. The applicant was requested to provide justification for classifying the internal environment for these components as "ventilation." A similar question was asked about the diesel generator air intake and exhaust system components listed in LRA Table 3.3-14 (refer to Section 3.3.11.2.1 of this SER).

In its response dated, March 15, 2002, the applicant stated that the staff is correct that these components are subject to a sheltered internal environment. Duke's aging management review conservatively evaluated environments, such as tanks and piping that are open to atmosphere, as a ventilation environment. Although the tanks and piping are open to sheltered environments, they would not experience significant air exchange, and thus higher humidity and condensation could be present. The ventilation environment aging effect details account for the potential condensation, whereas the sheltered environment aging effect details do not. Loss of material and cracking due to alternate wetting and drying that concentrates contaminants are two aging effects considered plausible in a ventilation environment, but are not considered in sheltered environments. Loss of material due to selective leaching is another aging effect considered plausible in a ventilation environment, but is not considered in sheltered environments. Therefore, for conservatism, Duke chose to evaluate these component configurations using the ventilation environment aging management review details. The designation in the LRA table reflects this decision.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff requested the applicant to provide additional justification for claiming, in LRA Table 3.3-44, that carbon steel external components are subject to sheltered environments, while the internal environment is ventilation. The sheltered environment is subject to the aging effect of loss of material and managed by the “Inspection Program for Civil Engineering Structures and Components.” The staff considered this to be in conflict with Duke’s response that loss of material in sheltered environments is not considered an aging effect. The applicant was requested to clarify or justify how an “uncontrolled” sheltered environment is less conservative than a “controlled” ventilation environment, and causes no aging effects, or to revise the aging effects and AMPs listed in LRA Table 3.3-44 to be consistent with other sheltered environments listed in the tables. The staff further noted that its fundamental concern was that, for the diesel engine exhaust systems (which include no equipment (coolers or dryers) for controlling air quality), the internal environments are “sheltered,” not “ventilation,” and that the aging effects associated with the sheltered environment must be addressed for these internal surfaces.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant replied as follows:

> For Duke, a sheltered environment is an external environment for components inside a structure that may or may not be maintained by a ventilation system but are protected from the natural elements. Components in a sheltered environment could be wet from condensation or leakage that could promote aggressive corrosion, that left unmanaged, could result in a loss of the component intended function(s) during the period of extended operation. As such, the Inspection Program for Civil Engineering Structures and Components is credited to manage the aging effects on the external surfaces of components located in a sheltered environment.
>
> For components with an internal air environment open to the sheltered environment or yard environment (as is the case with the diesel exhaust), Duke classified the environment as a ventilation environment. Duke conservatively chose the ventilation environment because more aging mechanisms leading to aging effects are plausible and must be considered than in a sheltered environment. In our initial response to RAI 3.3-5, Duke tried to show that aging effects from some mechanisms are not plausible in a sheltered environment but could occur in a ventilation environment. Duke was providing examples to support our conservative position which we believe does not say that loss of material in a sheltered environment is not an aging effect.
>
> Duke evaluated the internal environment of the exhaust systems as a ventilation environment. The diesels operate periodically for short periods of time for testing but are primarily in standby. The

> internal environment is characterized as a warm, dry environment free from leaks and condensation. This environment does not preclude loss of material but does not promote the aggressive corrosion that left unmanaged would result in a loss of the component intended function(s) of the exhaust system components. Therefore, no aging effects requiring management during the period of extended operation were identified.

By letter dated July 9, 2002, the staff received this information from the applicant in official correspondence. The applicant confirmed that the internal environment is warm, dry, and free from leaks and condensation. Since this environment does not promote the aggressive corrosion that would result in a loss of the component intended function(s) of the exhaust system components, this issue is resolved.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.44-1, additional information pertaining to LRA Table 3.3-44, "Aging Management Review Results — Standby Shutdown Diesel Generator, Exhaust Subsystem." This table does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. The applicant was requested to identify where in the LRA the AMR results are for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting, and crevice corrosion, or to provide a justification for excluding this environment and aging effects from LRA Table 3.3-44 and an AMR.

In its response dated March 15, 2002, the applicant stated that the results of the aging management review for the internal surfaces of the standby shutdown diesel generator, exhaust subsystem are presented in Table 3.3-44 of the LRA. The diesel generators are normally in standby and are operated periodically for a short period of time for surveillance testing. During diesel operation, the exhaust portion of this system will be exposed to hot gasses containing moisture and particulates. Exposure duration of the exhaust components to the hot gasses containing moisture and particulates is insignificant when compared to the exposure time of these components to the cool, ventilation environment. As a result, the internal environment of hot gasses containing moisture and particulates was not considered in the aging management review to identify the aging effects requiring management. Therefore, LRA Table 3.3-44 listed ventilation as the internal environment. Since the components are used only during startup of the diesel generator, the staff agrees that ventilation is the normal internal environment.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.44-2, additional information pertaining to LRA Table 3.3-44, "Aging Management Review Results — Standby Shutdown Diesel Generator, Fuel Oil Subsystem." This table indicates that the shutdown diesel generator fuel oil valve bodies, fuel oil (duplex filters, Catawba only, on page 3.3-254 of the LRA) has a "PB," or pressure boundary, component function. This component also provides filtration of process fluids, so that downstream equipment and/or environments are protected. The applicant was requested to explain why this component does not have a "FI," or filtration, component function, as defined in the notes section for other AMR tables, or to correct the component functions for filters listed in LRA Table 3.3-44.

In its response dated March 15, 2002, the applicant stated that the LRA Table 3.3-44 entry "Valve Bodies, Fuel Oil (duplex filters) (Catawba only)" pertains to the valves associated with the duplex filter assembly, not the filter itself. Although not necessary, the valves were differentiated because they were the only valves in the system with the given material/environment combination. The duplex filter is addressed in the entry on page 3.3-249, “Filter, Duplex (mounting head),” of the LRA. The mounting head is the only passive, long-lived portion of the duplex filter. The staff’s evaluation of the applicant’s treatment of filters is documented in Section 2.1.3.2.1 of this SER. Since the applicant clarified that the PB function is provided by valves associated with the duplex filter assembly, and that the filter is not subject to an AMR since it is replaced during periodic diesel engine maintenance, the staff finds that its response is acceptable. The applicant addressed filters on page 2.1.2.1.2 of the LRA; the staff’s evaluation of the applicant’s treatment of filters is provided in Section 2.1.3.2.1 of this SER.

In its April 15, 2002, response to RAI 2.3.3.35-5 (see Section 2.3.3.35.2 of this SER), the applicant provided the following AMR results for carbon steel pipe (tubing) and pump casings to supplement the information provided in LRA Table 3.3-44:

| **Component Type** | **Component Function** | **Material** | **Internal Environment** / **External Environment** | **Aging Effects** | **Aging Management Programs and Activity** |
|---|---|---|---|---|---|
| Pipe | PB | CS | Treated Water | Cracking (Note 3) | Chemistry Control Program |
| | | | | Loss of Material | Chemistry Control Program |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |
| Pump Casing (cooling water) | PB | CS | Treated Water | Cracking (Note 3) | Chemistry Control Program |
| | | | | Loss of Material | Chemistry Control Program |
| | | | Sheltered | Loss of Material | Inspection Program for Civil Engineering Structures and Components |

The aging effects that result from contact of the standby shutdown diesel SSCs to the environments described in the applicant’s response to RAI 2.3.3.35-5, and LRA Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 through 3.3-255, are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.35.2.2 Aging Management Programs

LRA Section 2.3.3.35 and Table 3.3-44, pages 3.3-247 to 3.3-255, state that the following aging management programs are credited for managing the aging effects in the standby shutdown diesel system.

- Inspection Program for Civil Engineering Structures and Components
- Chemistry Control Program
- Preventive Maintenance Activities — Condenser Circulating Water System Internal Coatings Inspection

The Preventive Maintenance Activities — Condenser Circulating Water System Internal Coatings Inspection Program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

The staff reviewed the information in LRA Section 2.3.3.35; Table 3.3-44, pages 3.3-247 to 3.3-255; and Section B.3.6, "Chemistry Control Program." During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-6, additional information pertaining to LRA Table 3.3-44, "Aging Management Review Results — Standby Shutdown Diesel Generator." This table indicates that the cooling water and jacket water engine radiator heat exchanger has a function of HT that is managed by the Chemistry Control Program. Heat transfer monitoring is not identified as a capability of the Chemistry Control Program, as defined in Appendix B, Section B.3.6, of the LRA. The applicant was requested to explain how the Chemistry Control Program monitors the heat transfer function.

In its response dated March 15, 2002, the applicant stated that for the heat exchangers in the standby shutdown diesel generator, cooling water and jacket water heating subsystem, Duke determined that the component intended functions that must be maintained for the period of extended operation for these heat exchangers are heat transfer and pressure boundary. For heat exchangers, fouling is the only aging effect that will result in a loss of the intended function of heat transfer. Duke determined during the aging management review that fouling would not occur for these closed loop heat exchangers because there is constant flow through the heat exchangers, and the treated water in the system is filtered to remove particles. Therefore, no aging management program is required. Loss of material is an aging effect that could result in a loss of the intended function of pressure boundary for these heat exchangers during the period of extended operation. The Chemistry Control Program is credited as the aging management program to manage loss of material during the period of extended operation.

The staff agreed that the Chemistry Control Program will manage the loss of material because it provides for chemistry controls and the presence of corrosion inhibitors in the treated water to which the heat exchanger is exposed. However, the staff did not agree with the applicant's conclusion that fouling will not occur in the heat exchanger because of constant flow through the heat exchanger. The staff recognized that sufficient flow through the heat exchanger may prevent areas of stagnation in which fouling may occur. However, the applicant had not substantiated its conclusion with any operating experience, such as maintenance and surveillance results, to indicate that this activity had been successful in preventing fouling. With respect to the filtering of the treated water to remove particles, the staff recognized that particulates are removed through a filtering process. However, the applicant did not list or credit a periodic surveillance of the filter to ensure that the entrained particles did not create a high differential pressure and adversely affect flow through the heat exchanger. Therefore, this issue was characterized as SER open item 3.3.35.2-1.

In its response dated October 28, 2002, the applicant stated that fouling due to silting will be identified as an aging effect requiring management for the heat exchanger in the standby shutdown diesel cooling water and jacket water heating subsystem. The applicant further clarified that the standby shutdown diesel cooling water and jacket water heating subsystems are closed cooling water systems treated with corrosion inhibitors. These corrosion inhibitors preclude the formation of corrosion products, and the inhibitor concentration is maintained by the Chemistry Control Program. In addition, the second entry in Table 3.3-44, "Aging Management Results — Standby Shutdown Diesel," on page 3.3-247 of the LRA will be replaced with the following:

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effects | Aging Management Programs and Activities |
|---|---|---|---|---|---|
| Heat Exchanger Engine Radiator (tubes) | PB, HT | Cu | Treated Water | Loss of Material Fouling | Chemistry Control Program |
| | | | Ventilation | None Identified | None Required |

The staff finds that the clarifications and changes provided by the applicant are appropriate to ensure that the aging effects associated with the heat exchanger in the standby shutdown diesel cooling water and jacket water heating subsystem will be adequately managed during the period of extended operation. The identification of fouling as an aging effect, and its management through corrosion inhibitors monitored by the Chemistry Control Program, are acceptable because the program precludes the formation of corrosion products that can cause the fouling of the heat exchanger and adversely impact the heat transfer function. Therefore, open item 3.3.35.2-1 is closed.

Based on its review of LRA Table 3.3-44, and with the resolution of open item 3.3.35.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the standby shutdown diesel system, and that there is reasonable assurance that the intended functions of the standby shutdown diesel system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.35.3 Conclusions*

The staff reviewed the information in the applicant's response to RAI 2.3.3.35-5, and LRA Section 2.3.3.35 and Table 3.3-44. On the basis of its review, and with the resolution of open item 3.3.35.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the standby shutdown diesel system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.36 Turbine Building Sump Pump System (Catawba Nuclear Station Only)

*3.3.36.1 Technical Information in the Application*

No portion of the McGuire turbine building sump pump system is within the scope of license renewal. Only the Duke Class F portions of the turbine building sump pump system are in scope at Catawba. McGuire has no Class F components in the turbine building sump pump system.

The Catawba turbine building sump pump system serves as a collection point for the contents of liquid radwaste system sumps when the contents of the sumps contain less than predetermined levels of radiation, as sensed by radiation monitors in the discharge lines. The turbine building sump pump system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. To preclude these postulated failures, portions of this system are seismically designed (i.e., Duke Class F). All components within the seismically designed piping boundaries of this systems are within the scope of license renewal per 10 CFR 54.4(a)(2).

3.3.36.1.1 Aging Effects

Components of the turbine building sump pump system are described in Section 2.3.3.36 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-45, page 3.3-256, of the LRA lists individual components of the system, including pipe. Carbon steel components exposed to a raw water internal environment and a sheltered external environment are subject to loss of material aging effects.

3.3.36.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the turbine building sump pump system:

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Sump Pump Systems Inspection

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the turbine building sump pump system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.36.2 Staff Evaluation*

The applicant described its AMR of the turbine building sump pump system for license renewal in two separate sections of its LRA, Section 2.3.3.36 and Table 3.3-45, page 3.3-256. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the turbine building sump pump system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.36.2.1 Aging Effects

The aging effects that result from contact of the turbine building sump pump SSCs to the environments described in Section 2.3.3.36 and Table 3.3-45, page 3.3-256, of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.36.2.2 Aging Management Programs

Section 2.3.3.36 and Table 3.3-45, page 3.3-256, of the LRA state that the following aging management programs are credited for managing the aging effects in the turbine building sump pump system.

- Inspection Program for Civil Engineering Structures and Components
- Fluid Leak Management Program
- Sump Pump Systems Inspection

The Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Sump Pump Systems Inspection program are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.3-45, the staff concludes that the above identified AMPs will effectively manage the aging effects of the turbine building sump pump system, and that there is reasonable assurance that the intended functions of the turbine building sump pump system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.3.36.3 Conclusions*

The staff reviewed the information in Section 2.3.3.36 and Table 3.3-45, page 3.3-256, of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the turbine building sump pump system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.37 Turbine Building Ventilation System (McGuire Nuclear Station Only)

*3.3.37.1 Technical Information in the Application*

The Catawba turbine building ventilation system SCs are not within the scope of license renewal. The Catawba miscellaneous structures ventilation system that provides SSF HVAC is addressed in Section 2.3.3.25.

The McGuire turbine building ventilation system includes the HVAC system in the SSF, of which a portion is the standby shutdown facility HVAC system. The SSF HVAC portion of the turbine building ventilation system provides the heating, ventilation and air conditioning requirements for the SSF, and consists of air conditioning and ventilation subsystems. McGuire UFSAR Section 9.4.4, “Turbine Building,” provides additional information concerning the SSF HVAC portion of the McGuire turbine building ventilation system.

Components of the turbine building ventilation system are described in Section 2.3.3.37 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-46, page 3.3-257, of the LRA lists individual components of the system, including air handling units, ductwork, flexible connectors, and plenum sections. Galvanized steel and neoprene components are identified as being subject to the internal environment of ventilation, and the external sheltered environment with no aging effects identified.

The applicant stated that the SCs in this system are not subject to any aging effects. Therefore, no AMPs are necessary in the turbine building ventilation system.

*3.3.37.2 Staff Evaluation*

The applicant described its AMR of the turbine building ventilation system for license renewal in two separate sections of its LRA, Section 2.3.3.37 and Table 3.3-46, page 3.3-257. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the turbine building ventilation system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.37.2.1 Aging Effects

The applicant’s conclusion that no aging effects result from contact of the miscellaneous structures ventilation SSCs to the environments listed in Section 2.3.3.25 and Table 3.3-33, page 3.3-209, of the LRA is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff agrees with the applicant that there are no aging effects for the combination of materials and environments identified.

3.3.37.2.2 Aging Management Programs

There are no aging effects identified in this system. Therefore, no AMPs are required in the turbine building ventilation system.

*3.3.37.3 Conclusions*

The staff reviewed the information in Section 2.3.3.37 and Table 3.3-46, page 3.3-257, of the LRA. On the basis of its review, the staff concludes that the SCs in the turbine building ventilation system are not subject to any aging effects. Therefore, no AMPs are required in the turbine building ventilation system..

### 3.3.38 Waste Gas System

*3.3.38.1 Technical Information in the Application*

The McGuire waste gas system removes fission gasses from radioactive contaminated fluids and contains these gasses in holdup tanks indefinitely. Storage and subsequent decay of these gasses eliminates the need for regularly scheduled discharge of these radioactive gasses from the system into the atmosphere during normal plant operation. McGuire UFSAR Section 11.3, “Waste Gas System,” provides additional information concerning the McGuire waste gas system.

The Catawba waste gas system removes fission product gasses from radioactive fluids, and contains these gasses for a time sufficient to allow ample decay of the nuclides prior to release, in accordance with applicable NRC regulations. The system is designed to control and minimize releases of radioactive effluent to the environment by reducing the fission product gas concentration in the reactor coolant, which may escape during maintenance operations or from equipment leaks. Catawba UFSAR Section 11.3, “Waste Gas System,” provides additional information concerning the Catawba waste gas system.

3.3.38.1.1 Aging Effects

Components of the waste gas system are described in Section 2.3.3.38 of the LRA as being within the scope of license renewal, and subject to an AMR. LRA Table 3.3-47, pages 3.3-258 to 3.3-263, lists individual components of the system, including flow meters, hydrogen recombiners, hydrogen recombiner heat exchangers, hydrogen recombiner heaters, hydrogen recombiner separators, safety discs, orifices, pipe, strainers, tubing, heat exchangers, decay tanks, and valve bodies. Stainless steel components are identified as being subject to the internal or external environments of gas or sheltered with no aging effects identified. An internal or external environment of treated water causes the aging effects of loss of material, fouling, and cracking in stainless steel components. Internal or external surfaces of carbon steel components exposed to treated water, sheltered, or gas environments experience the aging effect of loss of material and cracking. Brass components exposed to an internal or external environment of treated water are subject to loss of material.

3.3.38.1.2 Aging Management Programs

The following AMPs are utilized to manage aging effects for the waste gas system:

- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

- Waste Gas System Inspection
- Chemistry Control Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of the waste gas system will be adequately managed by these aging management programs during the period of extended operation.

*3.3.38.2 Staff Evaluation*

The applicant described its AMR of the waste gas system for license renewal in two separate sections of its LRA, Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 to 3.3-263. The staff reviewed these sections of the LRA to determine whether the applicant had demonstrated that the effects of aging for the waste gas system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.38.2.1 Aging Effects

The staff reviewed the information in LRA Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 3.3-263. During its review, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3.47-1, additional information pertaining to LRA Table 3.3-47, "Aging Management Review Results — Waste Gas System." This table identifies an internal environment described as gas. The definition for air-gas environments identified at the beginning of the tables does not adequately describe the gas environment found in the waste gas system. The waste gas system contains mixed radioactive fission gasses (e.g., Kr, Xe, I, Cs), in addition to those listed in the air-gas definition. The applicant was requested to clarify if the air-gas environment described at the beginning of the tables includes fission gasses or to add a new definition for the gas environment found in the waste gas system.

In its response dated March 15, 2002, the applicant stated that the waste gas system continuously circulates nitrogen around the system loop. Hydrogen, containing oxygen and fission product gasses, is vented into the waste gas system from the volume control tanks of the CVCS. Additional oxygen is added immediately upstream of the recombiners to reduce the hydrogen concentrations in the waste gas stream to residual levels. As a result, the environment is compressed nitrogen gas containing fission product gasses, and is consistent with the definition of a gas environment on page 3.3-3 of the LRA. Since the response clarifies the definition of the air-gas environment as nitrogen gas containing fission product gasses, the staff finds its response acceptable.

By letter dated January 23, 2002, the staff requested, in RAI 3.3.47-2, additional information pertaining to LRA Table 3.3-47, "Aging Management Review Results — Waste Gas System." This table indicates that, for the Catawba plant, the orifices for waste gas compressor seal and makeup have a "PB," or pressure boundary component function. Typically, orifices also provide the function listed as "TH" (i.e., provide throttling so that sufficient flow and/or sufficient pressure is delivered, provide backpressure, provide pressure reduction, or provide differential pressure). The applicant was requested to explain why orifices in the Catawba waste gas system do not provide the function "TH," or to correct the component functions for orifices listed in LRA Table 3.3-47.

In its response dated March 15, 2002, the applicant stated that the waste gas compressor is a non-safety-related component that is not required to operate in support of any function related to 10 CFR 54.4(a)(1) of the Rule.  The components associated with the compressor are only required to maintain pressure boundary integrity in support of 10 CFR 54.4(a)(1)(iii).  Therefore, throttling is not a license renewal intended function of the seal and makeup orifices.  Since the intended function for the orifices is to maintain pressure boundary integrity only, and "TH" is not a license renewal intended function, the staff finds that the applicant's response clarifies and satisfactorily resolves this item.

In its April 15, 2002, response to RAI 2.3.3.38-1 (see Section 2.3.3.38.2 of this SER), the applicant provided the following AMR results for the waste gas separators:

| Component Type | Component Function | Material | Internal Environment / External Environment | Aging Effect | Aging Management Programs and Activities |
|---|---|---|---|---|---|
| Waste Gas Separators | PB | Synthetic Rubber* | Gas / Sheltered | None Identified / None Identified | None Required / None Required |
| Waste Gas Separators | PB | SS | Treated Water (unmonitored) / Sheltered | Cracking / Loss of Material / None Identified | Waste Gas System Inspection / Waste Gas System Inspection / None Required |

The aging effects that result from contact of the waste gas SSCs to the environments described in the applicant's response to RAI 2.3.3.38-1, and in LRA Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 through 3.3-263, are consistent with industry experience for these combinations of materials and environments.  On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.3.38.2.2 Aging Management Programs

LRA Section 2.3.3.38 and Table 3.3-47, pages 3.3-258 to 3.3-263, state that the following aging management programs are credited for managing the aging effects in the waste gas system.

- Galvanic Susceptibility Inspection
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Waste Gas System Inspection
- Chemistry Control Program

The Fluid Leak Management Program, Galvanic Susceptibility Inspection program, Chemistry Control Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging effects of several components in different structures and systems and are, therefore, considered common aging management programs.  The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

During its review of the information in LRA Section 2.3.3.38 and Tables 3.3-47, pages 3.3-258 to 3.3-263, the staff determined that additional information was needed to complete its review. By letter dated January 23, 2002, the staff requested, in RAI 3.3-6, additional information pertaining to Table 3.3-47, "Aging Management Review Results — Waste Gas System," identifies the hydrogen recombiner heat exchanger tubes as having a function of heat transfer. Heat transfer monitoring is not identified as a capability of the Chemistry Control Program, as defined in Appendix B, Section B.3.6 of the LRA. The applicant was requested to explain how the Chemistry Control Program monitors the heat transfer function.

In its response dated March 15, 2002, the applicant stated that for the hydrogen recombiner heat exchangers in the waste gas system found in Table 3.3-47 of the LRA, fouling was identified as an aging effect requiring management during the period of extended operation. The Chemistry Control Program is credited with managing this aging effect. The hydrogen recombiner heat exchangers are cooled by the component cooling system and could foul due to silting from corrosion product buildup. The component cooling system is a closed cooling water system that contains corrosion inhibitors to mitigate loss of material that would generate corrosion products that could be transported to, and foul, the hydrogen recombiner heat exchangers. The Chemistry Control Program monitors and controls the corrosion inhibitors to mitigate the generation of corrosion products, which would mitigate fouling of the hydrogen recombiner heat exchangers.

The staff finds that the applicant's response clarifies and satisfactorily resolves this item pertaining to the Chemistry Control Program. The staff's evaluation of the Waste Gas Systems Inspection program follows.

<u>Waste Gas System Inspection</u>

The applicant described its Waste Gas System Inspection in Section B.3.36 of LRA Appendix B. The applicant credits this program with managing the potential aging of waste gas system structures and components that are within the scope of license renewal. The inspection activity is a one-time volumetric or visual inspection to monitor for loss of material and cracking. The staff reviewed Section B.3.36 of LRA Appendix B to determine if the applicant had demonstrated that the waste gas 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).

In Section B.3.36 of LRA Appendix B, the applicant stated that the purpose of the Waste Gas System Inspection 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 any loss of material and cracking of system components within the scope of license renewal that are exposed to unmonitored treated water and gas environments. The applicant described unmonitored treated water as condensation of water vapor in the waste gas stream, and effluent from the recombiners and separators. The applicant described the gas environment as a combination of nitrogen, hydrogen, oxygen, and fission product gasses. The applicant stated that there is uncertainty as to whether exposure to these environments could cause cracking and/or loss of material for the waste gas system components, such that they would lose their pressure boundary intended function.

The waste gas system inspection activities use a combination of volumetric and/or visual examination of selected carbon steel, stainless steel, and brass components in the system. This is a one-time inspection activity. The applicant stated that, should industry experience, or evaluation of the inspection findings, indicate 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.

The staff's evaluation of the Waste Gas 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.

[Program Scope] Section B.3.36 of LRA Appendix B states that the scope of the waste gas system inspection activities includes the carbon steel, stainless steel, and brass materials that are exposed to unmonitored treated water environments, and carbon steel materials that are exposed to gas environments that are within the license renewal boundaries for the waste gas systems at Catawba and McGuire. The scope covers the components that rely on the waste gas system inspection activities for aging management; therefore, this is acceptable to the staff.

[Preventive or Mitigative Actions] There are no preventive or mitigative 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.3.36 of LRA Appendix B identifies loss of material and cracking as the parameters that can be detected by volumetric and/or visual inspection. Because these inspection techniques can be used to identify the degraded conditions noted by the applicant, such inspections of the waste gas system are acceptable to the staff.

[Detection of Aging Effects] Section B.3.36 of LRA Appendix B states that volumetric and/or visual inspection will detect loss of material and cracking of the components. Visual exams will be used in lieu of volumetric exams if access to the internal surfaces becomes available. The use of volumetric and/or visual inspection is considered by the staff to be a reasonable means of detecting these aging effects, and is consistent with NRC and industry guidance. Therefore, the staff finds this acceptable.

[Monitoring and Trending] Section B.3.36 of LRA Appendix B states that the one-time inspections will be performed as follows:

> (1) For the brass seal water control valves on the waste gas compressors at Catawba exposed to unmonitored treated water, an inspection will be performed on one of the two seal water control valves. The results of this inspection will be applied to the other brass seal water control valve.
>
> (2) For carbon steel components exposed to unmonitored treated water environments at each site, inspections will be performed on the lower portions of decay tanks and associated drain lines where condensate is likely to accumulate. One of eight possible locations at each site will be examined. The results of this inspection will be applied to the remainder of the waste gas system carbon steel components within the scope of license renewal exposed to unmonitored treated water environment.
>
> (3) For stainless steel components exposed to unmonitored treated water environments at each site, inspections will be performed on the seal water path of the waste gas compressor. One of two possible locations at each site will be examined. The results of this inspection will be applied to the remainder of the waste gas system stainless steel components within the scope of license renewal exposed to unmonitored treated water environment.
>
> (4) For the carbon steel components exposed to a gas environment at each site, an inspection will be performed on components located between the volume control tanks and the waste gas compressor phase separators. This section of the waste gas system contains a warm, moist gas that could result in condensation on the cooler internal surfaces of the carbon steel components. As a result, corrosion of the carbon steel surfaces is more likely due to the presence of moisture and would serve as a leading indicator for the remainder of the carbon steel components. The results of this inspection will be applied to the remainder of the waste gas system carbon steel components within the scope of license renewal exposed to gas environments.

The applicant stated that if no parameters are known that would distinguish the most susceptible locations for the above inspections, then the inspection locations will be based on accessibility and radiological concerns. By letter dated January 28, 2002, the staff requested, in RAI B.3.36-1, additional information about the criteria used to distinguish the most susceptible locations. In its response dated March 15, 2002, the applicant stated that the criteria could include component geometry, operating temperatures, system operation, and previous operating experience. These are appropriate criteria for determining the most susceptible locations; therefore, the staff finds the applicant's monitoring of aging effects to be acceptable.

Section B.3.36 of LRA Appendix B states that no actions are taken as part of the program to trend the inspection results, since this is a one-time inspection. If evaluation of the inspection findings indicates that continuation of the aging effects will cause a loss of intended function(s), additional inspections will be performed and/or corrective actions 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.3.36 of LRA Appendix B states that the acceptance criterion 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. The LRA also states that the engineering evaluation will determine whether continued aging could cause a loss of system intended function, or whether additional inspection is warranted, and that appropriate corrective action will be taken. Because it will maintain the system intended function, the staff finds the acceptance criterion to be reasonable and acceptable.

[Operating Experience]  Section B.3.36 of LRA Appendix B states that the waste gas system inspection is a one-time inspection for which there is no operating experience.  The staff finds this reasonable and acceptable.

FSAR Supplement:  The staff reviewed Appendix A of the LRA, Section 18.2.28 of the UFSAR supplement for McGuire, and Section 18.2.27 of the UFSAR for Catawba.  The staff finds that the summary description is consistent with the LRA and is, therefore, acceptable.

In conclusion, the staff has reviewed the information provided in the applicant’s response to RAI 2.3.3.38-1, 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 its review and the above evaluation, the staff finds that the Waste Gas System 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).

Based on its review of Table 3.3-47 and Appendix B of the LRA, the staff concludes that the above identified AMPs will effectively manage the aging effects of the waste gas system, and that there is reasonable assurance that the intended functions of the waste gas system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### *3.3.38.3 Conclusions*

The staff reviewed the information in the applicant’s response to RAI 2.3.3.38-1, and LRA Section 2.3.3.38 and Table 3.3-47.  On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the waste gas system will be adequately managed, so that there is reasonable assurance that the system components 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).

### 3.3.39 Auxiliary Systems — General

#### *3.3.39.1 Thermal Fatigue*

The applicant did not identify cracking due to thermal fatigue as an aging effect requiring management in Section 3.3 for the auxiliary system components.  However, the applicant identified thermal fatigue for piping systems designed to the requirements of ANSI B31.1 or ASME Section III, Subsection NC, or Subsection ND as a time-limited aging analysis (TLAA) in Section 4.3.2 of the LRA.  The staff’s evaluation of that TLAA is in Section 4.3 of this SER, and cracking due to thermal fatigue, as it applies to auxiliary system components, will not be discussed further in this section of the SER.

#### *3.3.39.2 Scoping Issues Related to Aging Management Programs for Auxiliary Systems*

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related systems, structures, and components (SSCs) whose failure could prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1)(i), (ii), or (iii).  By letter dated

January 23, 2002, the staff requested additional information, per RAI 3.3-2, as to whether the scope of the auxiliary systems discussed in Section 3.3 of the LRA includes any seismic II over I SSCs, as described in position C.2 of Regulatory Guide 1.29. In addition, the applicant was requested to clarify how the AMPs provided in tables of the LRA Section 3.3 apply to those seismic II over I piping systems to assure that plausible aging effects associated with those piping systems, if any, will be appropriately managed.

The applicant responded to this RAI in a letter dated April 15, 2002, by referring to its response to RAIs 2.1-2.a and 2.1-2.b that provide information on scoping seismic II over I SSCs. The applicant's response to RAI 2.1-2.a also provides a complete list of piping systems included within the scope of license renewal that fall into the category of seismic II over I SSCs. The staff's evaluation of the applicant's response to RAIs 2.1-2.a and 2.1-2.b concerning the scoping and screening methodology for identifying seismic II over I SSCs is in Section 2.1 of this SER, and will not be discussed further in this section of the SER. In addition, in its response to RAI 3.3-2, the applicant stated that the AMPs included in LRA Section 3.3 tables also apply to seismic II over I piping systems. The applicant further stated that Function 7 of Table 3.5-3 of the LRA is applicable for seismic II over I pipe supports. The aging effects of those pipe supports are managed by the AMP listed in the table for that entry.

Based on the above discussion, the staff finds the applicant's response clarifies and satisfactorily resolves the concern documented in RAI 3.3-2. The applicant's response ensures that plausible aging effects associated with seismic II over I SSCs, as they apply to auxiliary systems, will be appropriately managed and, therefore, is acceptable.

*3.3.39.3 Ventilation Systems Flexible Connectors*

Numerous ventilation systems included in Section 3.3 of the LRA do not list elastomer components associated with the ventilation systems. Normally, ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are hardening and loss of material.

By letter dated January 23, 2002, the staff requested, in RAI 3.3-1, the applicant to indicate where in the LRA the aging effects of hardening and loss of material to elastomer components, such as duct seals, flexible collars, rubber boots, etc., were addressed.

In its response dated April 15, 2002, the applicant acknowledged that flexible connectors were inadvertently omitted from the application for the auxiliary building, control area, diesel building, and fuel handling building or fuel handling area ventilation systems. LRA Tables 3.3-1, 3.3-11, 3.3-13, and 3.3-28 were subsequently revised to include AMR results for these components. However, no aging effects were identified.

In electronic correspondence dated May 2, 2002 (ADAMS Accession No. ML021440217), the staff requested the applicant to explain why no aging effects or AMP were identified for the elastomer components in sheltered environments in the revised tables provided on April 15, 2002.

In electronic correspondence dated May 10, 2002 (ADAMS Accession No. ML021440236), the applicant stated that the aging effects for loss of material and change in material properties (hardening) from exposure to ambient environmental conditions at the locations within the plant were evaluated. The results of this evaluation showed that the internal and external temperature and radiation levels at these flexible connector locations are well below those known to be an aging concern for the period of extended operation. No aging effects were, therefore, identified in the LRA. By letter from the applicant dated July 9, 2002, the staff received this explanation in official correspondence. Since the applicant explained that the internal and external environments do not pose an aging concern for the period of extended operation, the staff finds that no aging effects are expected. This issue is resolved.

### *3.3.39.4 Aging Management Review for Closure Bolting in Auxiliary Systems*

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in Sections 3.2, 3.3, and 3.4 of the LRA that list closure bolting as components subject to an AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3, and 3.4 of the LRA do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

#### 3.3.39.4.1 Aging Effects

In its response to RAI 3.2-1 dated April 15, 2002, the applicant indicated that non-class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures, and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure in accordance with the design codes and, therefore, are not subject to an aging management review.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid, while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system made from the same material and exposed to the same environment. Programs for the system (i.e., Chemistry Control Program and Fluid Leak Management Program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-class 1 bolted closures are loss of material of carbon and low-alloy steel, and cracking of carbon, low-alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, Duke determined the following are the aging effects requiring management for carbon and low-alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments identified.

3.3.39.4.2 Aging Management Programs

The applicant indicated that the Fluid Leak Management Program will manage loss of material of non-class 1 bolted closures in the reactor and auxiliary buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in LRA Appendix B, Section B.3.15, for McGuire and Catawba.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in LRA Appendix B, Section B.3.21, for McGuire and Catawba.

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for non-Class 1 closure bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

3.3.39.4.3 Conclusions

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems, as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with non-Class 1 closure bolts will be adequately managed, so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.4 Steam and Power Conversion Systems

The applicant described its AMR of the steam and power conversion systems (SPCSs) for license renewal in Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4, "Aging Management of Steam and Power Conversion Systems," of its LRA. Section 3.4 of the LRA defined the external and internal environments applicable to the SPCS as follows—

- 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.
- Sheltered environment — The ambient conditions within the sheltered environment may or may not be controlled. The sheltered environment atmosphere is a moist air environment. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.
- 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.
- Oil and Fuel Oil — Lubricating oil is an organic fluid used to reduce friction between moving parts. Fuel oil is the fuel used for the emergency diesel generators.

The staff has reviewed Sections 2.3.4 and 3.4 of the application to determine whether the applicant has provided adequate information to meet the requirements of 10 CFR 54.21(a)(3) for managing the aging effects of the SPCSs for license renewal.

### 3.4.1 Auxiliary Feedwater System

The auxiliary feedwater system is described in LRA Section 2.3.4.1, "Auxiliary Feedwater System." The applicant provided the results of its AMR of the auxiliary feedwater system for license renewal in Table 3.4-1 of the LRA.

#### *3.4.1.1 Technical Information in the Application*

The auxiliary feedwater system is a nuclear safety-related system that serves as a back up to the feedwater system to ensure the safety of the plant and protection of equipment. The auxiliary feedwater system is essential to prevent an unacceptable decrease in the steam generator water levels, to reverse the rise in reactor coolant temperature, to prevent the pressurizer from filling to a water solid condition, and to establish stable hot standby conditions. The auxiliary feedwater system can be used during an emergency, as well as during normal startup and shutdown operations. The auxiliary feedwater system is essentially the same, and provides the same functions, at both McGuire and Catawba. Section 10.4.10 of the McGuire UFSAR and Section 10.4.9 of the Catawba UFSAR provide additional information on the auxiliary feedwater system. The mechanical components subject to aging management review, their intended functions, and materials of construction for the auxiliary feedwater system are listed in Table 3.4-1 of the LRA.

3.4.1.1.1 Aging Effects

The materials of construction for the auxiliary feedwater SSCs are carbon steel and stainless steel.

A description of internal environments for the auxiliary feedwater system is provided in Table 3.4-1 of the LRA. The auxiliary feedwater system components are exposed to treated water and lubricating oil environments.

External surfaces of the structures and components in the auxiliary feedwater system are exposed to sheltered ambient air, oil, and reactor building environments, which are discussed in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the auxiliary feedwater SSCs that require management:

- loss of material, cracking, and fouling of stainless steel components in treated water environment
- loss of material from carbon steel components in reactor building, sheltered air, and treated water environments

3.4.1.1.2 Aging Management Programs

The applicant identified the following aging management programs to manage the aging effects for the auxiliary feedwater system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program (applicable to Catawba only)
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, "Chemistry Control Program," Section B.3.14, "Flow-Accelerated Corrosion Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

*3.4.1.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the auxiliary feedwater system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.1.2.1 Aging Effects

The aging effects that result from contact of the auxiliary feedwater SSCs with the environments shown in Table 3.4-1 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.1.2.2 Aging Management Programs

Table 3.4-1 of the LRA states that the following aging management programs are credited for managing the aging effects of the auxiliary feedwater system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program (applicable to Catawba only)
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Flow-Accelerated Corrosion Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER. Although the applicant proposes to mitigate loss of material of the carbon steel piping components by chemistry control, the staff believes that the effectiveness of the mitigation should be verified by implementing a one-time inspection of the internal surfaces of these components. This was characterized as SER open item 3.4.1.2.2-1.

In its response dated October 28, 2002, the applicant stated that it had searched the operating experience database to determine if there had been any component failures, relevant industry operating experience, or problems discovered during routine maintenance and testing. The applicant did not find any loss of the component intended functions of the auxiliary feedwater system components that could be attributed to the inadequacy of the chemistry control program. The applicant stated that routine maintenance of other secondary system components, such as the steam generators and main turbine, provide additional operating experience because they do operate during start up and shutdown and are of the same chemistry as the feedwater system and other secondary side systems. These secondary systems have also shown no degradation affected by water chemistry.

During a meeting on September 18, 2002 (summarized by memorandum dated November 18, 2002), the staff indicated that the routine inspections of the secondary systems would not be sufficient as an alternative to the one-time inspection, without proper documentation. The staff would find the routine inspections acceptable if the applicant would commit to document inspection results of the auxiliary feedwater system and main feedwater system to demonstrate that there are no aging effects occurring, and that the chemistry control program is effective. The staff also stated that the inspection results should be available for the future NRC inspection. In its October 28, 2002, response to the open item, the applicant augmented Section 18.3 of the McGuire FSAR supplement with the following:

> Visual inspections of the interior surfaces of auxiliary feedwater system and main feedwater system components and piping will be performed when available. The inspection results will be

> documented in writing and available for inspection 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).

The applicant augmented Section 18.3 of the Catawba FSAR supplement with the following:

> Visual inspections of the interior surfaces of auxiliary feedwater system and main feedwater system components and piping will be performed when available. The inspection results will be documented in writing and available for inspection 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 staff finds the applicant's augmented Catawba and McGuire FSAR supplements acceptable because the applicant will inspect these internal surfaces specifically for aging effects (loss of material) and will document its findings in the inspection procedure. This deliberate inspection will provide an opportunity to verify that the Chemistry Control Program is effective, and thereby satisfies the intent of the one-time inspection. However, the staff notes that, should the applicant identify loss of material or other aging effects it currently believes are being effectively managed by the Chemistry Control Program, then corrective actions may be required in accordance with 10 CFR Part 50, Appendix B, to repair the degraded condition. Additionally, corrective action will be necessary to prevent further age-related degradation from occurring. This may involve identification of an additional AMP or modification to the Chemistry Control Program. The staff concludes that open item 3.4.1.2.2-1 is closed.

Based on its review of LRA Table 3.4-1, and with the resolution of open item 3.4.1.2.2-1, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary feedwater system, and that there is reasonable assurance that the intended functions of the auxiliary feedwater system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.1.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-1, "Auxiliary Feedwater System." On the basis of its review, and with the resolution of open item 3.4.1.2.2-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary feedwater system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.2 Auxiliary Steam System

The auxiliary steam system is described in LRA Section 2.3.4.2, "Auxiliary Steam System." The applicant described the results of its AMR of the auxiliary steam system for license renewal in Table 3.4-2, "Aging Management Review Results — Auxiliary Steam System," of the LRA.

*3.4.2.1 Technical Information in the Application*

The auxiliary steam system provides steam to various plant equipment, as required, during all modes of plant operation, including condensate clean up, start up, normal operation, and shutdown. The auxiliary steam system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components subject to an AMR, their intended functions, and their materials of construction are listed in Table 3.4-2 of the LRA.

3.4.2.1.1 Aging Effects

The materials of construction for the auxiliary steam SSCs are brass, carbon steel, copper, and stainless steel. A description of internal and external environments for the auxiliary steam system is provided in Table 3.4-2 of the LRA. The auxiliary steam system components are internally exposed to treated water and steam environments. External surfaces of the structures and components in the auxiliary steam system are exposed to sheltered and yard environments, which are discussed in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the auxiliary steam SSCs that require management:

- loss of material and cracking of brass and stainless steel components in treated water and steam environments
- loss of material from carbon steel, copper, and brass components in sheltered air and treated water/steam environments
- loss of material from carbon steel in yard (trench) (Catawba only)

The LRA did not identify an aging effect for the stainless steel components exposed to sheltered environment for the auxiliary steam system.

3.4.2.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the auxiliary steam system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, "Chemistry Control Program," Section B.3.14, "Flow-Accelerated Corrosion Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

*3.4.2.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the auxiliary steam system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.1 Aging Effects

The aging effects that result from contact of the auxiliary steam SSCs with the environments shown in Table 3.4-2 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.2.2.2 Aging Management Programs

Table 3.4-2 of the LRA states that the following AMPs are credited for managing the aging effects of loss of material and cracking for the auxiliary steam system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Flow-Accelerated Corrosion Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-2, the staff concludes that the above identified AMPs will effectively manage the aging effects of the auxiliary steam system, and that there is reasonable assurance that the intended functions of the auxiliary steam system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.2.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-2, "Auxiliary Steam System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the auxiliary steam system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.3 Condensate System

The condensate system is described in LRA Section 2.3.4.3, "Condensate System." The applicant described the results of its AMR of the condensate system for license renewal in Table 3.4-3 of the LRA.

*3.4.3.1 Technical Information in the Application*

The condensate system provides water to various plant equipment, as required, during all modes of plant operation, including condensate cleanup, startup, normal operation, and shutdown. The condensate system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for the Catawba condensate system subject to aging management review, their intended functions, and materials of construction for the condensate system are listed in Table 3.4-3 of the LRA. No portion of the McGuire condensate system is within the scope of license renewal.

3.4.3.1.1 Aging Effects

The material of construction for the condensate SSCs is carbon steel. A description of internal environments for the condensate system is provided in Table 3.4-3 of the LRA. The condensate system components are internally exposed to a treated water environment. External surfaces of the structures and components in the condensate system are exposed to the sheltered environment which is discussed in Section 3.4.1 of the LRA.

Loss of material in carbon steel components in sheltered and treated water environments was identified as the only aging effect associated with the condensate SSCs that requires management.

3.4.3.1.2 Aging Management Programs

The applicant identified the following AMPs to manage the aging effect of loss of material for the condensate system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, "Chemistry Control Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

*3.4.3.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the condensate system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3.2.1 Aging Effects

The aging effect of loss of material that results from contact of the condensate SSCs with the environments shown in Table 3.4-3 of the LRA is consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effect listed is appropriate for the combination of materials and environments identified.

3.4.3.2.2 Aging Management Programs

Table 3.4-3 of the LRA states that the following AMPs are credited for managing the aging effect of loss of material for the condensate system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-3, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condensate system, and that there is reasonable assurance that the intended functions of the condensate system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.3.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-3, "Condensate System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effect associated with the condensate system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.4 Condensate Storage System

The condensate storage system is described in LRA Section 2.3.4.4, "Condensate Storage System." The applicant described the results of its AMR of the condensate storage system for license renewal in Table 3.4-4 of the LRA.

*3.4.4.1 Technical Information in the Application*

The condensate storage system provides a source of water for various plant equipment, as required, during all modes of plant operation, including condensate clean up, start up, normal operation, and shutdown. The condensate storage system is a non-safety-related system whose postulated failure could prevent satisfactory accomplishment of certain safety-related functions. The mechanical components for the Catawba condensate storage system subject to aging management review, their intended functions, and materials of construction for the condensate storage system are listed in Table 3.4-4 of the LRA. No portion of the McGuire condensate storage system is within the scope of license renewal.

3.4.4.1.1 Aging Effects

The material of construction for the condensate storage SSCs is carbon steel. A description of the internal environments for the condensate storage system is provided in Table 3.4-4 of the LRA. The condensate storage system components are internally exposed to a treated water environment. External surfaces of the structures and components are exposed to a sheltered environment, which is discussed in Section 3.4.1 of the LRA.

Loss of material for carbon steel components in sheltered and treated water environments was identified as the only aging effect associated with the condensate storage SSCs that requires management.

3.4.4.1.2 Aging Management Programs

The applicant identified the following AMPs to manage the aging effect of loss of material for the condensate storage system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, "Chemistry Control Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

*3.4.4.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the condensate storage system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.4.2.1 Aging Effects

The aging effect that results from contact of the condensate storage SSCs with the environments shown in Table 3.4-4 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.4.2.2 Aging Management Programs

Table 3.4-4 of the LRA states that the following AMPs are credited for managing the aging effect of loss of material for the condensate storage system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common aging management programs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-4, the staff concludes that the above identified AMPs will effectively manage the aging effects of the condensate storage system, and that there is reasonable assurance that the intended functions of the condensate storage system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.4.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-4, "Condensate Storage System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effect associated with the condensate storage system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.5 Feedwater System

The feedwater system is described in LRA Section 2.3.4.5, "Feedwater System." The applicant described the results of its AMR of the feedwater system for license renewal in Table 3.4-5 of the LRA.

*3.4.5.1 Technical Information in the Application*

The feedwater system takes treated condensate system water, heats it further to improve the plant's thermal cycle efficiency, and delivers it at the required flow rate, pressure, and temperature to the steam generators. The feedwater system is designed to maintain proper water levels in the steam generators with respect to reactor power output and turbine steam requirements. The mechanical components subject to an AMR, their intended functions, and materials of construction for the feedwater system are listed in Table 3.4-5 of the LRA.

3.4.5.1.1 Aging Effects

The materials of construction for the feedwater SSCs are carbon steel, low-alloy steel, and stainless steel.

A description of internal and external environments is provided in Table 3.4-5 of the LRA. The feedwater system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to the reactor building, sheltered, and yard environments, as defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the feedwater SSCs that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel and low-alloy steel components in the treated water, reactor building, sheltered, and yard atmosphere/weather environments

The LRA did not identify an aging effect for the stainless steel components exposed to the external environments, such as reactor building, sheltered, and yard atmosphere/weather environments.

3.4.5.1.2 Aging Management Programs

The applicant identified the following AMPs to manage the aging effects of cracking and loss of material for the feedwater system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, “Chemistry Control Program,” Section B.3.14, “Flow-Accelerated Corrosion Program,” Section B.3.15, “Fluid Leak Management Program,” and Section B.3.21, “Inspection Program for Civil Engineering Structures and Components.”

To manage the aging effects for the low-alloy steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program. To manage the aging effects for carbon steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program and the Flow-Accelerated Corrosion Program.

To manage the aging effects for the carbon steel and low-alloy steel components exposed to an external environment of borated water leaks in the reactor building, the applicant identified the Fluid Leak Management Program and Inspection Program for Civil Engineering Structures and Components.

To manage the aging effects for the carbon steel and low-alloy steel components exposed to the external environments of sheltered and yard, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

### *3.4.5.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the feedwater system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.4.5.2.1 Aging Effects

The aging effects that result from contact of the feedwater SSCs with environments as shown in Table 3.4-5 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.4.5.2.2 Aging Management Programs

Table 3.4-5 of the LRA states that the following aging management programs are credited for managing the aging effects of cracking and loss of material for the feedwater system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Flow-Accelerated Corrosion Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-5, the staff concludes that the above identified AMPs will effectively manage the aging effects of the feedwater system, and that there is reasonable assurance that the intended functions of the feedwater system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### *3.4.5.3 Conclusions*

The staff reviewed the information in Table 3.4-5, "Feedwater System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the feedwater system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.6 Feedwater Pump Turbine Exhaust System

The feedwater pump turbine exhaust system is described in LRA Section 2.3.4.6, "Feedwater Pump Turbine Exhaust System." The applicant described the results of its AMR of the feedwater pump turbine exhaust system for license renewal in LRA Table 3.4-6.

#### *3.4.6.1 Technical Information in the Application*

The feedwater pump turbine exhaust system provides a flow path for the exhaust steam from the turbine-driven auxiliary feedwater pump turbine. The steam to the turbine-driven auxiliary feedwater pump turbine is provided by the main steam system. Catawba UFSAR Section 10.3, "Main Steam System," provides additional information concerning the design and operation of these systems. The mechanical components subject to an AMR, their intended functions, and materials of construction for the feedwater pump turbine exhaust system are listed in Table 3.4-6 of the LRA

##### 3.4.6.1.1 Aging Effects

The material of construction for the feedwater pump turbine exhaust SSCs are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-6 of the LRA. The feedwater pump turbine exhaust system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to the sheltered and yard environments, as defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the feedwater pump turbine exhaust SSCs, that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel in treated water, sheltered, and yard atmosphere/weather environments

The applicant did not identify an aging effect for the stainless steel components exposed to a sheltered environment.

##### 3.4.6.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the feedwater pump turbine exhaust system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program (McGuire only)
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA

Section B.3.6, “Chemistry Control Program,” Section B.3.14, “Flow-Accelerated Corrosion Program,” Section B.3.15, “Fluid Leak Management Program,” and Section B.3.21, “Inspection Program for Civil Engineering Structures and Components.”

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program.

To manage the aging effects for the carbon steel pipe (McGuire only) exposed to an internal environment of treated water, the applicant identified the Flow-Accelerated Corrosion Program.

To manage the aging effects for the outside surface of the carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the Fluid Leak Management Program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered and yard, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

*3.4.6.2 Staff Evaluation*

The staff reviewed the results of the applicant’s AMR to determine whether the applicant had demonstrated that the effects of aging for the feedwater pump turbine exhaust system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.6.2.1 Aging Effects

The aging effects that result from contact of the feedwater pump turbine exhaust SSCs with environments as shown in Table 3.4-6 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.6.2.2 Aging Management Programs

Table 3.4-6 of the LRA states that the following AMPs are credited for managing the aging effects of cracking and loss of material for the feedwater pump turbine exhaust system components:

- Chemistry Control Program
- Flow-Accelerated Corrosion Program (McGuire only)
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Flow-Accelerated Corrosion Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-6, the staff concludes that the above identified AMPs will effectively manage the aging effects of the feedwater pump turbine exhaust system, and that there is reasonable assurance that the intended functions of the feedwater pump turbine exhaust system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.6.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-6, "Feedwater Pump Turbine Exhaust System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the feedwater pump turbine exhaust system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.7 Main Steam System

The main steam system is described in LRA Section 2.3.4.8, "Main Steam System," The applicant described the results of its AMR of the main steam system for license renewal in Table 3.4-7 of the LRA.

*3.4.7.1 Technical Information in the Application*

The main steam system dissipates heat from the RCS, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, minimizes the containment temperature increase associated with a main steam line rupture within containment, and provides steam to the turbine-driven auxiliary feedwater pump, as needed. The mechanical components subject to an AMR, their intended functions, and materials of construction for the main steam system are listed in Table 3.4-7 of the LRA.

3.4.7.1.1 Aging Effects

The materials of construction for the main steam SSCs are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-7 of the LRA. The main steam system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to reactor building, sheltered, and yard environments. These environments are defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the main steam SSCs that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel components in the treated water, reactor building, sheltered, and yard environments

The applicant did not identify an aging effect for the stainless steel components exposed to the reactor building, sheltered, and yard environments for the main steam system.

#### 3.4.7.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the main steam system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, Chemistry Control Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program.

To manage the aging effects for the carbon steel components exposed to an external environment of borated water leaks in the sheltered and reactor building, the applicant identified the Fluid Leak Management Program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered, reactor building, and yard, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

### *3.4.7.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the main steam system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.4.7.2.1 Aging Effects

The aging effects that result from contact of the main steam SSCs with environments as shown in Table 3.4-7 of the LRA are consistent with industry experience for these combinations of materials and environments.  On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.7.2.2 Aging Management Programs

Table 3.4-7 of the LRA states that the following AMPs are credited for managing the aging effects of cracking and loss of material for the main steam system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common AMPs.  The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system.  The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-7, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam system, and that there is reasonable assurance that the intended functions of the main steam system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.7.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-7, "Main Steam System."  On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.8 Main Steam Supply to Auxiliary Equipment System

The main steam supply to auxiliary equipment system is described in LRA Section 2.3.4.9, "Main Steam Supply to Auxiliary Equipment System."  The applicant described the results of its AMR of the main steam supply to auxiliary equipment system for license renewal in Table 3.4-8 of the LRA.

*3.4.8.1 Technical Information in the Application*

The main steam supply to auxiliary equipment transfers steam to the turbine driven auxiliary feedwater pump turbine, so that the design bases of the auxiliary feedwater system can be met. Catawba and McGuire UFSAR Section 10.3, "Main Steam Supply System," provides additional information concerning the main steam supply to auxiliary equipment.  The mechanical components subject to an AMR, their intended functions, and materials of construction for the main steam supply to auxiliary equipment system are listed in Table 3.4-8.

3.4.8.1.1 Aging Effects

The materials of construction for the main steam supply to auxiliary equipment SSCs are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-8 of the LRA. The main steam supply to auxiliary equipment system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to the sheltered environment, which is defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the main steam supply to auxiliary equipment SSCs that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel components in the treated water and sheltered environments

The applicant did not identify an aging effect for the stainless steel components exposed to the sheltered environment for the main steam supply to auxiliary equipment system.

3.4.8.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the main steam supply to auxiliary equipment system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA Section B.3.6, "Chemistry Control Program," Section B.3.15, "Fluid Leak Management Program," and Section B.3.21, "Inspection Program for Civil Engineering Structures and Components."

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program.

To manage the aging effects for the outside surface of carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the Fluid Leak Management Program.

To manage the aging effects for the outside surface of the carbon steel components exposed to the sheltered environment, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

### *3.4.8.2 Staff Evaluation*

The staff reviewed the results of the applicant's AMR to determine whether the applicant had demonstrated that the effects of aging for the main steam supply to auxiliary equipment system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.4.8.2.1 Aging Effects

The aging effects that result from contact of the main steam supply to auxiliary equipment SSCs with environments as shown in Table 3.4-8 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

#### 3.4.8.2.2 Aging Management Programs

Table 3.4-8 of the LRA states that the following AMPs are credited for managing the aging effects of cracking and loss of material for the main steam supply to auxiliary equipment system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-8, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam supply to auxiliary equipment system, and that there is reasonable assurance that the intended functions of the main steam supply to auxiliary equipment system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### *3.4.8.3 Conclusions*

The staff reviewed the information in LRA Table 3.4-8, "Main Steam Supply to Auxiliary Equipment System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam supply to auxiliary equipment system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.9 Main Steam Vent to Atmosphere System

The main steam vent to atmosphere system is described in LRA Section 2.3.4.10, "Main Steam Vent to Atmosphere System." The applicant described the results of its AMR of the main steam vent to atmosphere system for license renewal in Table 3.4-9 of the LRA.

#### *3.4.9.1 Technical Information in the Application*

The main steam vent to atmosphere system dissipates heat from the RCS, provides main steam overpressure protection, minimizes positive reactivity effects associated with a main steam line rupture, and minimizes the containment temperature increase associated with a main steam line rupture within containment. Catawba and McGuire UFSAR Section 10.3, "Main Steam Supply System," provides additional information concerning the main steam vent to atmosphere equipment. The mechanical components subject to an AMR review, their intended functions, and materials of construction for the main steam vent to atmosphere system are listed in LRA Table 3.4-9.

##### 3.4.9.1.1 Aging Effects

The materials of construction for the main steam vent to atmosphere SSCs are carbon steel and stainless steel.

A description of internal and external environments is provided in Table 3.4-9 of the LRA. The main steam vent to atmosphere system components are internally exposed to treated water. External surfaces of the structures and components that require an AMR are exposed to sheltered and yard environments. These environments are defined in Section 3.4.1 of the LRA.

The applicant identified the following aging effects associated with the main steam vent to atmosphere SSCs that require management:

- cracking and loss of material of stainless steel components in the treated water environment
- loss of material from carbon steel components in the treated water, sheltered, and yard environments

The applicant did not identify an aging effect for the stainless steel components exposed to the sheltered environment for the main steam vent to atmosphere system.

##### 3.4.9.1.2 Aging Management Programs

The applicant identified the following AMPs to manage aging effects for the main steam vent to atmosphere system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

A description of these AMPs, along with the applicant's discussion of how the identified aging effects will be effectively managed for the period of extended operation, is provided in LRA

Section B.3.6, “Chemistry Control Program,” Section B.3.15, “Fluid Leak Management Program,” and Section B.3.21, “Inspection Program for Civil Engineering Structures and Components.”

To manage the aging effects for the carbon steel and stainless steel components exposed to an internal environment of treated water, the applicant identified the Chemistry Control Program.

To manage the aging effects for the outside surface of the carbon steel components exposed to borated water leaks in the sheltered environment, the applicant identified the Fluid Leak Management Program.

To manage the aging effects for the carbon steel components exposed to the external environments of sheltered and yard, the applicant identified the Inspection Program for Civil Engineering Structures and Components.

*3.4.9.2 Staff Evaluation*

The staff reviewed the results of the applicant’s AMR to determine whether the applicant had demonstrated that the effects of aging for the main steam vent to atmosphere system will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.9.2.1 Aging Effects

The aging effects that result from contact of the main steam vent to atmosphere SSCs with environments as shown in Table 3.4-9 of the LRA are consistent with industry experience for these combinations of materials and environments. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effects listed are appropriate for the combination of materials and environments identified.

3.4.9.2.2 Aging Management Programs

Table 3.4-9 of the LRA states that the following AMPs are credited for managing the aging effects of cracking and loss of material for the main steam vent to atmosphere system components:

- Chemistry Control Program
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components

The Chemistry Control Program, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components are credited with managing the aging of several components in different structures and systems and are, therefore, considered as common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for this system. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

Based on its review of LRA Table 3.4-9, the staff concludes that the above identified AMPs will effectively manage the aging effects of the main steam vent to atmosphere system, and that there is reasonable assurance that the intended functions of the main steam vent to atmosphere system will be maintained consistent with the current licensing basis during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.4.9.3 Conclusions*

The staff reviewed the information in Table 3.4-9, "Main Steam Vent to Atmosphere System." On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the main steam vent to atmosphere system will be adequately managed, so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.4.10 Aging Management Review for Closure Bolting in Steam and Power Conversion Systems

Although the LRA provided AMR results for Class 1 bolting, it did not address bolting for non-Class 1 components. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, additional information that pertains to tables in LRA Sections 3.2, 3.3, and 3.4 that list closure bolting as components subject to an AMR. The staff stated that since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effect of loss of material and crack initiation and growth. Tables in Sections 3.2, 3.3 and 3.4 do not address these aging effects for closure bolting in these systems. The staff requested the applicant to identify the AMR results for closure bolting, or to provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

*3.4.10.1 Aging Effects*

The applicant indicated that non-Class 1 mechanical components within the scope of license renewal contain bolted closures that are necessary for the pressure boundary of the component. Examples of these bolted closures are valve bonnet to body closures, pump cover to casing closures, heat exchanger manway and end-bell closures, and piping flange sets. The bolted closure is comprised of two mating surfaces, a gasket, and a fastener set of studs or bolts and nuts. By themselves, the mating set, gasket, and fastener set have no component intended function. Together, the bolted closure forms an integral part of the pressure retaining boundary of the component. Gaskets are not relied upon for pressure boundary of the bolted closure, in accordance with the design codes, and are not subject to an AMR.

Bolted closures are exposed to two environments. The mating surfaces are exposed internally to the process fluid, while the external surfaces and the fastener set are exposed to the ambient environment where the bolted closures are located. Aging effects for external and internal surfaces of the mating set of bolted closures are the same as other components in the system made from the same material and exposed to the same environment. Programs for the system (i.e., Chemistry Control Program and Fluid Leak Management Program) containing the bolted closure are applicable to the mating set and are not discussed here further.

The aging effects for the fastener set of non-Class 1 bolted closures are loss of material of carbon and low-alloy steel, and cracking of carbon, low-alloy, and stainless steels. Loss of material of the fastener set of the bolted closure may occur as a result of fluid leakage, use of an improper lubricant during assembly, or exposure to the ambient environment. Cracking of the fastener set of bolted closures may occur as a result of improper material selection, improper torquing during assembly, use of an improper lubricant, fluid leakage, or exposure to the ambient environment. Of these aging effects, the applicant determined the following are the aging effects requiring management for carbon and low-alloy steel fastener sets:

- loss of material of the fastener set due to boric acid exposure
- loss of material of the fastener set in systems with operating temperatures below ambient conditions that result in condensation
- loss of material of the fastener set in the yard environment that are repeatedly wetted and dried from exposure to the elements

The applicant stated that no aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

On the basis of its review of the RAI response pertaining to non-Class 1 bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments identified.

*3.4.10.2 Aging Management Programs*

The applicant indicated that the Fluid Leak Management Program will manage loss of material of Non-Class 1 bolted closures in the reactor and auxiliary buildings due to leakage from systems containing boric acid. No systems containing boric acid are located outside these two buildings. The Fluid Leak Management Program is described in LRA Appendix B, Section B.3.15.

The Inspection Program for Civil Engineering Structures and Components will manage loss of material of non-Class 1 bolted closures in systems with operating temperatures below the surrounding ambient environment that are wet with condensation. In addition, this program will also manage loss of material of non-Class 1 bolted closures located in the yard that are repeatedly wetted and dried from exposure to the elements. The Inspection Program for Civil Engineering Structures and Components is described in LRA Appendix B, Section B.3.21.

The Fluid Leak Management Program and the Inspection Program for Civil Engineering Structures are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for non-Class 1 closure bolting. The staff’s evaluation of these AMPs is documented in Section 3.0 of this SER.

*3.4.10.3 Conclusions*

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the closure bolting in mechanical systems, as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with non-Class 1 closure bolts will be adequately managed, so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.5 Aging Management of Containments, Structures, and Component Supports

In LRA Section 2.1, "Scoping and Screening Methodology," the applicant described the method used to identify the structures and components (SCs) that are within the scope of license renewal and subject to an AMR. The applicant identified and listed the structures in LRA Section 2.4, "Scoping and Screening Results: Structures." The staff's evaluation of the scoping methodology and the structures included within the scope of license renewal, and subject to an AMR, is documented in Sections 2.1 and 2.4 of this SER, respectively.

Section 3.5 of the LRA defined the external and internal environments applicable to the containments, structures and component supports as follows—

- Below-grade — Below-grade portions of structures are exposed to back fill and groundwater. The groundwater at McGuire and Catawba is not aggressive. The McGuire groundwater pH ranges between 8.1 and 8.4; the chloride concentration is less than 20 ppm; and the sulfate concentration is less than 30 ppm. The Catawba groundwater pH ranges between 5.7 and 7.0; the chloride concentration is less than 25 ppm; and the sulfate concentration is less than 35 ppm.
- Borated Water — Borated water is demineralized water treated with boric acid.
- Concrete — Steel components located in concrete are protected by the alkaline environment of the concrete.
- External — External surfaces of structures are exposed to the external ambient environment.
- Ice Condenser Environment — The normal operating atmosphere in the ice condenser is at 10°F to 20°F and the absolute humidity is very low.
- Raw Water — Raw water is water from a lake, pond, or river that has been rough-filtered and possibly treated with a biocide.
- 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.
- Sheltered environment — The ambient conditions within the sheltered environment may or may not be controlled. The sheltered environment atmosphere is a moist air environment. Components in systems with external surface temperatures the same or higher than ambient conditions due to normal system operation are expected to be dry.

In Appendix A of the LRA, "Updated Final Safety Analysis Report (UFSAR) Supplement," the applicant provided a summary description of the programs and activities used to manage the effects of aging, as required in 10 CFR 54.21(d). The applicant provided a more detailed description of these AMPs for the staff to use in its evaluation in Appendix B to the LRA. In LRA Appendix D, the applicant states that no changes to the McGuire and Catawba TS have been identified. A discussion of the AMR results for each structure and structural component follows.

### 3.5.1 Reactor Building

#### *3.5.1.1 Technical Information in the Application*

The aging management review results for the reactor buildings, including the concrete shield building, the steel containment, the ice condenser components and all of the reactor building interior structural components, except component supports, are presented in Table 3.5-1 of the LRA. Table 3.5-1 of the LRA identifies the components that constitute the reactor building along with the component (1) function, (2) material, (3) environment, (4) aging effects, and (5) AMPs and activities.

Section 2.4.1 of the LRA states that the concrete shield building (or reactor building) structure is part of the containment system, which is designed to ensure that an acceptable upper limit of leakage of radioactive material is not exceeded under design basis events. The reactor building is a seismic Category I structure at both the McGuire and Catawba Nuclear Stations. Each reactor building is a reinforced concrete structure composed of a right cylinder with a shallow dome and flat circular foundation. The reactor building houses the steel containment vessel and is designed to provide biological shielding as well as missile protection for the steel containment vessel. The materials of construction for the concrete shield building, as shown in Table 3.5-1 of the LRA, are primarily concrete and include the dome, foundation mat, and shell wall. LRA Table 3.5-1 also identifies the steel foundation dowels as an in-scope component for the McGuire nuclear station concrete shield building. The concrete shield building components are exposed to (1) external, (2) reactor building, and (3) below-grade environments. The McGuire nuclear station foundation dowels are enclosed in concrete.

Section 2.4.1 of the LRA states that the steel containment surrounds the RCS and functions as the primary containment. The steel containment is a freestanding, welded seismic Category I steel structure with a vertical cylinder, hemispherical dome, and a flat base. The steel containment shell is anchored to the concrete shield building foundation by means of anchor bolts around the circumference of the cylinder base. The base of the containment is a liner plate encased in concrete and anchored to the concrete shield building foundation. The materials of construction for the steel containment, as shown in Table 3.5-1 of the LRA, are either carbon steel or stainless steel and include the (1) steel containment vessel, (2) mechanical, electrical, and fuel transfer tube penetrations, (3) equipment hatch, (4) personnel air locks, and (5) bellows. Each of the steel containment components is exposed to an internal (reactor building) environment.

The ice condenser structural components are part of the reactor building internal structures. The materials of construction for the ice condenser components, as shown in Table 3.5-1 of the LRA, are carbon steel, galvanized steel, and concrete and include the (1) ice baskets, (2) lattice frames and support columns, (3) doors, (4) lower support structure, and (5) wear slab. Each of the ice condenser components is exposed to an internal (ice condenser or reactor building) environment.

Section 2.4.1 of the LRA states that the reactor building internal structures consist of a variety of reinforced concrete and structural steel structures. The internal structures enclose the RCS and provide biological shielding and pressure boundaries for the lower, intermediate, and upper volumes of the containment interior. These structures also provide support and restraint for all major equipment, components, and systems located within the reactor building. The internal structures are supported on the concrete reactor building foundation. The materials of construction for the reactor building interior structural components, as shown in Table 3.5-1 of the LRA, are carbon steel, stainless steel, and concrete and include anchorages, embedments, equipment pads, flood curbs, hatches, shields, floor slabs, walls, beams, and columns. The pressure seals and gaskets used in the reactor building are made of ethylene propylene dienyl monomer (EPDM). The reactor building internal structural components are exposed to internal (reactor building) and external (equipment hatch missile shield) environments. The anchorages and embedments are encased within concrete.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function (e.g., the annulus). The applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions as potential aging effects. The applicant also provided the Ventilation Area Pressure Boundary Sealants Inspection, which it credited to monitor these aging effects.

3.5.1.1.1 Aging Effects

Table 3.5-1 of the LRA identifies the following applicable aging effects for components that constitute the reactor building:

- change in material properties for concrete components in the concrete shield building that are exposed to an external environment
- loss of material of carbon steel components exposed to an internal (reactor building, ice condenser) environment
- cracking of stainless steel penetration bellows in the reactor building
- loss of material of the galvanized steel ice baskets in the ice condenser
- cracking and change in material properties for the EPDM pressure seals and gaskets in the reactor building

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

3.5.1.1.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following AMPs with managing the identified aging effects for the components that constitute the reactor building:

- Cntainment Leak Rate Testing Program
- Containment ISI Plan — IWE
- Ice Condenser Inspections
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Divider Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building will be adequately managed by these AMPs during the period of extended operation.

*3.5.1.2 Staff Evaluation*

In addition to LRA Section 3.5, the staff reviewed the pertinent information provided in LRA Section 2.4, “Scoping and Screening Results: Structures,” and the applicable aging management program descriptions provided in LRA Appendix B to determine whether the aging effects for the reactor building structural members have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s AMPs credited for the aging management of the reactor building structural members at McGuire and Catawba nuclear stations. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the reactor building structural members.

3.5.1.2.1 Aging Effects

Table 3.5-1 of the LRA provides an aging management review of the reactor building structural components. Table 3.5-1 of the LRA is divided into the following four sections: (1) concrete shield building, (2) steel containment, (3) ice condenser components, and (4) reactor building interior structural components. The staff’s evaluation of the applicant’s aging management review for these components follows.

<u>Concrete</u>: The applicant identified change in material properties as the only applicable aging effect for the concrete dome and shell wall of the concrete shield building. These two components are exposed to an external environment. No aging effects are identified in LRA Table 3.5-1 for the other concrete components of the reactor building. The other concrete components of the reactor building are exposed to internal (reactor building, ice condenser) and below-grade environments.

In addition to change in material properties, the staff considers cracking and loss of material to be both plausible and applicable aging effects for the concrete components of the reactor building that are exposed to either internal (reactor building, ice condenser) or external (outdoor) environments. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that concrete SCs need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation depending on the stresses and strains due to normal and incidental loadings, as well as the environment, to which they are subjected. Concrete SCs subjected to sustained loading, such as crane or monorail operation, and/or sustained adverse environmental conditions, such as high temperatures, humidity, or chlorides, will degrade, thereby potentially affecting the intended function(s) of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects accentuate. On the basis of industry-wide evidence, the American Concrete Institute (ACI) has published a number of documents (e.g., ACI 201.1R, “Guide for Making a Condition Survey of Concrete,” ACI 224.1R, “Causes, Evaluation and Repairs of Cracks in Concrete Structures,” and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures") that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent characteristics of concrete structures to degrade with time, if not properly managed. Similar observations of concrete aging, made by NRC staff, are detailed in NUREG-1522, "Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures." As such, by letter dated January 28, 2002, the staff requested, in RAI 3.5-7, that the applicant identify the aging management program(s) that will be used to manage the aging effects for the above-grade concrete components listed in Tables 3.5-1 and 3.5-2 of the LRA.

In its response dated March 11, 2002, the applicant stated:

> Duke Power disagrees with the NRC staff position. The standards and results of NUREG-1522 inspections do not draw one to conclude that aging is an inherent characteristic of concrete, if not properly managed. Most of the industry-wide experience associated with the degradation of concrete in the standards is the result of exposure to severe environments such as marine or chloride exposure. Most, if not, all of the pictures in ACI 201.1R, "Guide for Making a Condition Survey of Concrete," depict degradation of bridges exposed to salt attack. In these environments, condition monitoring activities are appropriate.
>
> In contrast, the NRC staff fails to reference standards or reports that support the inherent durability of concrete. ACI 201.2R, "Guide to Durable Concrete," states that "durable concrete will retain its original form, quality, and serviceability when exposed to its environment." It goes on to state that "concrete will perform satisfactorily when exposed to various atmospheric conditions, to most waters and soils containing aggressive chemicals, and to many other kinds of chemical exposure."
>
> In addition, NUREG/CR-6424, "Report on Aging of Nuclear Power Plant Reinforced Concrete Structures," reports that most instances related to degradation of concrete structures in the United States occurred early in the life of the structures and have been corrected. Causes were primarily related either to improper material selection, construction/design deficiencies, or environmental effects. Examples of some of the problems attributed to these deficiencies include concrete cracking, concrete voids or honeycombing, and concrete compressive strength values that were low relative to design values at a specific concrete age. In almost all cases, the concrete cracks were considered to be structurally insignificant or easily repaired using techniques such as epoxy injection. The voids and honeycombed areas and low-strength concrete areas were repaired or replaced. Quality control/quality assurance programs at nuclear power plants generally have been very effective in ensuring that the basic factors related to the production of durable concrete are adequately addressed.
>
> NUREG/CR-4652, "Concrete Component Aging and Its Significance Relative to Life Extension of Nuclear Power Plants," contains additional information to support the durability of concrete structures. NUREG/CR-4652 contains a summary of the degradation associated with nuclear power plant structures. Although the vast majority of the problems detected did not present a threat to public safety or jeopardize the structural integrity of the particular component, five incidences were identified that if not discovered and repaired could potentially had have [sic] serious consequences. These incidences were all related to the concrete containment and involved two dome delaminations, voids under tendon bearing plates, anchor head failures, and a breakdown in quality control and construction management. These few incidences where the structural integrity of the component was jeopardized were attributed to design, construction, or human errors, but not to aging. These findings are also reported in SECY 96-080 as the basis for the revision to 10 CFR 50.55(a) to incorporate inspections in accordance with ASME Subsection IWL.
>
> NUREG/CR-4652 concludes that the results of the study are considered to be sufficiently representative that some general observations can be made on concrete aging and component performance. When concrete is fabricated with close attention to the factors required for durable concrete, the concrete will have infinite durability unless subjected to extreme external influences (overload, elevated temperatures, industrial liquids, etc.). Under normal environmental conditions aging of concrete does not have a detrimental effect on its strength for concrete ages to at least 50

years. [Note: 50 years is the limit on age for which well-documented data has been identified. The number of concrete structures in existence having ages of 40 to 70 years, with a few in service for thousands of years, indicates that this value is conservative. Also, many structures continue to meet their function and performance requirements even when conditions are far from ideal.] The overall performance of concrete components in nuclear applications has been very good. With the exception of the anchor head failures at Farley 2, errors detected during the construction phase or early in the structure's life were of no structural significance or "easily" repaired and were non-aging related.

Many of the previously discussed documents were completed prior to 1990. More recent concrete inspection findings are documented in NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures," and NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants." These documents identify concrete cracking in various structures at several nuclear plant sites. The documents do not discuss the severity or impact of the cracking on the functional capabilities of the component. All cracks do not necessarily result in loss of the intended function. For example, ACI 349.3R provides guidance on the size of cracks which would be judged to be acceptable. Furthermore, the pictures in NUREG-1522 do not depict cracking that would result in loss of intended function of the concrete component or structure. The findings do support the need for concrete inspections in certain structures which are exposed to environments that may result in aging such as salt water, brackish water, etc. Duke agrees with this position as evidenced by the information in the Application. For example, loss of material and cracking are identified as aging effects in Table 3.5-2 for reinforced concrete beams, columns, and walls that are exposed to a raw water environment. The findings do not support the need for inspections of all concrete structures in all environments.

The aging management review for the identified concrete components was conducted in accordance with the guidance provided in NEI 95-10, which was endorsed by the NRC, and incorporates findings from NUREG-1557, NUREG-1522, NUREG/CR-6424, NUREG/CR-4652, and ACI standards. Based on the material/environment combinations, it was determined that no aging effects would occur for these components that would result in loss of the intended function for the period of extended operation. Therefore, no aging management programs are required.

The applicant stated in its response to RAI 3.5-7 that the severity of the age-related degradations to concrete nuclear structures, observed by the staff and industry, would not result, for most cases, in loss of intended function for these concrete components. Therefore, only concrete nuclear components and structures that are exposed to harsh or extreme environments, which would result in rapid aging, need aging management during the period of extended operation. The applicant cited the sound material design and construction of concrete components as the primary factor in its durability and resistance to aging.

The staff takes exception to the applicant's claim that aging management of concrete components via periodic inspections is necessary only for concrete SCs that are exposed to harsh environments. Both the operating and environmental conditions as well as the aging of concrete nuclear components are subject to change throughout the period of extended operation and, thus, applicants need to periodically inspect these components. ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," is a report that represents a consensus of knowledgeable individuals from the nuclear industry, consultants, and regulators. As stated in ACI 349.3R, sound engineering practices during material (concrete mix) design and construction together with sound inspection programs, in which the performance and condition are periodically evaluated and monitored, are <u>both</u> necessary to maintain the serviceability of concrete nuclear structures. Periodic visual inspections (1) can provide significant quantitative and qualitative data regarding structural performance and extent of degradation, (2) are vital to monitor the effects of operating and environmental conditions, and (3) enable the timely identification and correction of degraded conditions.

The staff recognizes that the applicant has performed an aging management review by 10 CFR 54.21(a)(3) for each structure and component that was determined to be in the scope of license renewal. The staff position regarding the aging management reviews of concrete components performed by license renewal applicants is that they should be used to differentiate between those components requiring only periodic inspections and those requiring further evaluation, as documented in interim staff guidance issued on April 5, 2002 (ADAMS Accession No. ML020980194). Aging management review results of concrete structures and components may also be used to establish different scheduled inspection frequencies, similar to those recommended by ACI 349.3R, for AMPs.

In conclusion, periodic inspections of concrete components during the period of extended operation are necessary in order for the staff to make a reasonable assurance finding that in-scope concrete structures and components will maintain their structural integrity and intended function(s). Periodic visual inspections of concrete nuclear structures are a vital part of the license renewal program. On this basis, the staff disputed the applicant's claim, in response to RAI 3.5-7, that AMPs are necessary only for the above-grade concrete components, listed in Tables 3.5-1 and 3.5-2 of the LRA, that are exposed to harsh environments. This issue was characterized as SER open item 3.5-1.

On September 18, 2002, the staff met with the applicant to discuss this and other SER open items. The meeting is summarized by memorandum dated November 18, 2002. In a letter dated October 2, 2002, the applicant agreed to resolve open item 3.5-1 by committing to manage the aging of accessible concrete structural components during the period of extended operation. In electronic correspondence dated October 10, 2002 (ADAMS Accession No. ML023290464), the staff indicated that a more detailed response to the SER open item would be needed to resolve this open item and submitted the following request to the applicant:

> Please submit revised AMR results tables for all of Section 3.5, which should also include and clearly reference the concrete structures/components in the SBO recovery path that were brought into scope and for which no aging effects were identified. The revised tables must indicate the aging effect(s) for each structure or component as well as the AMP(s) credited.

To show the specific concrete components that will be managed, the applicant subsequently submitted revised AMR results tables for Section 3.5 of its LRA; these revised tables were submitted by letter dated October 28, 2002. In this letter, the applicant referenced Note 4 in the column for aging effects for each accessible concrete item in Tables 3.5-1 and 3.5-2. However, Note 4 did not specify the aging effects that would be managed during the period of extended operation. In a letter dated November 14, 2002, the applicant provided a revised Note 4, in which it committed to manage loss of material, cracking, and change in material properties for the accessible concrete components identified in Tables 3.5-1 and 3.5-2 of the LRA. Note 4, as revised by the applicant, states:

> Duke did not identify any aging effects that would result in loss of component intended function. The staff in its SER dated August 14, 2002 identified loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components. Notwithstanding the disagreement on the aging effects that require management for the period of extended operation, Duke committed, in its response to Open Items 3.5-1 and 3.5-3 provided in a letter dated October 2, 2002, to perform periodic inspections of these concrete components to manage the aging effects of loss material, cracking, and change in material properties using the *Inspection Program for Civil Engineering Structures and Components*.

The applicant's commitment to periodically inspect accessible concrete structures and components through its Inspection Program for Civil Engineering Structures and Components is acceptable to the staff. Therefore, open item 3.5-1 is closed.

For below-grade concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is non-aggressive. By letter dated January 28, 2002, the staff requested, In RAI 3.5-1, that the applicant provide further information regarding the chemistry of the groundwater samples taken at both Catawba and McGuire nuclear stations. In addition, the staff requested that the applicant provide the frequency for future groundwater sampling in order to demonstrate that the condition of the below-grade environment for concrete components remains non-aggressive during the period of extended operation. In its response dated March 11, 2002, the applicant stated:

> The environmental parameters of the below-grade environment are discussed in Section 3.5.1 of the Application. Minimum degradation threshold limits for concrete have been established at 500 ppm chloride, 1,500 ppm sulfates, pH < 5.5 [Reference NUREG-1611]. The Catawba and McGuire groundwater parameters are below the limits where potential degradation of the concrete may occur. The environmental data for Catawba and McGuire is based on historical data during construction and data from more recent tests. The data spans more than 20 years. More than 20 years of environmental monitoring is sufficient to identify any trends toward aggressive environments; therefore, future tests of groundwater chemistry are not required. The SOC for the original license renewal rule supports the use of more than 20 years of operational data as sufficient. The NRC believes that the history of operation over the minimum 20-year period provides a licensee with substantial amounts of information and would disclose any plant-specific concerns with regard to age-related degradation.

During the NRC Scoping and Screening Inspection (conducted March 18-22, 2002, and documented in NRC Inspection Report 50-369/02-05, 50-369/02-05, 50-413/02-05, and 50-414/02-05), the applicant provided data from Lake Norman, adjacent to McGuire, and Lake Wylie, adjacent to Catawba, showing pH values and phosphate, chloride, and sulphate contents (ML021090060). The lake water sampling dates are from 1962 to 1996 for McGuire (Lake Norman) and from 1971 to 1996 for Catawba (Lake Wylie). In addition, the applicant referred the staff to the Environmental Reports (ERs) associated with the original construction of Catawba and McGuire. The ERs contain water table contour maps (ER Figure 2.4.4-2 for Catawba, and ER Figure 2.5.2-2, Revision 2, for McGuire).

As stated in the applicant's response to RAI 3.5-1, the chloride, sulfate, and pH values over the past 20 to 30 years are well below the limits where potential degradation of concrete may occur. As such, the applicant did not believe a commitment to periodically monitor the groundwater chemistry during the period of extended operation is warranted. In addition, the water contour tables for both Catawba and McGuire show that the water table levels decrease from the two nuclear stations outward to the surrounding areas. This implies that only a chemical event at the nuclear stations would potentially impact their respective site environments, including the groundwater. On the basis of the water sampling data from the two sites and outwardly sloping water contour tables, the staff concurs with the applicant that periodic monitoring of the groundwater during the period of extended operation is unnecessary. However, in its response to RAI 3.5-1, the applicant did not commit to initiate corrective action in the event of a potential change to the site environment resulting from a chemical release during the period of extended operation. Such a corrective action would need to include a commitment to monitor the groundwater chemistry and to assess the potential impact of any changes to the groundwater chemistry on below-grade concrete components. Therefore, the applicant's response to RAI 3.5-1 was initially considered by the staff to be inadequate, and this issue was characterized as SER open item 3.5-2.

In its July 9, 2002, response to the staff's potential open items letter, the applicant responded to this issue, which was characterized as RAI 3.5-1 (open item). The applicant stated that it did not commit to initiate a corrective action in the event of a potential change to the site environment, resulting from a chemical release during the period of extended operation, because such an event was not postulated. The applicant stated:

> It is simply not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Catawba or McGuire. Change in the environment due to a chemical release would be an abnormal event.

As stated in NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," aging effects from abnormal events need not be postulated specifically for license renewal. After the SER was issued with this identified as open item 3.5-2, the staff reviewed the guidance provided in NUREG-1800 and reconsidered the applicant's assertion that a potential change to the site environment resulting from a chemical release during the period of extended operation would be an abnormal event. The staff agreed that such a chemical release would not need to be postulated for the purposes of performing an aging management review for license renewal. Therefore, the staff closed open item 3.5-2 without any further information from the applicant. The applicant was notified of this resolution by electronic correspondence dated September 3, 2002 (ADAMS Accession No. ML023300155).

In addition to the below-grade concrete components in the reactor building, Table 3.5-1 of the LRA also does not identify any applicable aging effects for normally inaccessible concrete components such as the ice condenser wear slab. By letter dated January 28, 2002, the staff requested, in RAI 3.5-6, that the applicant describe its aging management review of inaccessible reactor building concrete components in further detail. In its response dated March 11, 2002, the applicant stated that the following areas of the reactor building are inaccessible due to the layout of the ice condenser system:

- wear slab that is located beneath a protective layer of ice
- structural concrete floor located beneath the wear slab
- surface of the crane wall that is located behind the insulated wall panels

The applicant, in its response to RAI 3.5-6, stated that these concrete components are designed in accordance with ACI and American Society for Testing and Materials (ASTM) standards, which provide for a good quality, dense, low-permeability concrete that provides resistance to aggressive chemical attack and corrosion of rebar. The applicant also stated that the concrete located in the ice condenser is exposed to a unique environment. The normal atmosphere in the ice condenser is low temperature (10 °F to 20 °F) and very low humidity. Under these operating and environmental conditions, and considering the quality of the concrete, the applicant stated that the above concrete components would not be subject to aging effects requiring management.

Regarding the ice condenser wear slab, the applicant stated that the wear slab is constructed of dense, low-permeability concrete and is protected by a coating as well as a layer of ice. The protective coating and layer of ice protect the wear slab from flowing water potentially arising from ice condenser wall panel defrosting. The applicant stated that during maintenance at either McGuire or Catawba, ice condenser wall panel defrosting is not a normal maintenance practice.

Regarding the structural concrete floor, which is located beneath the ice condenser wear slab, the applicant stated that a layer of foam concrete is located between the wear slab and the structural concrete floor to provide a layer of insulation. A vapor barrier is provided between the foam concrete and the structural concrete floor. The applicant also stated in response to RAI 3.5-6 that the structural concrete floor is accessible from below.

Regarding the crane wall, the applicant stated, in its response to RAI 3.5-6, that the interior surface of the crane wall is open to the reactor building environment and is accessible for inspection. However, the exterior surface of the crane wall is covered by wall panels in the ice condenser. Cooling ducts are incorporated into the wall panels to provide flow from the air handlers in the duct adjacent to the ice bed and return flow in the outer duct of the panel. The applicant stated that while the wall panels and cooling ducts make the exterior surface of the crane wall inaccessible for inspection, they also protect the crane wall from potential defrosting water.

Since these three normally inaccessible ice condenser concrete components are in a unique environment of low humidity and temperature, the staff acknowledges that there are no accessible concrete components in a similar environment that the applicant could use as an indicator of the aging of these inaccessible ice condenser components. However, portions of both the structural concrete floor, which is located beneath the ice condenser wear slab, and the crane wall are accessible for inspection. The applicant stated, in its response to RAI 3.5-6, that the structural concrete floor is accessible from below and that the interior surface of the crane wall is open to the reactor building environment and is accessible for inspection. Based on the reasoning stated above in RAI 3.5-7 concerning the aging management for accessible concrete components, the staff considered the applicant’s response to RAI 3.5-6 to be inadequate with regard to the structural concrete floor, which is located beneath the ice condenser wear slab, and the crane wall. For the ice condenser wear slab, the staff acknowledges that the slab is located beneath a layer of ice and that the slab also has a protective coating. The wear slab is also on top of the structural concrete floor and is therefore completely inaccessible for inspection. The staff believed that, in the event of an ice condenser wall panel defrosting, the wear slab would be accessible for inspection and should be inspected for signs of degradation; however, the staff subsequently realized that it had misinterpreted the applicant’s response to RAI 3.5-6 and, after the SER with open items was issued, acknowledged that the wear slab would be inaccessible even if the wall panel had defrosted. Nonetheless, the staff considered the applicant’s response to RAI 3.5-6, with respect to the crane wall and the structural concrete floor, to be inadequate. This issue was characterized as open item 3.5-3.

In its response to open item 3.5-3, dated October 2, 2002, the applicant stated the following:

> The Duke response to Open Item 3.5-3 is provided in two parts: the first part concerns the ice condenser wear slab and the second part concerns the ice condenser crane wall and accessible portions of the ice condenser structural floor.

> With respect to the ice condenser wear slab, Duke has performed an additional review of the design of McGuire and Catawba and determined that the ice condense wear slab is not within the scope of license renewal because it does not perform a license renewal function. The ice condenser slab is described in each station's UFSAR (Section 6.2.2 for McGuire and Section 6.7.1 for Catawba) as follows:
>
> > The wear slab is a concrete structure whose function is to provide a cooled surface as well as to provide personnel access support for maintenance and/or inspection. The wear slab also serves to contain the floor cooling piping.
>
> Therefore, no further aging management review of the ice condenser wear slab is required for license renewal.
>
> With respect to the accessible portions of the ice condenser crane wall and accessible portions of the ice condenser structural concrete floor, Duke disagrees with the staff conclusion that these structural components require aging management for the period of extended operation for the same reasons that Duke provided in its March 11, 2002 response to RAI 3.5-6 and the response to Open Item 3.5-1 provided above.
>
> Nevertheless and as a practical matter in order to support the timely resolution of this open item and the completion of the license renewal review on schedule, Duke will not challenge this issue further. Periodic inspections of the accessible portions of the crane wall and ice condenser structural concrete floor will be performed during the period of extended operation as part of the Inspection Program for Civil Engineering Structures and Components. No revisions to the UFSAR Supplement for either McGuire or Catawba is [sic] required in response to Open Item 3.5-3.

Since the ice condenser wear slab does not perform an intended function that meets the license renewal scoping criteria specified in 10 CFR 54.4, the staff agrees with the applicant's finding that the wear slab should not have been included within the scope of license renewal. The staff's review of this item is documented in Section 2.4.1.3.2 of this SER. In addition, since the applicant has committed to manage the aging effects for the accessible portions of the crane wall and ice condenser structural concrete floor during the period of extended operation (as indicated in its response to SER open item 3.5-1), the staff considers open item 3.5-3 to be closed.

<u>Steel</u>: Table 3.5-1 of the LRA identifies (1) loss of material of carbon steel components exposed to an internal (reactor building, ice condenser) environment, (2) loss of material of the galvanized ice baskets in the ice condenser, and (3) cracking of the stainless steel penetration bellows in the reactor building as applicable aging effects for the steel components in the reactor building.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components of the reactor building. However, the staff noted that no aging effects are identified in LRA Table 3.5-1 for the stainless steel fuel transfer canal liner plate, sump liner, and sump screens. These three stainless steel components are exposed to an internal (reactor building) environment as are the stainless steel penetration bellows, for which the applicant identified cracking as an applicable aging effect. In view of this discrepancy, by letter dated January 28, 2002, the staff requested, in RAI 3.5-4, that the applicant explain why cracking is not identified as an applicable aging effect for all stainless steel components in the reactor building. In its response dated March 11, 2002, the applicant stated that its aging management review for stainless steel components in the reactor building environment did not identify any applicable aging effects for the fuel transfer canal liner plate, sump liner, and sump screens. The applicant's aging management review included a review of its own operating experience as well as industry experience regarding these three stainless steel components. However, operating experience for the penetration bellows did reveal cracking due to stress corrosion cracking from chloride concentration and leaking as an applicable aging effect.

On June 7, 2002, the staff and applicant discussed this response to RAI 3.5-4 during a conference call, which was summarized in a memorandum dated June 7, 2002 (ML021620496). During the conference call, the applicant indicated that a leaking bellows had been identified in 1993 and was replaced in 1994. In 1997, leakage from the replacement bellows was identified, and the leaking bellows was replaced. A root cause determination attributed the 1997 bellows leak to transgranular stress corrosion cracking (TGSCC) as a result of exposure to or contact with chlorine. The applicant could not determine the source of chlorine and speculated that the contaminant could have been introduced by a surface brightener during the manufacturing process. The applicant further stated that TGSCC had not been listed as an applicable aging effect for the other components (fuel transfer canal liner plate, sump liner, and sump screens) because the normal operating environment would not expose these components to chlorine and they essentially consist of plate material that had not been polished or brightened by the manufacturer.

The staff finds the applicant’s explanation of why cracking caused by TGSCC was not identified as an applicable aging effect for fuel transfer canal liner plate, sump liner, and sump screens reasonable. By letter from the applicant dated July 9, 2002, this explanation was provided in official correspondence. Therefore, this issue is resolved.

The staff noted that Table 3.5-1 of the LRA does not distinguish between accessible and inaccessible carbon steel components in the reactor building. The applicant identifies loss of material as an applicable aging effect for all of the carbon steel components in the reactor building. However, the staff noted that the applicant does not describe how it will manage the aging of the inaccessible areas of the steel liner plate and other interior structural steel components. By letter dated January 28, 2002, the staff requested, in RAI 3.5-3, that the applicant address how the potential aging effect of loss of material will be managed for inaccessible areas. In its response dated March 11, 2002, the applicant stated its aging management review of steel reactor building components did not ignore any environmental conditions to which structures and components are exposed, including those conditions in areas that may turn out to be inaccessible for inspection. The applicant further stated that structures and components that are inaccessible may be exposed to unique environments because of their location. However, the applicant stated that its aging management review of the inaccessible portion of the steel components in the reactor building did not identify any inaccessible environments that result in aging effects different from those in the accessible environments. As such, no unique AMPs were determined by the applicant to be necessary for any accessible areas. Therefore, the applicant will use the Containment ISI Plan — IWE aging management program to manage both the accessible and inaccessible portions of the steel components in the reactor building. Any evidence of aging in accessible areas will be used to provide guidance for aging effects in inaccessible areas. The staff finds the applicant’s response to RAI 3.5-3 acceptable because it is consistent with regulatory guidance and industry-wide aging management of accessible and inaccessible components.

In its response to RAIs 2.4.1-1 and 2.4.1-4, the applicant identified steel penetrations as being within the scope of license renewal and provided the AMR results for the staff’s review (see Section 2.4.1.1.2 of this SER). The applicant identified the reactor building as the environment for these steel penetrations and loss of material as the aging effect. The applicant credited the Inspection Program for Civil Engineering Structures and Components as the AMP. The staff finds the aging effects identified appropriate for the material and environment specified and concludes that the aging effects will be adequately managed by the AMP identified.

The staff finds that the applicant's approach for evaluating the applicable aging effects for the steel components in the reactor building to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effects for steel components in the reactor building.

Elastomers: Table 3.5-1 of the LRA identifies cracking and change in material properties for the EPDM pressure gaskets and seals in the reactor building. The staff concurs with applicant's identification of these two aging effects for elastomer material components in the reactor building. In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant for structural members of the annulus. The staff concurs with applicant's identification of these two aging effects for structural sealant, which is treated as a subcomponent of the structural members of the annulus.

3.5.1.2.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following AMPs with managing the identified aging effects for the components that constitute the reactor building:

- Containment Leak Rate Testing Program
- Containment ISI Plan — IWE
- Ice Condenser Inspections
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- Divider Barrier Seal Inspection and Testing Program
- Technical Specification SR 3.6.16.3 Visual Inspection

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

Of the above AMPs, the Containment Leak Rate Testing Program, Containment ISI Plan — IWE, Fluid Leak Management Program, Inspection Program for Civil Engineering Structures and Components, and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the structures that make up the reactor building. The staff's evaluation of common AMPs is documented in Section 3.0 of the SER. The staff's evaluation of the Ice Condenser Inspections, Divider Barrier Seal Inspection and Testing Program, and Technical Specification SR 3.6.16.3 Visual Inspection AMPs are given below.

Ice Condenser Inspections

The applicant described its Ice Condenser Inspections in Section B.3.18 of the LRA. The applicant credits two activities for managing the aging of the ice condenser systems. The Ice Basket Inspection is a TS surveillance that is credited with managing the loss of material of the ice baskets. The Ice Condenser Engineering Inspection is credited with managing the loss of material in the ice condenser upper plenum, lower plenum, and top blankets. The staff reviewed Section B.3.18 of LRA Appendix B to determine whether the applicant had 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).

The applicant credits the following two activities for managing the aging of the ice condenser systems:

- Ice Basket Inspection
- Ice Condenser Engineering Inspection

Loss of material of the ice condenser steel ice baskets has been identified as an aging effect requiring management for the period of extended operation. The functional integrity of the ice condenser ice baskets ensures the ice condenser will perform its intended safety function. The purpose of the Ice Basket Inspection is to manage aging effects for the period of extended operation. The Ice Basket Inspection is a visual inspection, condition monitoring program, which is a requirement of the Catawba and McGuire TS. Based on operating experience, the program has been effective in identifying deficiencies and other minor degradation (not aging related) and is capable of detecting and managing loss of material.

Loss of material due to corrosion of steel components in the ice condenser environment has been identified as an aging effect requiring management for the period of extended operation. The purpose of the Ice Condenser Engineering Inspection is to manage loss of material of the ice condenser upper plenum, lower plenum, and top deck blankets for the period of extended operation. The Ice Condenser Engineering Inspection is a visual inspection, condition monitoring program which the applicant is currently implementing as part of an engineering support program at McGuire and Catawba.

The staff's evaluation of the ice condenser 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 and/or TS. 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.

[Program Scope] The applicant defined the scope of the Ice Basket Inspection as including all of the ice baskets located in the ice condenser, while the scope of the Ice Condenser Engineering Inspection includes the ice condenser structural components in the upper plenum, lower plenum, and top deck blankets. Because the scope includes the structures and components that are subject to the aging effects, the staff finds the scope of the program to be acceptable.

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

[Parameters Inspected or Monitored]  The applicant identified the parameter monitored by the Ice Condenser Inspections as loss of material.  Because the visual inspections are capable of detecting degradation and loss of material of the ice condenser components, the staff finds the inspections to be acceptable.

[Detection of Aging Effects]  The Ice Basket Inspection uses visual examination of the ice baskets to detect the loss of material, and the Ice Condenser Engineering Inspection uses visual inspection of  the structural components in the upper plenum, lower plenum, and top deck blankets to detect loss of material.  The staff finds this approach to be consistent with current industry practice and agrees that it is an acceptable method of detecting aging before loss of function.

[Monitoring and Trending]  Section B.3.18 of LRA Appendix B describes the monitoring and trending.  The Ice Basket Inspection requires a visual inspection performed at a 40-month frequency in accordance with TSSR 3.6.12.6.  For both McGuire and Catawba, the sample includes two ice baskets from each of three azimuthal groups of bays.  The Ice Basket Inspection also requires a visual inspection every refueling outage of each basket that is replenished (emptied of ice and refilled) based on ice weight and sublimation history.  Records are maintained to permit confirmation of the inspection results, including any discrepancies identified, associated root cause determinations, and corrective actions taken.

The Ice Condenser Engineering Inspection consists of visual inspections every refueling outage of the structural components in the upper plenum, lower plenum, and top deck blankets. Records are maintained, and trending information is retained in files.

The baskets are monitored and maintained in accordance with the TS, and the structural components are monitored on a refueling outage frequency and trended.  The staff finds these activities acceptable.

[Acceptance Criteria]  The applicant described the acceptance criteria as no adverse conditions that could prevent the ice condenser from performing its intended function.  Acceptance criteria include no unacceptable visual indication of material condition including corrosion, glycol leaks, and missing or loose fasteners.  Because degradation is detectable by visual inspections and this approach is consistent with current industry practice, the acceptance criteria are acceptable to the staff.

[Operating Experience]  The applicant reported that a review of the Ice Basket Inspection conducted at McGuire and Catawba confirms the reasonableness and acceptability of the inspection frequency in that degradation of the ice basket is detected prior to loss of function. Identified deficiencies were associated primarily with missing screws and minor dents on the ice baskets.  These deficiencies were attributed to ice basket maintenance (i.e., weighing, replenishing ice, etc.) and were not age-related. Repairs were performed at the time of inspection under the guidance of site procedures.

The applicant reported that a review of previous Ice Condenser Engineering Inspections conducted at McGuire and Catawba confirms the reasonableness and acceptability of the inspection frequency in that degradation of ice condenser structural components is detected prior to loss of function. The applicant reported that the majority of work orders were generated for cosmetic repairs and removal of excess frost. The identified deficiencies were attributed to maintenance activities and were not age-related with the exception of minor rusting on blanket fasteners, which did not result in any loss of intended function.

On the basis of the operating experience and root causes identified for corrective work, the staff concludes that the aging management activities described above have been effective at maintaining the intended function of the ice condenser system and reasonably can be expected to do so through the period of extended operation.

FSAR Supplement: In Appendix A-1, Section 18.2.14, and Appendix A-2, Section 18.2.13, of the LRA, the applicant described the Ice Condenser Engineering Program for McGuire and Catawba, respectively. The staff reviewed this information and found it to be consistent with the information provided in the LRA. No FSAR supplement was provided for the Ice Basket Inspection because this activity is described in the TS. The staff finds the TS has sufficient information to be an acceptable summary description of the AMP.

In conclusion, the staff reviewed the information provided in Section B.3.18 of LRA Appendix B and the summary description in the FSAR supplement in LRA Appendix A. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with the ice condenser structures will be adequately managed such that there is reasonable assurance that the intended function will be maintained in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Divider Barrier Seal Inspection and Testing Program</u>

Section B.3.11 of LRA Appendix B provides the description of the divider barrier seal inspection and testing activities. The applicant credits these activities for managing the aging effects of cracking and change of material properties of the elastomeric seals in the divider barrier inside containment. The staff reviewed Section B.3.11 of LRA Appendix B to determine whether the applicant had demonstrated that divider barrier seal inspection and testing activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Section B.3.11 of LRA Appendix B describes the inspection and testing activities for the divider barrier seals. The divider barrier is the physical boundary that separates upper containment from lower containment. Several reactor building internal structures comprise the divider barrier and, as part of the divider barrier, elastomeric pressure seals are provided at locations where it is necessary to limit potential ice condenser bypass leakage. The purpose of the program is to manage the aging effects of cracking and change in material properties of the elastomeric seals for the period of extended operation. The program includes the following elastomeric seals:

- ice condenser seals
- control rod drive mechanism shield seals
- operating deck hatches and access opening seals
- pressurizer enclosure seals
- reactor coolant pump hatch seals
- steam generator enclosure seals

For both McGuire and Catawba, the inspections and testing are performed in accordance with TSSR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5.

The applicant concluded that the continued implementation of the Divider Barrier Seal Inspection and Testing Program will manage the identified aging effects such that the seals will continue to perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the Divider Barrier Seal Inspection and 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.

[Program Scope] The scope of the program includes the following elastomeric seals:

- ice condenser seals
- control rod drive mechanism shield seals
- operating deck hatches and access opening seals
- pressurizer enclosure seals
- reactor coolant pump hatch seals
- steam generator enclosure seals

The applicant has included all the seals in the scope of this program which are essential for ensuring the separation of upper containment from lower containment. The staff considers the scope 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.

[Parameters Monitored or Inspected] The program monitors for cracking and change in material properties of elastomeric pressure seals. As the elastomeric seal can crack or change its properties as a result of aging, sustained high temperatures, or radiation effects, the staff considers the parameters monitored or inspected reasonable and acceptable.

[Detection of Aging Effects]  Section B.3.11 of LRA Appendix B states that cracking and change in material properties of elastomeric seals are detected through visual examinations and coupon testing.  The inspections and testing are performed in accordance with Technical Specification SR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5.  Since cracking and change in material property can be detected by visual examination and coupon testing, and since the testing is in accordance with the TS, the staff finds this acceptable.

[Monitoring and Trending]  Section B.3.11 of LRA Appendix B provides the following information:

> The Divider Barrier Seal Inspection and Testing Program detects aging effects through visual examination of the seals and coupon testing.  The inspections and testing are implemented as required by McGuire and Catawba TS (SR) 3.6.14.2, 3.6.14.4 and 3.6.14.5.
>
> The ice condenser seals are visually inspected for the presence of holes, ruptures, abrasions, splice separation or gap, and changes in physical appearances such as discoloration, chemical attack, radiation damage, etc.  At least 95 percent of the ice condenser seal is inspected.  In addition, the seal mounting hardware is examined for looseness and loss of material due to corrosion.  Two seal coupons are removed and tested to verify the tensile strength of the material.  The frequency of the inspection of seals and tests of the coupons is once every 18 months as required by Technical Specification Surveillance Requirements 3.6.14.4 and 3.6.14.5.
>
> The remaining divider barrier seals are visually inspected for cracks, defects in the sealing surface, deterioration of the seal material, and detrimental misalignments.  The frequency of the inspection is prior to final closure after each opening and once every 10 years for resilient seals as required by Technical Specification Surveillance Requirement 3.6.14.2.

The monitoring and trending for inspection and testing of the seals are in accordance with the Technical Specification surveillance requirements.  The staff finds  the extent of examination included for monitoring and trending reasonable and acceptable.

[Acceptance Criteria]  Section B.3.11 of LRA Appendix B provides the following information:

> The acceptance criteria for the Divider Barrier Seal Inspection and Testing Program are specified in Technical Specification Surveillance Requirements 3.6.14.2, 3.6.14.4 and 3.6.14.5.  The minimum tensile strength of both test coupons is specified in Technical Specification 3.6.14.4.  The acceptance criteria for the visual inspection are no visual evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or change in physical appearance.  Divider barrier seal mounting hardware (i.e. bolts, nuts etc.) must be properly installed, with no unacceptable indication of corrosion.

The staff considers the acceptance criteria associated with this program reasonable and adequate.

[Operating Experience]  The operating experience at McGuire and Catawba has not identified any adverse aging conditions of the divider barrier seals, such as cracking or change in material properties.  Past coupon tests at both stations indicated tensile strength above that specified in SR 3.6.14.4, with sufficient margin.  The staff finds that the described operating experience indicates that the program will adequately monitor the aging of the divider barrier seals.

FSAR Supplement:  The essential requirements for this aging management program are stated in the Technical Specification Bases for SR 3.6.14.2, SR 3.6.14.4, and SR 3.6.14.5.  The applicant did not provide a description in the FSAR supplement, and the staff does not see a need for one.

In conclusion, the staff reviewed the information provided in Section B.3.11 of LRA Appendix B. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with divider barrier seals will be adequately managed, so 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).

Technical Specification SR 3.6.16.3 Visual Inspection

The applicant has identified change in material property due to leaching as an aging effect requiring programmatic management for the walls and dome of the concrete reactor building for the period of extended operation. The applicant credits the Technical Specification Surveillance Requirement (SR) 3.6.16.3 Visual Inspection program, discussed in Section B.3.33 of LRA Appendix B, with managing this aging effect. SR 3.6.16.3 requires that the applicant perform a visual inspection of the exposed interior and exterior surfaces of the reactor building three times every 10 years. The purpose of the visual inspections is to uncover evidence of deterioration which could affect the reactor building structural integrity. The staff reviewed Section B.3.33 of LRA Appendix B to determine whether the applicant had 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).

Section B.3.33 of LRA Appendix B provides a discussion of the program requirements for the Technical Specification SR 3.6.16.3 Visual Inspection. The purpose of the program is to manage the aging effect of leaching in the walls and dome of the concrete reactor building. SR 3.6.16.3 requires that the applicant perform a visual inspection of the exposed interior and exterior surfaces of the reactor building three times every 10 years to identify deterioration which could affect the reactor building structural integrity.

The staff's evaluation of the Technical Specification SR 3.6.16.3 Visual 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 TS. 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.

[Program Scope] The applicant described the scope of the Technical Specification SR 3.6.16.3 Visual Inspection as including the accessible surface areas of the walls and dome of the concrete reactor building. The staff finds the scope acceptable because it is comprehensive and includes the areas of the reactor building walls and dome appropriate to identify the aging effects.

[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, and the staff did not identify the need for any preventive actions.

[Parameters Monitored or Inspected]  The applicant identified the monitored parameter as the change in material property due to leaching.  The staff agrees that because the visual inspections can detect property changes due to leaching, this is a proper parameter to identify potential degradation.

[Detection of Aging Effects]  The applicant stated that the Technical Specification SR 3.6.16.3 Visual Inspection program uses visual examination techniques to detect change in material properties due to leaching prior to loss of the structure's intended function.  Because the inspections are current industry practice and have demonstrated the ability to detect changes, the staff finds that the inspection is capable of detecting the change and is acceptable.

[Monitoring and Trending]  Section B.3.33 of LRA Appendix B states that loss of material due to leaching will be detected through the visual examination conducted as a part of the SR 3.6.16.3.  This SR provides advance indication of deterioration of the concrete structural integrity of the reactor building.  The frequency of the inspection is three times every 10 years. SR 3.6.16.3 does not include a requirement to monitor or trend degradation.  If unacceptable conditions are noted in the inspection, the applicant performs further evaluation as appropriate.

By letter dated January 28, 2002, the staff requested, in RAI B.3.33-1, additional information related to the applicant's methods of inspecting the higher elevations of the reactor building.  In its response dated March 11, 2002, the applicant stated that the containment vessel stiffening rings, located at 10-foot intervals along the exterior of the steel containment vessel, act as a platform for the inspectors, and that ladders and binoculars are used to inspect the exterior of the reactor building walls.

The staff finds, based on a review of the application and the applicant's response to the staff's RAI, that the monitoring is capable of identifying potential problems before they can result in loss of intended function.  The staff did not identify a need for trending.

[Acceptance Criteria]  The applicant stated that the acceptance criteria are based on visual indication of structural damage or degradation.  For concrete, the acceptance criterion is no unacceptable indication of change in material property due to leaching.  The staff concludes that, because the inspection methods are capable of detecting deterioration, the acceptance criteria are appropriate.

[Operating Experience]  The applicant reported that the TSSR 3.6.16.3 Visual Inspections have been performed at the specified frequencies since initial operation at McGuire and Catawba, and the results are documented in station procedures.  The applicant further notes that the inspections have revealed only minor degradation of concrete at McGuire and Catawba. Observations include minor hairline surface cracking and minor leaching.  The applicant reported that leaching has been observed on the interior of the reactor building domes at McGuire near the dome-to-shell interface, and the applicant has planned maintenance for the dome exterior to minimize water intrusion.  Adverse conditions are reinspected by the applicant during subsequent inspections.  The applicant notes that the observed aging effects are relatively minor and have no impact on the ability of the concrete reactor building to perform its intended function.

By letter dated January 28, 2002, the staff requested, in RAI 3.5-2, the applicant to provide the extent of the degradation observed. In its response dated March 11, 2002, the applicant provided further information regarding the minor degradation discussed above. Previous inspections had revealed changes in material properties due to leaching on the shield building dome and near the dome-to-shell interface at McGuire. Subsequent inspection did not indicate any growth of the leaching or rebar corrosion. Rebar corrosion would be evidenced by rust stains, pop-outs, or spalling. The applicant further stated that the maintenance on the exterior of the shield building dome was completed in the fall of 2001. The domes were recoated with elastomeric urethane 18 inches up the parapet wall and 18 inches up the dome. The remainder of the dome was sealed with a clear concrete sealer. The applicant stated that subsequent inspections will determine whether the corrective actions are adequate and whether any additional maintenance is required. The staff finds the applicant's maintenance work and commitment to perform future inspections adequate and reasonable and, therefore, RAI 3.5-2 is resolved.

A review of the operating experience indicates that the inspections have been effective at identifying degradation and allowing the applicant to take corrective action. This provides reasonable assurance the inspections will continue to identify potential problems through the period of extended operation.

FSAR Supplement: The LRA does not provide a FSAR supplement for the Technical Specification SR 3.6.16.3 Visual Inspection program. Since it is an existing program that is adequately described in the TS, the staff finds this acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.33 of LRA Appendix B, the TS, and the applicant's March 11, 2002, responses to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that there is reasonable assurance that the aging effect of leaching of the concrete reactor building 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).

*3.5.1.3 Conclusions*

The staff reviewed the information in LRA Table 3.5.1, as well as the applicable aging management program descriptions in LRA Appendix B. On the basis of its review, and with the resolution of SER open items 3.5-1, 3.5-2, and 3.5-3, the staff finds that the applicant has demonstrated that the aging effects associated with the reactor building structural members will be adequately managed, so that there is reasonable assurance that these structural components 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).

### 3.5.2 Other Structures

*3.5.2.1 Technical Information in the Application*

The aging management review results for structures outside the reactor building are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA is divided into three sections covering (1) concrete structural components, (2) steel structural components, and (3) other structural components. In addition, Table 3.5-2 of the LRA identifies the components that constitute the other structures along with the component (1) function, (2) material, (3) environment, (4) aging effects, and (5) AMPs and activities.

The aging management review results for structural components located within the following structures are provided in Table 3.5-2 of the LRA:

- auxiliary building (including control building, diesel generator buildings, fuel buildings, groundwater drainage system, main steam doghouses, and the UHI tank building (Catawba only)
- condenser cooling water intake structure
- nuclear service water structures
- standby nuclear service water pond dam
- standby shutdown facility
- turbine buildings
- unit vent stack
- yard structures

The materials of construction for the components of the structures outside the reactor building, which are subject to aging management review, are (1) concrete, (2) steel, (3) boraflex, (4) silicone, (5) soil, (6) rubber, (7) masonry, (8) aluminum, and (9) a composite roofing material.

The components of the structures outside the reactor building are exposed to external, sheltered, below-grade, raw water, and borated water environments. In addition, the components in Table 3.5-2 of the LRA include steel anchorages, embedments, and foundation dowels encased in concrete.

In response to open item 2.5-1, the applicant provided, by letter dated June 26, 2002, AMR results for the passive, long-lived structures and components associated with the offsite power path. During a meeting with the applicant on September 18, 2002 (summarized in a memorandum dated November 18, 2002), the staff indicated that, since no aging effects were specified for concrete structures and components identified in the June 26, 2002, AMR results tables, these concrete structures and components (which the staff believed were subject to aging effects) were additional examples of open item 3.5-1. In subsequent electronic correspondence with the applicant dated October 10, 2002 (ADAMS Accession No. ML023290464), the staff requested that the applicant present revised AMR results tables from the LRA.

By letter dated October 28, 2002, the applicant submitted revised LRA Tables 3.5-1, 3.5-2, and 3.5-3 to indicate the additional passive, long-lived structures and components associated with the offsite power path that were brought into the scope of license renewal. The structural components included concrete equipment pads, foundations, trenches, and reinforced walls, columns, and floor slabs. Structural steel components included anchorages, checkered plates, embedments, expansion anchors, beams, columns, plates, and trusses.

In a letter dated November 14, 2002, the applicant submitted its response to SER open item 2.3-3 pertaining to the applicant's treatment of structural sealants (subcomponents of structural members) in certain ventilation system applications for which pressure boundary integrity was an intended function (e.g., the fuel handling building, the auxiliary building, and the control area). The applicant identified cracking and shrinkage of structural sealants due to exposure to ambient conditions as potential aging effects. The applicant also provided the Ventilation Area Pressure Boundary Sealants Inspection, which it credited to monitor these aging effects.

#### 3.5.2.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in structures outside the reactor building:

- cracking of concrete fire walls in a sheltered environment
- cracking and loss of material for concrete components exposed to raw water
- change in material properties for some concrete components exposed to an external evironment
- loss of material for carbon steel components in sheltered, raw water, and external environments
- loss of material and cracking for stainless steel components in borated water and raw water
- degradation due to gamma irradiation for boraflex panels in borated water
- loss of material and cracking of soil earthen embankments
- cracking and separation of silicone fire barrier penetration seals
- cracking of rubber fire barrier penetration seals
- cracking and change in material properties of rubber and silicone flood seals
- cracking of masonry block walls
- loss of material of composite roofing material

In a letter dated June 26, 2002, the applicant provided AMR results tables for the passive, long-lived structures and components associated with the offsite power path in response to RAIs 2.5-1 and 2.5-2. The applicant subsequently included these structures and components in revised LRA Tables 3.5-1, 3.5-2, and 3.5-3, which were submitted to the staff by letter dated October 28, 2002. In its resolution of SER open item 3.5-1 (documented in Section 3.5.1.2.1 of this SER), the applicant identified cracking, change in material properties, and loss of material as applicable aging effects for the above-grade concrete components. For steel components, the applicant identified loss of material as an applicable aging effect for components in a sheltered or external environment. In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

#### 3.5.2.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection
- Standby Nuclear Service Water Pond Dam Inspection
- Fire Protection Program
- Inspection Program for Civil Engineering Structures and Components
- Underwater Inspection of Nuclear Service Water Structures
- Fluid Leak Management Program
- Chemistry Control Program

In its October 28, 2002, response to SER open item 3.5-1, which included the passive, long-lived structures and components associated with the offsite power path (provided by the applicant in response to SER open item 2.5-1), the applicant committed to manage the aging of these electrical components through its Inspection Program for Civil Engineering Structures and Components.

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

A description of these AMPs is provided in Appendix B of the LRA or subsequent correspondence from the applicant. The applicant concludes that the effects of aging associated with the components in structures outside the reactor building will be adequately managed by these AMPs during the period of extended operation.

### *3.5.2.2 Staff Evaluation*

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in LRA Section 2.4, “Scoping and Screening Results: Structures,” and the applicable aging management program descriptions provided in LRA Appendix B to determine whether the aging effects for the components in structures outside the reactor building have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s AMPs credited for the aging management of the components in structures outside the reactor building at McGuire and Catawba nuclear stations. The staff’s evaluation includes a review of the aging effects considered and the basis for the applicant’s elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the components in structures outside the reactor building.

3.5.2.2.1 Aging Effects

Section 3.5.2 of the LRA provides an aging management review of the components in structures outside the reactor building. Table 3.5-2 of the LRA is divided into three sections: (1) concrete structural components, (2) steel structural components, and (3) other structural components. The staff's evaluation of the applicant's aging management review for these components follows.

Concrete: The applicant identified change in material properties as an applicable aging effect for reinforced concrete beams, columns, floor and roof slabs, and walls that are exposed to an external environment. In addition, the applicant identified change in material properties as an applicable aging effect for the refueling water storage tank missile shield wall. The applicant also identified loss of material and cracking as applicable aging effects for concrete exposed to a raw water environment. Cracking is also identified as an applicable aging effect for the concrete fire walls, which are in a sheltered environment.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The staff noted that Table 3.5-2 of the LRA identifies an applicable aging effect (change in material properties) only for the refueling water storage tank missile shield wall and not for the other missile shield walls. By letter dated January 28, 2002, the staff requested, in RAI 3.5-8, the applicant to explain why loss of material, cracking, and change in material properties had not been identified as applicable aging effects for the other missile shield walls. In addition, the staff requested, in RAI 3.5-7, that the applicant identify the aging management program(s) that will be used to manage the aging effects for the many other concrete components in LRA Table 3.5-2 for which no aging effects are identified. In its response dated March 11, 2002, the applicant stated that the concrete components listed in LRA Table 3.5-2 were designed using the appropriate ACI and ASTM standards, which resulted in dense concrete with a suitable cement content that has been well cured and is less susceptible to calcium hydroxide loss (leaching). In addition, the applicant stated that operating experience to date has not shown any significant degradation of the concrete components listed in Table 3.5-2 of the LRA, for which no aging effects are identified. Therefore, with a few exceptions, only concrete components exposed to raw water and external environments have applicable aging effects that require aging management during the period of extended operation.

As stated earlier in Section 3.5.1.2.1 of this SER, the staff considers that sound material design and construction together with sound inspection programs are both necessary to maintain the serviceability of concrete nuclear structures. Periodic visual inspections (1) can provide significant quantitative and qualitative data regarding structural performance and extent of degradation, (2) are vital to monitor the effects of operating and environmental conditions, and (3) enable the timely identification and correction of degraded conditions. In conclusion, periodic inspections of concrete components during the period of extended operation are necessary in order for the staff to make a reasonable assurance finding that in-scope concrete structures and components will maintain their structural integrity and intended function(s). Periodic visual inspections of concrete nuclear structures are a vital part of the license renewal program. On this basis, the staff disputes the applicant's claim, in response to RAIs 3.5-7 and 3.5-8, that AMPs are necessary only for the above-grade concrete components, listed in Tables

3.5-1 and 3.5-2 of the LRA, that are exposed to harsh environments. This issue was identified in Section 3.5.1.2.1 of this SER as open item 3.5-1.

The applicant resolved open item 3.5-1 by committing to manage the aging of accessible concrete components during the period of extended operation. Specifically, the applicant committed to manage loss of material, cracking, and change in material properties for accessible concrete structural components using its Inspection Program for Civil Engineering Structures and Components. For the passive, long-lived structures and components associated with the offsite power path that were brought into the scope of license renewal, the applicant committed to manage loss of material, cracking, and change in material properties using its Inspection Program for Civil Engineering Structures and Components. This commitment is consistent with the applicant's aging management of other accessible concrete structural components as proposed in response to open item 3.5-1. Resolution of open item 3.5-1 is documented in further detail in Section 3.5.1.2.1 of this SER.

For below-grade concrete components listed in Table 3.5-2 of the LRA, the staff has determined that aging management is unnecessary if applicants are able to show that the below-grade soil/groundwater environment is non-aggressive. In RAI 3.5-1, the staff requested that the applicant provide further information regarding the chemistry of the groundwater samples taken at both Catawba and McGuire Nuclear Stations. The applicant's response to RAI 3.5-1 is discussed in more detail above in Section 3.5.1.2.1 of this SER. Briefly, the applicant showed that the chloride, sulfate, and pH values over the past 20 to 30 years are well below the limits where potential degradation of concrete may occur. Therefore, aging management of below-grade concrete components, listed in Table 3.5-2 of the LRA, during the period of extended operation is unnecessary. However, the applicant does not commit, in its response to RAI 3.5-1, to further monitor the groundwater or to initiate corrective action in the event of a chemical release during the period of extended operation. This is identified in Section 3.5.1.2.1 of this SER as open item 3.5-2.

In response to open item 3.5-2, the applicant stated that it did not commit to initiate a corrective action in the event of a potential change to the site environment, resulting from a chemical release during the period of extended operation, because such an event was not postulated. The applicant stated that it is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Catawba or McGuire. Such a change in the environment due to a chemical release would be an abnormal event. As stated in NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," aging effects from abnormal events need not be postulated specifically for license renewal. The staff concurs with the applicant's determination that a potential change to the site environment resulting from a chemical release during the period of extended operation would be an abnormal event. Therefore, such a chemical release would not need to be included in an aging management review, and the staff considers open item 3.5-2 to be closed.

<u>Steel</u>: Table 3.5-2 of the LRA identifies (1) loss of material for carbon steel components in sheltered, raw water, and external environments and (2) loss of material and cracking for stainless steel components in borated water and raw water as applicable aging effects for the steel components in structures outside the reactor building. The staff finds that the applicant's approach for evaluating the applicable aging effects for the steel components in structures

outside the reactor building to be reasonable and acceptable.  The staff concludes that the applicant has properly identified the aging effects for steel components in these structures.

Other Materials:  Table 3.5-2 of the LRA identifies the following aging effects for other material components (besides concrete and steel) in structures outside the reactor building:

- degradation due to gamma irradiation for boraflex panels in borated water
- loss of material and cracking of soil earthen embankments
- cracking and separation of silicone fire barrier penetration seals
- cracking of rubber fire barrier penetration seals
- cracking and change in material properties of rubber and silicone flood seals
- loss of material of composite roofing material

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The staff finds that the applicant's approach for evaluating the applicable aging effects for the other material components in structures outside the reactor building to be reasonable and acceptable.  The staff concludes that the applicant has properly identified the aging effects for the other material components in these structures.

3.5.2.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following AMPs with managing the identified aging effects for the components in structures outside the reactor building:

- Boraflex Monitoring Program
- Flood Barrier Inspection
- Standby Nuclear Service Water Pond Dam Inspection
- Fire Protection Program
- Inspection Program for Civil Engineering Structures and Components
- Underwater Inspection of Nuclear Service Water Structures
- Fluid Leak Management Program
- Chemistry Control Program

In its November 14, 2002, response to SER open item 2.3-3, the applicant identified the Ventilation Area Pressure Boundary Sealants Inspection to manage the effects of cracking and shrinkage of structural sealant due to exposure to ambient conditions.

The latter five AMPs listed above (Fire Protection Program, Inspection Program for Civil Engineering Structures and Components, Underwater Inspection of Nuclear Service Water Structures, Fluid Leak Management Program, Chemistry Control Program) and Ventilation Area Pressure Boundary Sealants Inspection are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the  components in structures outside the reactor building.  The staff's review of the common AMPs is documented in Section 3.0 of the SER.  The staff's evaluation of the Boraflex Monitoring Program, Flood Barrier Inspection Program, and Standby Nuclear Service Water Pond Dam Inspection AMPs follows.

Boraflex Monitoring Program

The applicant described its Boraflex Monitoring Program in Section B.3.3 of LRA Appendix B. The staff reviewed the application to determine whether the applicant had demonstrated that the boraflex surveillance program 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 Boraflex Monitoring Program, applicable only to McGuire, is credited for managing the aging of boraflex panels for the period of extended operation. The Boraflex Monitoring Program is a performance monitoring program that manages the degradation of the panels in the spent fuel storage racks due to gamma irradiation. The boraflex panels ensure that the reactivity of the storage fuel assemblies is maintained within required limits. In addition, the applicant references the McGuire SLC 16.9.24, “Spent Fuel Pool Storage Rack Poison Material,” which contains additional information related to the management of the boraflex panels.

The staff’s evaluation of the Boraflex Monitoring 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.

[Program Scope] The Boraflex Monitoring Program includes all boraflex neutron-absorbing panels in the McGuire 1 and 2 spent fuel storage racks. The staff agrees that it is appropriate to include this material component within the scope of the boraflex monitoring program.

[Preventive or Mitigative Actions] The Boraflex Monitoring Program has no associated preventive or mitigative actions. The staff concludes that there are no preventive or mitigative actions to prevent the further breakdown of the polymer matrix and eventual release of boron carbide into the spent fuel pool (SFP). However, based on the known mechanism governing the polymer matrix breakdown, the staff requested information related to the SFP clean up system and any steps taken to limit the disturbance of the quiescent state of the spent fuel pool. In a conference call on August 21, 2001, the applicant clarified for the staff that the SFP cleanup system is run continuously. In addition, the demineralizer efficiency of silica removal is 1 percent. The applicant also stated that its predictive model of boraflex degradation accounts for the continuous operation of the SFP cleanup system. This clarifying information is documented in a conference call summary dated September 10, 2001. The staff finds that this clarifying information does not adversely impact the aforementioned conclusion.

[Parameters Monitored or Inspected] The Boraflex Monitoring Program monitors the boraflex panel average storage rack poison material by measuring the Boron-10 areal density. The panel average Boron-10 areal density is used as an input to the spent fuel pool storage rack criticality calculations. In addition, the silica levels are monitored in the spent fuel pool which provide an indication of the depletion of boron carbide from boraflex. The staff finds that the parameters inspected and monitored under this program are appropriate and adequate to determine degradation of the boraflex panels in the spent fuel racks.

[Detection of Aging Effects] The Boraflex Monitoring Program will monitor boraflex panel areal density prior to loss of intended function. The staff finds that this testing parameter, in conjunction with silica concentration monitoring, is effective and adequate in detecting the aging effects associated with degradation of the boraflex panels.

[Monitoring and Trending] The Boraflex Monitoring Program includes in-situ testing of the Boron-10 areal density at a frequency of every 3 years. The applicant further stated that testing may be performed more frequently based on engineering judgment, spent fuel pool water chemistry, and modeling projections of boraflex degradation. Selection of boraflex panels for in-situ testing is based on predicted Boron-10 areal density loss. The staff finds that it is appropriate and prudent to monitor and trend density changes of the boraflex panels.

[Acceptance Criteria] The acceptance criteria for the Boraflex Monitoring Program is based on maintaining the minimum areal density of boron carbide assumed in the criticality calculations. These requirements are provided in the McGuire SLC 16.9.24, "Spent Fuel Pool Storage Rack Poison Material." The staff agrees that the acceptability of boraflex degradation should be controlled by the assumptions in the criticality analysis and, based on the requirements provided in SLC 16.9.24, concludes that this program has appropriate acceptance criteria to ensure that the boraflex panels continue to meet their intended function.

[Operating Experience] The application stated blackness testing was performed at McGuire in 1991. This testing measured shrinkage as well as size and frequency of gap formation. The data obtained from this testing was incorporated into the revised criticality analyses discussed in Reference B-7 of the LRA. As a result of NRC-issued Generic Letter (GL) 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks," the applicant provided two responses as discussed in References B-7 and B-9 of the LRA. The applicant stated that the responses to GL 96-04 indicate that the EPRI RACKLIFE computer code had been acquired to assess overall boraflex thinning based on cumulative gamma exposure, storage rack design parameters, and dissolved silica concentration in the spent fuel pool. In addition, the applicant stated that in-situ measurements were performed that verified that this monitoring program accurately predicts the Boron 10 areal density.

The staff has reviewed SLC 16.9.24 and its basis (i.e., the staff's Safety Evaluation to Amendment No. 197 to Facility Operating License NPF-9 and Amendment No. 178 to Facility Operating License NPF-17, transmitted by NRC letter dated November 27, 2000). The SLC is designed to ensure that an unplanned criticality event cannot occur as a result of degraded boraflex conditions. In a conference call on August 21, 2001, the applicant confirmed for the staff that the measured boraflex degradations were within the limits imposed by the SLC. In addition, the applicant clarified that although the RACKLIFE predictive code had not been used to project boraflex degradation in the period of extended operation, the applicant has initiated activities to remediate anticipated unacceptable loss of boraflex. This clarifying information is documented in the conference call summary dated September 10, 2001.

Based on the details of the operating experience in this program, the staff finds that this program will continue to address the boraflex degradation at McGuire.

FSAR Supplement: The McGuire SLC program constitutes Chapter 16 of the McGuire UFSAR and its contents are maintained in a separate manual. The Boraflex Monitoring Program is a current program with requirements found in SLC 16.9.24. The staff has reviewed SLC 16.9.24 and finds that it contains the appropriate elements of this program.

In conclusion, the staff has reviewed the boraflex monitoring program in Section B.3.3 of LRA Appendix B. On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the effects of aging associated with the Boraflex Monitoring Program will be adequately managed, so 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).

<u>Flood Barrier Inspection</u>

The applicant described its Flood Barrier Inspection program in Section B.3.13 of LRA Appendix B. The applicant credits this program for managing the aging effects associated with the elastomeric flood seals that protect equipment such that no safety-related intended functions or safe shutdown capabilities are adversely impacted. This program is used only for McGuire; at Catawba, the flood barriers are inspected as part of the Inspection Program for Civil Engineering Structures and Components. The staff reviewed Section B.3.13 of LRA Appendix B to determine whether the applicant had demonstrated that Flood 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).

Section B.3.13 of LRA Appendix B states that the purpose of the Flood Barrier Inspection activities is to manage aging effects of the elastomeric flood seals to ensure that safety-related equipment is protected from floods and flooding flow paths, such that no equipment safety-related intended functions or station safe shutdown capabilities are adversely impacted. The applicant stated that this is a condition monitoring program that applies only to McGuire. The flood barriers at Catawba are inspected as part of the Inspection Program for Civil Engineering Structures and Components. Cracking and change in material properties of flood seals are identified as aging effects that require monitoring for the period of extended operation. This program was initiated in response to NRC Information Notice 87-49, “Deficiencies in Outside Containment Flooding Protection,” to ensure that flood protection features outside containment are properly installed and maintained. This program monitors the cracking and separation of the internal elastomeric flood seals. Structures and components that do not meet the acceptance criteria are evaluated for continued service and repaired as required. Corrective actions and confirmatory actions, as needed, are implemented in accordance with the corrective action program.

The staff’s evaluation of the Flood Barrier 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 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.

[Program Scope]  Section B.3.13 of LRA Appendix B identifies the scope as the internal elastomeric flood seals outside containment that protect equipment from floods and flood flow paths such that no equipment safety-related intended functions or station safe shutdown capabilities are adversely impacted.  This program is applicable only to McGuire; at Catawba, the flood barrier seals inspections are implemented through the Inspection Program for Civil Engineering Structures and Components.  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.3.13 of LRA Appendix B identifies cracking and change in material properties that would challenge the function of the flood barrier seals 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 flood barriers are acceptable to the staff.

[Detection of Aging Effects]  Section B.3.13 of LRA Appendix B states that visual inspection will detect cracking and change in material properties of elastomeric flood seals prior to the loss of structure or component intended functions.  The use of visual inspection of the external condition of elastomeric seals is considered by the staff to be a reasonable means of detecting cracking and change in material properties before the loss of intended function.

[Monitoring and Trending]  Section B.3.13 of LRA Appendix B states that the flood seals are inspected by visual inspection at a frequency of 18 months.  No actions are taken as part of the program to trend the inspection results.  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.3.13 of LRA Appendix B states that the acceptance criteria is no unacceptable visual indications of cracking and change in material properties that would result in loss of intended function.  The assessment of the severity of the observed degradation and determination of whether corrective action is necessary is based on the judgment of the inspector.  By letter dated January 28, 2002, the staff requested, in RAI B.3.13-1, the applicant to describe 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 McGuire management assigns the personnel who perform the inspection of the flood barriers.  The individuals are chosen based on education and work experience to ensure that they are well-qualified.  The inspector visually examines the flood seals for cracking and change in material properties that would result in loss of the intended function of the seal. The assessment of the severity of the observed degradation and the determination of whether corrective action is necessary are based on the judgment of the inspector.  If the inspector identifies degradation that would lead to loss of intended function, a corrective action report will be initiated.  The corrective action process is a formalized process, in accordance with 10 CFR Part 50, Appendix B, quality assurance requirements, for documenting engineering evaluations of plant problems and 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 staff finds that, 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, the applicant's response is acceptable.

[Operating Experience] Section B.3.13 of LRA Appendix B describes the plant-specific operating experience related to the inspections of the flood barrier seals. The inspections have resulted in repairs for a variety of reasons to ensure that the intended functions continue to be met. From this, the applicant concludes that the program had been demonstrated to be effective in managing cracking and change in material properties of the elastomeric flood seals. The staff concurs that the program as described and the inspection frequency provide reasonable assurance that the intended function of the flood seals will continue to be met.

FSAR Supplement: The staff reviewed LRA Appendix A, Section 18.2.9, the FSAR supplement for McGuire. The FSAR supplement indicates that the program includes periodic visual inspections of the flood seals to identify degradation that could result in loss of the intended functions of the flood seals. The staff finds that the description of the applicant's flood barrier seal inspection activities is consistent with Section B.3.13 of LRA Appendix B and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.13 of LRA Appendix B and the summary description of the flood barrier seal inspection activities in LRA Appendix A, Section 18.2.9, the FSAR supplement for McGuire. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAI. On the basis of its review and the above evaluation, the staff finds that the aging effects of the flood barrier seals will be adequately managed 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).

Standby Nuclear Service Water Pond Dam Inspection

The applicant described its Standby Nuclear Service Water Pond (SNSWP) Dam Inspection activities in Section B.3.30 of LRA Appendix B. The applicant credits this inspection activity with managing the potential aging of the SNSWP dams. The staff reviewed Section B.3.30 of LRA Appendix B to determine whether the applicant had demonstrated that SNSWP Dam 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).

Section B.3.30 of LRA Appendix B states that the purpose of the SNSWP Dam Inspection activities is to provide reasonable assurance that the effects of aging will be managed so that the intended function of the SNSWP dam will be maintained consistent with the CLB during the period of extended operation. Loss of material and cracking of earthen embankments have been identified as aging effects requiring management for the SNSWP dam for the period of extended operation. The SNSWP Dam Inspection program is credited with managing these aging effects. The scope of the program includes the upstream and downstream slopes, the spillway overflow/outlet works, the area near the right and left abutments, and the toe of the dam. A visual examination is performed for erosion, settlement, slope stability, seepage, drainage systems, integrity of riprap, and environmental conditions. The inspections are performed on an annual basis as required by McGuire Technical Specification Surveillance Requirement (SR) 3.7.8.3 and Catawba Technical Specification SR 3.7.9.3. In addition, the results of the piezometric readings and settlement monitoring are reviewed. Piezometers are located on the dam to monitor foundation core pressure. The piezometers are read quarterly. Survey monuments are located on the crest along the entire length of the dam to provide information on settlement. Surveys of the monuments are performed annually. The inspections are performed in accordance with the guidance in Regulatory Guide (RG) 1.127, “Inspection of Water-Control Structures Associated with Nuclear Power Plants.”

The applicant stated that acceptance criteria are the absence of visual indications of abnormal degradation, vegetation growth, erosion, or excessive seepage that would affect the SNSWP dam operability. Structures and components which do not meet the acceptance criteria are evaluated by the “accountable engineer” for continued service and repaired as required. Each inspection records the recommendations concerning repairs or studies. 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’s operating experience, described in the LRA, shows that no conditions have been observed which have adverse effects on the intended function of the SNSWP dam at McGuire or Catawba. Corrective action programs at both sites effectively take care of minor maintenance activities.

The staff’s evaluation of the SNSWP Dam Inspection 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 TS. 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.

[Program Scope] Section B.3.30 of LRA Appendix B identifies the scope as the SNSWP dam, including the upstream and downstream slopes, the spillway overflow/outlet works, the area near the right and left abutments, and the toe of the dam. 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.3.30 of LRA Appendix B states that the examination guidelines are in accordance with RG 1.127. The dam is visually examined for erosion, settlement, slope stability, seepage, drainage systems, integrity of riprap, and environmental conditions. In addition, the results of the piezometric readings of foundation core pressure and survey monument readings of settlement are reviewed. The applicant’s March 11, 2002, response to the staff’s request for additional information states that, in accordance with RG 1.127, both faces of the dam are inspected for seepage, slides, erosion, abnormal degradation, and vegetative growth. Because these inspections can be used to identify the degraded conditions noted by the applicant, such inspections of the SNSWP dam are acceptable to the staff.

[Detection of Aging Effects] Section B.3.30 of LRA Appendix B states that visual inspection will detect cracking and loss of material of the SNSWP dam. The dam is visually examined for erosion, settlement, slope stability, seepage, drainage systems, integrity of riprap, and environmental conditions. In addition, the results of the piezometric readings of foundation core pressure and survey monument readings of settlement are reviewed. Both faces of the dam are inspected for seepage, slides, erosion, abnormal degradation, and vegetative growth. The above inspections provide an effective means of detecting cracking and loss of material of the SNSWP dam and are acceptable to the staff.

[Monitoring and Trending] Section B.3.30 of LRA Appendix B states that the visual inspections are conducted annually, in accordance with the site TS, the piezometers are read quarterly, and the survey monuments are checked annually. Inspection reports are retained in sufficient detail to permit adequate confirmation of the inspection results. The records identify past inspection results, the results of the most recent inspection, whether the results were acceptable, discrepancies and their cause, and any corrective action resulting from the inspection. The applicant's March 11, 2002, response to the staff's request for additional information states that, if degradation is evident that would lead to the loss of intended function, an evaluation of the problems would be performed, including the need for further inspections of other locations. The staff finds that the monitoring and trending of SNSWP dam aging is effective and, therefore, acceptable.

[Acceptance Criteria] Section B.3.30 of LRA Appendix B states that the acceptance criteria are no unacceptable visual indications of abnormal degradation, vegetation growth, erosion, or excessive seepage that would affect the SNSWP dam operability. By letter dated January 28, 2002, the staff requested, in RAI B.3.30-3, the applicant to describe the acceptance 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 acceptance criteria follow the guidance provided in codes and standards, such as RG 1.127 and 18 CFR Part 12. The assessment of the severity of the observed degradation and the determination of whether corrective action is necessary is performed by the "accountable engineer." By letter dated January 28, 2002, the staff requested, in RAI B.3.30-2, additional information regarding the qualifications of the accountable engineer. In its March 11, 2002, response, the applicant stated that the accountable engineer is chosen based on education and work experience. It further stated that the accountable engineer qualifications are in accordance with RG 1.127. The accountable engineer should be a registered professional engineer experienced in the investigation, design, construction, and operation of dams. 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, the staff finds the applicant's responses to these RAIs acceptable.

[Operating Experience] Section B.3.30 of LRA Appendix B describes the plant-specific operating experience related to the inspections of the SNSWP dam. The inspections have found the dams to be in good condition, with no conditions identified that would have adverse effects on the intended function of the dams. At McGuire, the most common recommendations were to spray the riprap on the upstream face and downstream toe of the dam to kill vegetation, repair ruts, and re-seed. Structurally, cracks found in the vicinity of the concrete drainage ditch have been cleaned out and sealed with appropriate sealer. At Catawba, the most common recommendations are to clear vegetation from the concrete drainage ditches, pack soil and gravel along the sides of the concrete drainage ditch, and monitor any signs of erosion along the sides of the concrete drainage ditch. Further, dam safety audits, performed by the NRC in 1994 and 1998 for McGuire, and in 1997 and 1999 for Catawba, concluded that there were no conditions that would indicate an immediate or adverse threat to the safety and permanence of the SNSWP dams. From this the applicant concludes that the program had been demonstrated to be effective in managing cracking and loss of material of the SNSWP dams at Catawba and McGuire. The staff concurs that the program as described and the inspection frequency provide reasonable assurance that the intended function of the SNSWP dam will continue to be met.

FSAR Supplement: The applicant did not propose a FSAR supplement for the SNSWP Dam Inspection activities. A summary description already exists in the bases section for Technical Specification SR 3.7.8.3 for McGuire and SR 3.7.9.3 for Catawba. The staff reviewed the TS and finds the description consistent with Section B.3.30 of LRA Appendix B and, therefore, acceptable.

In conclusion, the staff reviewed the information provided in Section B.3.30 of LRA Appendix B and the summary description of the SNSWP Dam Inspection activities in the Technical Specification bases section. In addition, the staff considered the applicant's March 11, 2002, response to the staff's RAIs. On the basis of its review and the above evaluation, the staff finds that the aging effects of the SNSWP dam will be adequately managed 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).

#### *3.5.2.3 Conclusions*

The staff reviewed the information in LRA Table 3.5.2, as well as the applicable aging management program descriptions in LRA Appendix B. On the basis of its review, and with the resolution of open items 3.5-1 and 3.5-2, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside the reactor building will be adequately managed, so that there is reasonable assurance that these structural components 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).

### 3.5.3 Component Supports

#### *3.5.3.1 Technical Information in the Application*

The aging management review results for component and equipment supports are presented in Table 3.5-3 of the LRA. Table 3.5-3 of the LRA identifies the component and equipment support (1) function, (2) material, (3) environment, (4) aging effects, and (5) AMPs and activities.

Component supports are those components that provide support or enclosure for mechanical and electrical equipment. Component supports include battery racks, cable tray and conduit, cable tray and conduit supports, control boards, crane rails, enclosures, equipment component supports, HVAC duct supports, instrument line supports, instrument racks and frames, lead shielding supports, new fuel storage racks, pipe supports, stair, platform and grating supports, and spent fuel storage racks.

Also included within the scope of component supports are the Class 1 nuclear steam supply system (NSSS) supports. These Class 1 component supports include RCS piping supports; pressurizer upper and lower lateral supports; reactor vessel support; control rod drive seismic structure supports; steam generator vertical, lower lateral, and upper supports; and reactor coolant pump lateral and vertical support assemblies.

The materials of construction for the component supports, which are subject to an AMR, are steel or stainless steel and are located in all of the structures within the scope of license renewal for McGuire and Catawba.

The component and equipment supports are exposed to external, sheltered, reactor building, raw water, and borated water environments.

3.5.3.1.1 Aging Effects

Table 3.5-3 of the LRA identifies the following applicable aging effects for the component and equipment supports:

- loss of material for most steel components in sheltered or external environments
- cracking and loss of material for stainless steel spent fuel storage racks in borated water

3.5.3.1.2 Aging Management Programs

Table 3.5-3 of the LRA credits the following AMPs with managing the identified aging effects for the component and equipment supports:

- Battery Rack Inspections
- Crane Inspection Programs
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- ISI Plan — Subsection IWF
- Underwater Inspection of Nuclear Service Water Structures
- Chemistry Control Program

A description of these AMPs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building and other structures will be adequately managed by these AMPs during the period of extended operation.

*3.5.3.2 Staff Evaluation*

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in LRA Section 2.4, “Scoping and Screening Results: Structures,” and the applicable aging management program and activity descriptions provided in LRA Appendix B to determine whether the aging effects for the component supports have been properly identified and will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's AMPs credited for the aging management of the component supports at McGuire and Catawba. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the AMPs that are credited for managing the identified aging effects for the component supports.

3.5.3.2.1 Aging Effects

Each of the in-scope component supports listed in Table 3.5-3 are either steel or stainless steel components. For the stainless steel spent fuel storage racks exposed to borated water, Table 3.5-3 of the LRA identifies cracking and loss of material as applicable aging effects. However, in Table 3.5-3 of the LRA, the applicant does not distinguish between carbon steel and galvanized steel components. For most of the steel component supports listed in LRA Table 3.5-3, the applicant lists loss of material as an applicable aging effect. However, for some steel component supports, no aging effects are identified. By letter dated January 28, 2002, the staff requested, in RAI 3.5-9, that the applicant state the type of steel used for the component supports listed in LRA Table 3.5-3 that do not have any applicable aging effects.

In its response, dated March 11, 2002, the applicant stated that metal housing systems, such as control boards, electrical and instrument panels, enclosures, etc., that are constructed of factory baked painted steel or galvanized sheet metal do not have a tendency to age with time[7]. Industry operating experience with metal housing systems indicates that they have performed without failure to the present[8]. Therefore, loss of material is not an aging effect requiring management for electrical panels, enclosures, and control boards in sheltered (reactor building) and external environments.

The applicant further states that the cable trays in the reactor building are constructed of painted or galvanized sheet metal similar to the metal housings and located in the same sheltered environment; therefore, the cable trays would age similarly to the metal housings. A review of industry operating experience was also implemented to validate this conclusion. Deficiencies that were identified were event driven or design/installation deficiencies. Therefore, loss of material is not an aging effect requiring management for cable trays in sheltered (reactor building) and external environments.

The applicant asserted that the new fuel storage racks provide dry storage for new nuclear fuel. These racks are free standing and are designed to accommodate fuel assemblies. The storage racks are fabricated from painted carbon steel and are located in a mild, dry sheltered environment. A review of operating experience did not identify any aging effects requiring

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[7] "An Aging Assessment of Relay and Circuit Breakers and System Interactions," prepared by Franklin Research Center for Brookhaven National Laboratory, NUREG/CR-4715, June 1987

[8] "Aging Management Guideline for Commercial Nuclear Power Plants — Motor Control Centers," SAND 93-7069, Sandia National Laboratories, February 1994; and "Aging Management Guideline for Commercial Nuclear Power Plants — Electrical Switchgear," SAND 93-7027, Sandia National Laboratories, July 1993

management.  Therefore, loss of material is not an aging effect requiring management for the new fuel storage racks.

The staff evaluated the above technical justifications and finds them reasonable and adequate in scope to support the aging management review results described in LRA Table 3.5-3.  The staff finds that the applicant's approach for evaluating the applicable aging effects for component supports as described in LRA Table 3.5-3 is reasonable and acceptable.  The staff concludes that the applicant has properly identified the aging effects for the component supports.  The staff also concludes that the applicant has demonstrated that the aging effects for the component supports will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3.2.2 Aging Management Programs

Table 3.5-3 of the LRA credits the following AMPs with managing the identified aging effects for the component and equipment supports:

- Battery Rack Inspections
- Crane Inspection Programs
- Fluid Leak Management Program
- Inspection Program for Civil Engineering Structures and Components
- ISI Plan — Subsection IWF
- Underwater Inspection of Nuclear Service Water Structures
- Chemistry Control Program

The latter five AMPs listed above (the Fluid Leak Management Program, the Inspection Program for Civil Engineering Structures and Components, the ISI Plan — Subsection IWF, the Underwater Inspection of Nuclear Service Water Structures, and the Chemistry Control Program) are credited with managing the aging of several components in different structures and systems and are, therefore, considered common AMPs.  The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for the component and equipment supports.  The staff's review of the common AMPs is documented in Section 3.0 of the SER.  The staff's evaluation of the Battery Rack Inspections and the Crane Inspection Programs AMPs follows.

<u>Battery Rack Inspections</u>

The applicant described the Battery Rack Inspections program in Section B.3.2 of LRA Appendix B.  The applicant credits this program with managing the potential aging effect of loss of material of the battery racks.  The staff reviewed Section B.3.2 of LRA Appendix B to determine whether the applicant had demonstrated that the battery rack 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).

Section B.3.2 of LRA Appendix B states that the purpose of the Battery Rack Inspections activities is to provide reasonable assurance that the effects of aging will be managed such that the intended function of the battery racks is maintained through the period of extended operation.  Section B.3.2 of LRA Appendix B identifies the loss of material due to corrosion as an aging effect requiring programmatic management for steel battery racks.  The applicant stated that the Battery Rack Inspections activities are credited with managing loss of material that could impact the intended function of structural support. The Battery Rack Inspections program covers the following four battery systems:

- EPL system (vital batteries)
- EPQ system (diesel generator batteries)
- ETM system (standby shutdown facility batteries)
- EQD system (standby shutdown facility diesel batteries)

The applicant stated that the regulatory basis for inspecting battery racks is found in the McGuire and Catawba TS and SLCs as identified in the following:

McGuire:

- EPL system — TSSR 3.8.4.3
- EPQ system — SLC 16.8.3.3
- EQD system — SLC 16.9.7.12
- ETM system — SLC 16.9.7.17

Catawba:

- EPL system — TSSR 3.8.4.4
- EPQ system — TSSR 3.8.4.4
- EQD system — SLC 16.7-9.2
- ETM system — SLC 16.7-9.4

The applicant concluded that the continued implementation of the Battery Rack Inspections provides reasonable assurance that loss of material will be managed such that the intended functions of the battery racks will continue to be maintained consistent with the CLB for the period of extended operation.

The staff's evaluation of the Battery Rack Inspections 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 TS and 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.

[Program Scope] The applicant states in the LRA that the scope of the Battery Rack Inspections includes the battery racks for the following systems:

- EPL system (vital batteries)
- EPQ system (diesel generator batteries)
- ETM system (standby shutdown facility batteries)
- EQD system (standby shutdown facility diesel batteries)

The staff finds that the scope of the Battery Rack Inspections is adequate because it includes inspections of the essential battery racks for the plant systems.

[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] The parameters inspected include the visual examination of the battery racks for physical damage or abnormal deterioration, including the loss of material. The staff finds this is acceptable for the inspection of battery racks. However, degraded anchorage of the battery racks may lead to loss of battery rack intended function. Consequently, by letter dated January 28, 2002, the staff requested, in RAI B.3.2-1, the applicant to provide a description of how the inspections of the battery rack anchorages will ensure that deterioration of the anchorages does not lead to a loss of function for the battery racks. In its response dated March 11, 2002, the applicant stated that the Battery Rack Inspections use plant procedures to inspect for loss of material of the battery racks and all subcomponents (including battery rack nuts, bolts, rails, supports, seismic brace, and anchor bolts). The Battery Rack Inspections activities require visual examination of the battery racks, including subcomponents, for physical damage or abnormal deterioration, including loss of material due to corrosion. The applicant further stated that the inspection acceptance criterion for loss of material in the procedure is “no significant amount of corrosion or rust spots visible.” Physical damage or deterioration is evaluated to determine if the physical damage or deterioration affects the battery’s ability to perform its function. Since the inspections performed can detect degradation that would affect the intended function of the battery racks, the staff finds the applicant’s response acceptable.

[Detection of Aging Effects] The applicant stated that the battery rack visual inspections are performed every 18 months to detect loss of material in accordance with McGuire and Catawba TS and SLCs. Because visual inspection can be used to identify the degraded conditions noted by the applicant, such inspections of the battery racks are acceptable to the staff.

[Monitoring and Trending] Section B.3.2 of LRA Appendix B states that the visual inspections of the battery racks are performed every 18 months to detect loss of material in accordance with McGuire and Catawba TS and SLCs. The inspections are based on guidance provided in IEEE 450-1980 (Reference B-6 of the LRA). No actions are taken as part of this program to trend inspection results.

The staff finds that these monitoring activities are acceptable and agrees that no actions are needed as part of this program to trend inspection results.

[Acceptance Criteria] The applicant stated that the acceptance criterion is no visual indication of loss of material. However, it is not clear to what extent the loss of material is acceptable. Consequently, by letter dated January 28, 2002, the staff asked, in RAI B.3.2-1, the applicant to describe 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 procedure acceptance criteria for loss of material are “no significant amount of corrosion or rust spots visible,” and that visual inspections for these types of degradation have been addressed in NRC Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants,” and NEI 96-03, “Industry Guideline for Monitoring Structures.” The staff finds these procedure guidelines acceptable for assessing the adequacy of the degraded battery racks including subcomponents.

[Operating Experience]  The applicant stated that a review of McGuire and Catawba specific surveillance records did not identify any instances where abnormal deterioration, which would include loss of material, of the battery racks had occurred.  The staff finds that the applicant's operating experience indicates that the applicant's battery rack inspection activities are effective in managing the aging effects of the battery racks.

FSAR Supplement:  The staff reviewed Table 18-1 of LRA Appendix A-1 and LRA Appendix A-2 for McGuire and Catawba, respectively, and compared them with Section B.3.2 of LRA Appendix B.  The staff finds that Table 18-1 referenced the proper sections of McGuire and Catawba TS and SLCs; however, neither the FSAR supplement nor the referenced TS and SLCs provide adequate descriptions of the Battery Rack Inspections.  The applicant was requested to provide a summary description characterizing the important elements of the Battery Rack Inspections from Section B.3.2 of LRA Appendix B and the applicant's response to RAI B.3.2-1, as described above.  This issue was characterized as SER open item 3.5-4.  In its response dated October 2, 2002, the applicant provided revisions to Table 18-1 and Section 18.3 of the FSAR supplements for McGuire and Catawba.  The revised FSAR supplements stated that inspections of the structural supports and anchorages of the battery racks would be performed.  The staff finds the applicant's revisions acceptable, since inspection of these specific subcomponents of the battery rack structures is specified.  Therefore, open item 3.5-4 is closed.

In conclusion, the staff reviewed the information provided in Section B.3.2 of LRA Appendix B and the applicant's March 11, 2002, response to the staff's RAI.  On the basis of its review and the above evaluation, the staff finds that the applicant has demonstrated that the Battery Rack Inspections program will adequately manage the aging effects so 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).

<u>Crane Inspection Program</u>

The applicant describes its Crane Inspection Program activities in Section B.3.10 of LRA Appendix B.  The applicant credits this inspection activity with managing the potential aging of the cranes that are within the scope of license renewal.  The staff reviewed Section B.3.10 of LRA Appendix B to determine whether the applicant had demonstrated that the Crane Inspection Program activities will adequately manage the applicable effects of aging during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Section B.3.10 of LRA Appendix B identifies the loss of material as an aging effect requiring management for crane rails and girders for the period of extended operation.  The applicant stated that the purpose of the Crane Inspection Program is to manage loss of material for the steel rails and girders within the scope of license renewal.  This program has been in effect for many years at the applicant's facilities and is based on the guidance contained in ANSI B30.2.0, "Overhead and Gantry Cranes, Section 2-2, Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks, and Slings," ANSI B30.16, "Overhead Hoists (Underhung)," and the requirements contained in 29 CFR Chapter XVII, 1910.179.

The applicant concluded that the continued implementation of the Crane Inspection Program provides reasonable assurance that loss of material will be detected and managed such that the intended function of the crane and hoist rails and girders will continue to be maintained consistent with the current licensing basis for the period of extended operation.

The staff's evaluation of the Crane 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 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.

[Program Scope] Section B.3.10 of LRA Appendix B states that the scope of the Crane Inspection Program includes seismically restrained cranes. This program scope is acceptable to the staff.

[Preventive Actions] The LRA states that no actions are taken as part of this program to prevent aging effects or mitigate aging degradation, and the staff did not identify the need for such actions.

[Parameters Monitored or Inspected] Section B.3.10 of LRA Appendix B states that the parameters monitored or inspected for the Crane Inspection Program are the crane rails and girders for loss of material. The staff finds that these are adequate because they include the inspection of the steel rails and girders of seismically restrained cranes within the scope of license renewal.

[Detection of Aging Effects] The program detects the aging effects of loss of material through visual examination of the crane rails and girders. The staff considers visual inspection to be an effective method of detecting loss of material in crane rails and girders; therefore, the staff finds this acceptable.

[Monitoring and Trending] The program detects aging effects through visual examination of the crane rails and girders. Inspection procedures for cranes and hoists are identified in plant procedures and are in accordance with industry standards, plant experience, and other industry experience. The applicant stated that each crane and hoist is subject to several inspections. Prior to initial use, all new, reinstalled, altered, modified, extensively repaired, and newly erected cranes are inspected, and the results of the inspections are documented. The applicant further stated that additional inspections are conducted prior to crane operation, quarterly, and/or annually depending on the specific crane or hoist. The inspection frequencies for the cranes and hoists are based on the guidance provided by ANSI B30.2.0 and ANSI B30.16 and are considered acceptable. Plant experience supports the established frequency as being timely and effective. The applicant also indicated that no actions are taken as part of this program to trend inspection or test results.

The staff finds that these monitoring activities are adequate and the inspection frequencies based on the industry standard guidance are acceptable and agrees that no actions are necessary for this program to trend inspection or test results.

[Acceptance Criteria]  Section B.3.10 of LRA Appendix B states that the acceptance criterion is no unacceptable visual indication of loss of material.  The acceptance criterion is specified in the crane and hoist inspection procedures. However, it is not clear to what extent the loss of material is acceptable.  Consequently, by letter dated January 28, 2002, the staff requested, in RAI B.3.10-1, 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 acceptability of crane rails and girders is based on condition monitoring.  Acceptability based on condition monitoring is described in NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”  The criteria for visual inspection for degradation of crane rails and girders are in accordance with criteria identified in ASME/ANSI requirements and OSHA regulations.  The applicant also stated that visual inspection for these types of degradation has been addressed in NRC Inspection Procedure 62002, “Inspection of Structures, Passive Components, and Civil Engineering Features at Nuclear Power Plants,” and NEI 96-03, “Industry Guideline for Monitoring Structures.”  The staff finds the acceptance criteria to be acceptable.

[Operating Experience]  The applicant stated that the McGuire experience has found no adverse aging conditions with crane rails and girders.  The significant operating experience history related to cranes dealt with functional issues.  The applicant stated that the Catawba experience has found no adverse aging conditions with crane rails and girders.  Most issues that were identified were related to electrical equipment associated with the cranes.  The staff finds that the McGuire and Catawba operating experience indicates that the applicant’s Crane Inspection Program is effective in managing the aging effects of the cranes.

FSAR Supplement:  The staff reviewed the FSAR supplement provided in UFSAR Section 18.2.7 as presented in Appendix A-1 and Appendix A-2 of the LRA for McGuire and Catawba, respectively, and compared this information to that which was provided in Section B.3.10 of LRA Appendix B and the clarifications provided by the applicant in response to RAI B.3.10-1.  The staff finds that some important industry standards and the NRC guidelines used for the AMP are not incorporated into Section 18.2.7 of the FSAR supplements.  The applicant was requested to update the FSAR supplements to incorporate those standards and guidelines. This issue was characterized as SER open item 3.5-5.  In its response dated October 2, 2002, the applicant provided revised summary descriptions of the Monitoring and Trending attribute for this inspection program.  For McGuire and Catawba, revised FSAR supplements incorporated the codes and standards listed in the RAI response.  The staff finds the applicant’s revised the FSAR supplements acceptable because they ensure that the program will be governed by these codes and standards.  Therefore, open item 3.5-5 is closed.

In conclusion, the staff reviewed the information provided in Section B.3.10 of LRA Appendix B and the summary description of the crane inspection activities in Appendix A of the LRA.  In addition, the staff considered the applicant’s March 11, 2002, response to the staff’s RAI.  On the basis of its review and the above evaluation, the staff finds that the Crane 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).

*3.5.3.3 Conclusions*

The staff reviewed the information in Table 3.5.3 of the LRA, as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the equipment and component supports will be adequately managed, so that there is reasonable assurance that these supports 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).

**3.5.4 Aging Management Review for High-Strength Structural Bolting**

Table 3.5-3 of the LRA provides no information to address crack initiation and growth from SCC for high-strength, low-alloy bolts. The last item on page 3.5-18 of Table 3.5-1 of the SRP-LR addresses the issue of bolting integrity for ASME Class I piping and components supports. It indicates that no further evaluation is required if there is a bolting integrity program to address the cracking initiation and growth from SCC for high-strength, low-alloy bolts. By letter dated January 23, 2002, the staff requested, in RAI 3.2-1, that the applicant state whether there is such a program and provide the reference.

*3.5.4.1 Aging Effects*

In its response dated April 15, 2002, the applicant stated that structural bolting used in various structural components would be addressed. High-strength structural bolting is included as part of a structural component, such as a pipe support, equipment support, structural steel, etc., and is addressed in Section 3.5 of the LRA. According to industry literature, most degradation of structural connections results from galvanic or anodic corrosion. Loss of material is the aging effect requiring management during the period of extended operation.

Regarding stress corrosion cracking of high-strength, low-alloy structural bolting, the applicant stated that industry experience revealed a common feature of the failures. It shows that high-strength and/or overly hardened materials have been installed in humid environments and subjected to high, sustained tensile stresses. Contaminants, such as those from lubricants, may also be a contributing factor. Most of stress corrosion cracking failures in the industry involving bolting were due to fabrication issues and were identified prior to commercial operation. No McGuire or Catawba operating experience exists to suggest stress corrosion cracking is a concern for license renewal, and no specific program is required.

On the basis of its review of the RAI response pertaining to high-strength structural bolting, the staff finds that all applicable aging effects were identified, and the aging effects identified are appropriate for the combination of materials and environments identified.

*3.5.4.2 Aging Management Programs*

Loss of material of structural components including the bolting is managed by the Inservice Inspection Plan — Subsection IWF and the Inspection Program for Civil Engineering Structures and Components. Indications of potential problems would be noted through visual inspection of coating integrity and obvious signs of loss of material such as corrosion, rust, etc. Loss of material of these components is addressed through the Inservice Inspection Plan — Subsection

IWF or the Inspection Program for Civil Engineering Structures and Components. The Inservice Inspection Plan — Subsection IWF and the Inspection Program for Civil Engineering Structures and Components are described in Appendix B, Sections B.3.20.2 and B.3.21, respectively, of the LRA. The inspection of the structural bolting for degradation would be included with the component.

The Inservice Inspection Plan — Subsection IWF program and the Inspection Program for Civil Engineering Structures are considered common AMPs. The staff has evaluated these common AMPs and found them to be acceptable for managing the aging effects identified for high-strength structural bolting. The staff's evaluation of these AMPs is documented in Section 3.0 of this SER.

*3.5.4.3 Conclusions*

Based on the above discussion, the staff finds that the applicant's response clarifies and satisfactorily resolves this issue concerning the structural bolting as described in RAI 3.2-1. The staff concludes that the applicant has demonstrated that the aging effects associated with high-strength structural bolting will be adequately managed so there is reasonable assurance that these components will perform their intended functions consistent with the CLB throughout the period of extended operation, as required by 10 CFR 54.21(a)(3).

## 3.6 Aging Management of Electrical and Instrumentation and Controls Components

The applicant described its AMR of electrical and instrumentation and controls components requiring AMR in Section 3.6 of the LRA. The AMR for all non-EQ insulated cables and connections is generically applicable to both McGuire and Catawba. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging for the electrical and instrumentation and controls components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The applicant based its review on industry literature, plant operating experience, and lessons learned from previous reviews performed for license renewal. Aging effects caused by heat and radiation, moisture and voltage stress of medium-voltage cables, and boric acid ingress into connector pins are included in the AMR of non-EQ insulated cables and connections. Details of aging effects are provided in Table 3.6-1, on page 3.6-1, of the LRA.

### 3.6.1 Aging Effects Caused by Heat and Radiation

*3.6.1.1 Technical Information in the Application*

In Section 3.6.1 of the LRA, the applicant described the process it used to identify the applicable aging effects of the electrical and instrumentation and controls components. The applicant used a bounding “plant spaces” approach to determine the required aging management program and activities that will manage aging effects caused by heat and radiation such that the intended function of non-EQ insulated cables and connections is maintained consistent with the current licensing basis for the period of extended operation.

The cable and connection material of interest for the aging management review is the primary conductor insulating material. Using the “plant spaces” approach, aging of installed cables and connections is bounded by the cable and connection insulation materials that are specified in the aging management review. The 60-year service-limiting temperature and 60-year service-limiting radiation dose for the bounding insulation materials are listed in Table 3.6-2, on page 3.6-2, of the LRA.

The review of aging effects caused by heat and radiation includes the identification of the service conditions for insulated cables and connections. Service conditions include the ambient temperature with ohmic heat for power applications. The service conditions for non-EQ insulated cable and connections are listed in Table 3.6-3, page 3.6-2, of the LRA. The service conditions identified in Table 3.6-3 are bounding values. These bounding values are greater than the actual values for most plant areas due to factors such as daily and seasonal temperature fluctuations and unit outages.

In LRA Table 3.6-4, the applicant compares the service conditions to insulation material 60-year service-limiting temperature and radiation dose for the bounding insulation materials. The results of the comparison are provided in the right-hand column of LRA Table 3.6-4 and are discussed below.

There are plant areas where the bounding service conditions are greater than the 60-year service-limiting temperature or radiation dose; these are identified with a “No” in the right-hand column of Table 3.6-4, page 3.6-3, of the LRA. This signifies that some insulation materials are not suited for the bounding service conditions for 60 years of service. Based on this finding, the applicant chose not to define the service conditions for specific plant areas. Instead, the applicant will require aging management to manage the aging effects so that it can demonstrate a reasonable assurance that the intended functions of non-EQ insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation. A new program, “The Non-EQ Insulated Cables and Connections Aging Management Program,” will be implemented to demonstrate this reasonable assurance. The non-EQ insulated cables and connections within the scope of this program include non-EQ cables used in low-level signal monitoring and nuclear instrumentation.

3.6.1.1.1 Aging Effects

Table 3.6-1 of the LRA identifies the following aging effects for non-EQ insulated cables and connections caused by heat and radiation:

- embrittlement
- cracking
- melting
- discoloration
- swelling

3.6.1.1.2 Aging Management Program

Table 3.6-5 of the LRA credits the Non-EQ Insulated Cables and Connections Aging Management Program to manage the identified aging effects for insulation materials. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation will be adequately managed by this AMP such that there is reasonable assurance that accessible non-EQ insulated cables and connections will perform their intended function in accordance with the current licensing basis during the period of extended operation.

*3.6.1.2 Staff Evaluation*

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s aging management program credited for the aging management of insulated cables and connections at McGuire and Catawba nuclear stations. The staff’s evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on cables will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.1.2.1 Aging Effects

In most areas within a nuclear power plant, the actual ambient environment (e.g., temperature, radiation, or moisture) is less severe than the plant design environment. However, in a limited number of localized areas, the actual environments may be more severe than the plant design environment. Conductor insulation materials used in cables and connections may degrade more rapidly than expected in the adverse localized environments. An adverse localized environment is limited to a certain plant area with significantly more severe conditions than the specific service condition for the cable. An adverse variation in environment is significant if it could appreciably increase the rate of aging of a component or have an immediate adverse effect on operability.

Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and decrease in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, melting, discoloration, and swelling of the jacket and insulation. Radiation-induced degradation in cable jacket and insulated materials produces change in organic material properties, including reduced elongation and tensile strength. Visible indication of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation material.

The applicant identified embrittlement, cracking, melting, discoloration, and swelling as applicable aging effects for the insulated cables and connections. The staff concurs with the aging effects identified above by the applicant for the insulated cables and connections.

In a letter dated May 16, 2002, the staff forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists a proposed interim staff guidance (ISG) document on screening of electrical fuse holders. The ISG stated that fuse holders should be scoped, screened, and subject to an AMR in the same manner as terminal blocks and other types of electrical connections that also meet the criteria specified in 10 CFR 54.4 and 54.21. This position applies only to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered piece-parts of the larger assembly and not subject to an AMR.

The intended functions of a fuse holder are to provide mechanical support for the fuse and to maintain electrical contact with the fuse blades or metal end caps to prevent the disruption of the current path during normal operating conditions when the circuit current is at or below the current rating of the fuse. Like electrical connections, fuse holders perform a primary function of providing electrical connections to specified sections of an electrical circuit to deliver rated voltage, current, or signals. These intended functions of fuse holders meet the criteria of 10 CFR 54.4(a). In addition, these intended functions are performed without moving parts and without a change in configuration or properties as described in 10 CFR 54.21(a)(1)(i). The fuse holders into which fuses are placed are typically constructed of blocks of rigid insulating material, such as phenolic resins. Metallic clamps are attached to the blocks to hold each end of the fuse. The clamps can be spring-loaded clips that allow the fuse ferrules or blades to slip in, or they can be bolt lugs to which the fuse ends are bolted. The clamps are typically made of copper.

Operating experience as documented in NUREG-1760, “Aging Assessment of Safety-Related Fuses Used in Low- and Medium-Voltage Applications in Nuclear Power Plants,” indicates that aging stressors such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, or oxidation of the connection surfaces can result in fuse holder failure. The final staff position on this issue is under development. In a letter dater November 13, 2002, the staff requested the applicant to commit to implement, at McGuire and Catawba, the final resolution of the ISG.

In its response to the staff's request, dated November 18, 2002, the applicant provided the following commitment:

> For McGuire, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by June 12, 2021 (the end of the initial license of McGuire Unit 1).
>
> For Catawba, Duke commits to implement the final version of the fuse holder interim staff guidance (initially provided to NEI by letter dated May 16, 2002 and when finalized by the staff) by December 6, 2024 (the end of the initial license of Catawba Unit 1).

This commitment was included in a table of commitments submitted by the applicant in a letter dated December 16, 2002. The table of commitments is provided in Appendix D of this SER. The staff found the applicant's response acceptable because it commits to implement the final resolution of the ISG before the period of extended operation begins at McGuire and Catawba.

3.6.1.2.2 Aging Management Programs

The applicant identified the Non-EQ Insulated Cables and Connections Aging Management Program to manage the aging effects of accessible non-EQ insulated cables and connections caused by heat or radiation. The applicant describes this program in Appendix B of the LRA, Section B.3.23, "Non-EQ Insulated Cables and Connections Aging Management Program."

<u>Non-EQ Insulated Cables and Connections Aging Management Program</u>

The staff's evaluation of the applicant's AMP focused on the program elements rather than details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) program scope, (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, and (10) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining seven elements follows.

[Program Scope] The applicant states that the scope of the Non-EQ Insulated Cables and Connections Aging Management Program includes accessible (able to be approached and viewed easily) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirements) insulated electrical cables and connections (power, instrumentation, and control applications) installed in the reactor buildings, auxiliary building, and turbine building. The non-EQ insulated cables and connections within the scope of this program include non-EQ cables used in low-level signal applications that are sensitive to reduction in insulation resistance, such as radiation monitoring and nuclear instrumentation. The staff finds that, with the exception of low-level instrumentation circuits, the scope of the program is acceptable because it includes all non-EQ insulated cables and connections that are subject to a potentially adverse localized environment of heat or radiation that could cause applicable aging effects in these insulated cables and connections. The staff's evaluation of this program for low-level instrumentation circuits is documented later in this section (see section titled "Low-level Instrumentation Circuits").

[Preventive Actions]  The applicant states that no actions are taken as part of the Non-EQ Insulated Cables and Connections Aging Management Program to prevent or mitigate aging degradation, and the staff did not identify the need for such actions.

[Parameters Monitored or Inspected]  The applicant states that accessible non-EQ insulated cables and connections installed in the reactor buildings, auxiliary building, and turbine building are visually inspected (per the Non-EQ Insulated Cables and Connections Aging Management Program) for cable and connection jacket surface anomalies such as embrittlement, discoloration, cracking, or surface contamination.  Cable and connection jacket surface anomalies are precursors indicative of conductor insulation aging degradation from heat or radiation in the presence of oxygen and may indicate the existence of an adverse localized equipment environment.  An adverse localized equipment environment is a condition in a limited plant area that is significantly more severe than the specified service condition for the insulated cable or connection.   The staff finds the inspection approach acceptable because it provides a means for monitoring the applicable aging effects for accessible in-scope non-EQ insulated cables and connections.

[Detection of Aging Effects]  The application states that the Non-EQ Insulated Cables and Connections Aging Management Program will detect aging effects for accessible non-EQ insulated cables and connections caused by heat and radiation prior to loss of intended function.  The staff finds the inspection scope and inspection technique acceptable on the basis that the AMP is focused on detecting change in material properties of the insulation.  Change in material property of the insulation is the applicable aging effect when cables and connections are exposed to an adverse localized environment.

[Monitoring and Trending]  The applicant states that accessible non-EQ insulated cables and connections installed in the reactor building, auxiliary building, and turbine building are visually inspected per the Non-EQ Insulated Cables and Connections Aging Management Program at least once every 10 years.  EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environment," is used as guidance in performing the inspections.  Trending actions are not required as part of the Non-EQ Insulation Cables and Connection Aging Management Program.  The staff found the absence of a trending program acceptable since the inspection is performed every 10 years and, therefore, is not conducive to trending.

For McGuire, the first inspection (per the Non-EQ Insulated Cables and Connections Aging Management Program) will be completed following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license for McGuire 1).  For Catawba, the first inspection (per the Non-EQ Insulated Cables and Connections Aging Management Program) will be completed following issuance of renewed operating licenses for Catawba and by December 6, 2024 (the end of the initial license for Catawba 1).  The staff finds that a 10-year inspection frequency is an adequate period to preclude failures of the conductor insulation since aging degradation is a slow process.  A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate.  The visual technique is acceptable because it provides an indicator that can be visually monitored to identify aging effects of accessible cables and connections and includes inaccessible cables and connections in its corrective actions.

[Acceptance Criteria]  The acceptance criteria for inspection performed per the Non-EQ Insulated Cables and Connections Aging Management Program are no unacceptable visual indications of cable and connection jacket surface anomalies that suggest conductor insulation degradation exists, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff finds the acceptance criteria acceptable because they should ensure that the cables and connections intended functions are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] The applicant states that the Non-EQ Insulated Cables and Connections Aging Management Program is a new program for which there is no operating experience. However, operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within 3 feet of) steam generators, pressurizers or hot process pipes such as feedwater lines. The staff finds that the proposed inspection program will detect the adverse localized environment caused by heat or radiation of electrical cables and connections.

FSAR Supplement: The staff has reviewed the UFSAR supplement in Sections 18.2.19 and 18.2.18 of the LRA for McGuire (Appendix A-1) and Catawba (Appendix A-2), respectively. The staff confirmed that the information provided in the FSAR supplements addresses the applicable elements of the programs for non-EQ insulated cables and connections. However, the staff notes that the FSAR supplement does not address low-level instrumentation circuits, which are discussed in the following section. Therefore, the FSAR supplements are acceptable for non-EQ cables except for those non-EQ cables in low-level instrumentation circuits as discussed below.

<u>Low-Level Instrumentation Circuits</u>

The aging management activity submitted by the applicant does not utilize the calibration approach for non-EQ electrical cables used in circuits with sensitive, low-level signals. Instead, these cables are simply combined with all other non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone would not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to localized environments caused by heat or radiation can result in reduced IR. Reduced IR causes an increase in leakage currents between conductors and from individual conductors to ground. A reduction in IR is a concern for circuits with sensitive, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument loop.

The staff is not convinced that aging of these cables will initially occur on the outer casing, resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss of the cables' intended function, particularly if the cables are also subject to moisture. Therefore, by letter dated January 17, 2002, the staff requested, in RAI 3.6.1-1, the applicant to provide a technical justification that will demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy.

In its response dated March 8, 2002, the applicant reiterated the view that for low-voltage cables, embrittlement and significant cracking (through cracks) of the cable jacket and conductor insulation would have to occur before the introduction of moisture around the cable could be an issue. The applicant stated that, having performed extensive, plant-wide visual inspection as part of license renewal preparatory work at Oconee, Duke has a very high confidence that the visual inspection will detect early degradation of insulation of all types of cables and connections including those that are the subject of the staff's RAI. The applicant also stated that the Sandia Report (SAND) 96-0344[9] provides an evaluation of aging and aging management for cables and connections. SAND 96-0344, Section 5.2.2, "Measurement of Component or Circuit Properties," states that diagnostic techniques to assist in the assessment of the functionality and condition of power plant cables and termination are described as follows:

> Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal-and radiation-induced aging. For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed...

"Embrittlement and cracking" are signs of extensive aging that are easily detectable by visual inspection. Signs of less extensive aging, such as discoloration, are also easily detectable by visual inspection. Visual inspection can detect aging degradation early in the aging process before significant aging degradation has occurred. SAND 96-0344, Section 5.2.2.1.2, "Insulation Resistance (IR) — Advantages/Disadvantages," provides further information on insulation resistance as an electrical property related to aging of cables as follows:

> IR may give some indication of the aging of connections, however, it is generally considered of little use in predicting the aging of a cable. IR properties of dielectrics may change little until severe degradation of mechanical properties occurs. These measurements display some gradual changes with aging, but are generally nowhere near as sensitive to aging as techniques based on mechanical properties....Conversely, even gross insulation damage may not be evidenced by changes in IR; for example, an insulation cut-through surrounded by dry air may not significantly affect IR readings... Testing is usually conducted as a pass/fail...

Having reviewed the applicant's response, the staff undertook its own review of several aging management references. Page 3-5 of the SAND 96-0344 report referenced by the applicant identified polyethylene insulated instrumentation cables located in close proximity to fluorescent lighting that had developed spontaneous circumferential cracks in exposed portions of the insulation. For some of the affected cables, the cracking was severe enough to expose the underlying conductor; however, no operational failures were documented as a result of this degradation.

Section 5.2.2 of the SAND 96-0344 report referred to by the applicant assumes only dry conditions where cable cracking occurs. V.N. Shah and P.E. MacDonald, on page 855 of "Aging and Life Extension of Major Light Water Reactor Components,"[10] state that breaks in insulation systems that are dry and clear are normally not detectable with insulation resistance tests of 1000 volts or less. Insulation resistance tests can detect some types of gross insulation

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[9] Sandia Contractor Report SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations," prepared by Ogden Environmental and Energy Services, Inc., printed September 1996

[10] "Aging and Life Extension of Major Light Water Reactor Components," edited by V.N. Shah and P.E. MacDonald, 1993, Elsevier Science Publishers

damage, cracking of insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive.

Electric Power Research report EPRI TR-103834-P1-2 also supports the above view. It states on page 1.4-8 that normal or high insulation resistance may not indicate undamaged insulation in that a through-wall cut or gouge filled with dry air may not significantly affect the insulation resistance. The SAND 96-0344 report, on page 3-51, states that instances of low-voltage cable and wire shorting to ground induced by moisture may, in fact, be due to moisture intrusion through preexisting cracking, an effect of thermal and/or radiation exposure.

In summary, it appears from this literature and the applicant's response to the staff's RAI that visual inspection of low-voltage, low-signal-level instrumentation circuits can be an effective means to detect age-related degradation due to adverse localized environments. Because a moisture environment can apparently hasten the failure of these circuits if they have previously undergone age-related degradation, the disposition of a degraded cable should consider the potential for moisture in the area of the degradation.

In a letter dated July 9, 2002, the applicant agreed to add the following statement to the Corrective Actions & Confirmation Process of the Non-EQ Insulated Cables and Connections Aging Management Program: "[The program] should consider the potential for moisture in the area of degradation." The staff found this change to the Corrective Actions and Confirmation Process element of the Non-EQ Insulated Cables and Connections Aging Management Program acceptable since the applicant agreed to address the potential for moisture-induced signal degradation or failure. The staff noted that the FSAR supplement needed to be updated to reflect this change and characterized this issue as confirmatory item 3.6.1-1.

In its response to confirmatory item 3.6.1-1, dated October 2, 2002, the applicant stated that it will add the following statement to the Corrective Actions and Confirmation Process of the Non-EQ Insulated Cables and Connections Aging Management Program summary description contained in Chapter 18 of each station's FSAR supplement: "Corrective action should consider the potential for moisture in the area of degradation."

The staff found the applicant's response to confirmatory item 3.6.1-1 acceptable because the modification to the Non-EQ Insulated Cable and Connections Aging Management Program is reflected in the revised FSAR supplement.

The staff noted that the above finding on low-voltage instrumentation circuits is not necessarily the case for high-range radiation monitor and neutron monitoring system cables. The SAND 96-0344 report referenced by the applicant states on page 3-36 that neutron monitoring systems (including source, intermediate, and power range monitors) were separated into their own category based on (1) their substantial difference from typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of reports related to these devices and identified in the database. The report states that neutron detectors are frequently energized at what is commonly referred to as "high" voltage, usually between 1 and 5 kV. This is not high voltage in the sense of power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The report included the lower voltage non-detection portion of typical neutron monitoring equipment in the low-voltage equipment category, but separated out the 1 to 5 kV neutron detectors into a separate category that included neutron monitor cables and connectors.

The high-voltage portion of the neutron monitoring systems would appear to be a worst-case subset of the low-signal-level instrumentation circuit category. These circuits operate with low-level logarithmic signals that are sensitive to relatively small changes in signal strength, and they operate at a high voltage which could create larger leakage currents if that voltage is impressed across associated cables and connections. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, Supplement 1, describes this phenomenon. The neutron monitoring circuits and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily for the visual inspection approach.

The staff indicated that the applicant should provide a technical justification to demonstrate that visual inspection will be effective in detecting damage to high-range radiation monitor and neutron monitoring instrumentation cables before current leakage can affect instrument loop accuracy. This issue was characterized as SER open item 3.6.1-1.

In its response to open item 3.6.1-1, dated October 2, 2002, the applicant reiterated its view that visual inspections have proven to be effective and useful because visual inspections have revealed potential problems. The applicant asserted that problems that have not developed to the point of component failure can be identified through visual inspection. The applicant also stated that mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed. Embrittlement and cracking are signs of extensive aging that are easily detectable by visual inspection. Signs of less extensive aging, such as discoloration, also are easily detectable by visual inspection. Visual inspection can detect aging degradation early in the aging process before significant aging degradation or failure has occurred.

The applicant provided three examples of cable installation configuration that were identified through visual inspection that would not have been otherwise identified. In one example, the applicant stated that, during Oconee visual inspection walkdowns, the power and control cables for an auxiliary steam (AS) system valve were found lying on top of an uninsulated portion of the pipe. Contact with the hot steam pipe eventually would have degraded the cables, potentially resulting in failure. The valve was installed near the ceiling in the turbine building, some 30 feet above the floor, and would have been found only through dedicated visual inspections. In another example, the applicant stated that a visual inspection walkdown also revealed a small cable tray with safety-related cables that were installed near the ceiling in close proximity to a high-intensity light fixture. The applicant had identified a concentric ring on the bottom of the cables. At the time this was identified, the applicant could not determine if the rings were cast by variations in the light shining on the cables or if heat generated from the lamp had discolored the cable jackets. In a third example, the applicant had identified (during an Oconee walkdown) instrumentation cables in a cable tray in the reactor building that was installed directly over a feedwater line. The heat escaping from a shield wall penetration sleeve around the feedwater pipe was accelerating the aging of the cable insulation. The visual signs that indicated aging degradation of cables in the tray were the way the cables “sagged” between the cable tray lattice. The applicant also stated that many of the cable jackets looked “dry” and had surface cracks. The cables in the tray were tested, and all cables were fully functional.

As previously discussed, the staff agreed with the applicant that, for low-voltage, low-signal cables, visual inspection can be an effective means to detect age-related degradation due to adverse localized environments. However, the staff does not believe that this is necessarily the case for high-range radiation monitor and neutron monitoring system cables. These circuits operate with low-level logarithmic signals that are sensitive to relatively small changes in signal strength, and they operate at high voltages that could create larger leakage currents if the voltage is impressed across associated cables and connections. The staff did not have reasonable assurance that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy. Therefore, the staff issued a letter dated November 13, 2002, to notify the applicant that open item 3.6.1-1 remained unresolved. The proposed visual inspection was not consistent with the staff's position on previous LRA reviews. However, loop calibration tests, which are routinely performed in accordance with existing technical specification surveillance requirements at McGuire and Catawba, might be considered acceptable for monitoring aging of cables during the period of extended operation and involve minimal regulatory burden.

In its response dated November 14, 2002, the applicant stated that it will implement the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits specifically to address the staff's open item 3.6.1-1. The scope of this program included only non-EQ neutron flux instrumentation cables that are within the scope of license renewal. The applicant indicated that other cables under discussion here, high-range radiation monitors/cables and the wide-range neutron flux monitors/cables, were included in the McGuire and Catawba EQ program and already covered for license renewal by this program. After reviewing the License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits, the staff contacted the applicant by phone and requested the applicant to indicate whether or not the high-range radiation monitoring cables were included within the scope of this program. During the call, the applicant indicated that it had included only the cables used in non-EQ neutron flux instrumentation circuits within the scope of 10 CFR 54.4. Non-EQ means not subject to 10 CFR 50.49 EQ requirements. The applicant stated that it excluded the high-range radiation monitors/cables and the wide-range neutron flux monitors/cables from the scope of the AMP because they are included in the EQ program. However, the staff noted that these cables are run inside and outside containment, and that the portions of the cables that are outside the containment are non-EQ and should be included in the scope of the AMP.

In a letter dated November 21, 2002, the applicant indicated that, since the scope of this program did not include the high-range radiation monitoring cables, a different program had been developed. The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits was provided in place of its License Renewal Program for Non-EQ Neutron Flux Instrumentation Circuits. The applicant indicated that the November 21, 2002, response superceded the November 14, 2002, response. The staff found the applicant's November 21, 2002, response to SER open item 3.6.1-1 acceptable because the applicant will implement an AMP to monitor the aging of these sensitive cables. Therefore, open item 3.6.1-1 is closed.

The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits was evaluated by the staff to establish reasonable assurance that the intended function of electrical cables that are (1) not subject to the EQ requirement of 10 CFR 50.49, and (2) are used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation.

<u>License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits</u>. The License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits is generically applicable to both McGuire and Catawba, except as otherwise noted. The staff's evaluation of the applicant's AMP focused on the program elements rather than details of specific plant procedures. To determine whether the applicant's aging management program is adequate to manage the effects of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (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 action, (8) confirmation process, (9) administrative controls, and (10) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining elements follows.

[Program Scope] In its letter dated November 21, 2002, the applicant described the scope of the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits as follows:

> [Scope] The scope includes the non-EQ cables used in neutron flux instrumentation circuits and high-range radiation instrumentation circuits within the scope of 10 CFR 54.4. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements.

The staff found the applicant's scope attribute description acceptable because the scope specifically includes the high-range radiation monitoring and wide-range neutron flux cables that are outside the containment.

[Preventive Actions] No actions are taken as part of the License Renewal Program for High-Range Radiation and Neutron Flux Instrumentation Circuits to prevent aging effects or to mitigate aging degradation, and the staff did not identify the need for such actions.

[Parameters Monitored or Inspected] The parameters monitored are determined from the plant technical specification and are specific to each instrumentation circuit, as documented in surveillance procedures. The staff found this approach to be acceptable because it provides means for monitoring the applicable aging effects for in-scope instrumentation cables.

[Detection of Aging Effects] In accordance with the information provided in Monitoring and Trending, the License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits provides sufficient indication of the need for corrective actions. The staff found it acceptable on the basis that the calibration program identifies the need for corrective actions by monitoring key parameters based on acceptance criteria.

[Monitoring and Trending] The methods for performing the License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits are described in Sections 3.3.1 and 3.3.3 of each station's TS. Instrumentation circuit surveillances currently required by plant TS are performed at the specified surveillance frequency and provide sufficient indication of the need for corrective actions based on acceptance criteria related to instrumentation circuit performance. Trending actions are not included as part of this program because the ability to trend test results is dependent on the specific type of test chosen. Although not a requirement, test results that can be trended will provide additional information about the rate of degradation.

The staff found that the normal surveillance frequency specified in the plant TS provides reasonable assurance that aging degradation of high-range radiation and neutron flux instrumentation circuits will be detected before a loss of their intended functions occurs. The staff also found the absence of trending acceptable; however, the staff notes that trending should be performed by the applicant when the specific type of test makes this possible because it provides additional information about the condition of the cables.

[Acceptance Criteria] The acceptance criteria for each surveillance are documented in surveillance procedures. The staff found the acceptance criteria acceptable because the surveillance procedures are used to demonstrate that surveillance requirements specified in ITS 3.3.1 and 3.3.3 are met. The activities described in the McGuire and Catawba TS should ensure that intended functions of the cables used in instrumentation circuits are maintained under all CLB design conditions during the period of extended operation.

[Operating Experience] Plant-specific and industry operating experience have shown that adverse circuit indications found during routine surveillance can be caused by degradation of the instrumentation circuit cable and are possible indications of potential cable degradation. The staff found it acceptable because the calibration program will detect the aging degradation of instrumentation circuit cables that are installed in the adverse localized environments.

FSAR Supplement. In its November 21, 2002, response to SER open item 3.6.1-1, the applicant stated that it would revise the Table 18-1 of each station's UFSAR to insert the following item:

| Topic | Application Location | UFSAR/ITS |
|---|---|---|
| License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits | NA | ITS 3.3.1<br>ITS 3.3.3 |

The staff found the proposed FSAR supplement acceptable because ITS 3.3.1 and 3.3.3 provide appropriate acceptance criteria, surveillance frequency, and test objectives for the AMP. The level of detail provided in the ITS is equivalent to that which is specified in the staff's review guidance (NUREG-1800) and, therefore, is an adequate summary of the program activities as required by 10 CFR 54.21(d).

On the basis of its review, the staff found that the program established reasonable assurance that the intended function of electrical cables that are (1) not subject to the EQ requirement of 10 CFR 50.49, and (2) are used in circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation.

*3.6.1.3 Conclusions*

Based on the review of the LRA and the applicant's responses to the staff's RAI and SER open and confirmatory items, the staff concludes that the implementation of Non-EQ Insulated Cables and Connections Aging Management Program and License Renewal Program for High-range Radiation and Neutron Flux Instrumentation Circuits will provide reasonable assurance that the aging effects associated with heat, radiation, and moisture for insulated cables and connections will be managed. This program will provide reasonable assurance that the intended functions of electrical cables and connections will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.6.2 Aging Effects Caused by Moisture and Voltage Stress for Inaccessible Medium-Voltage Cables

*3.6.2.1 Technical Information in the Application*

In Section 3.6.2 of the LRA, the applicant described the aging effects caused by moisture and voltage stress for inaccessible medium-voltage cables.

3.6.2.1.1 Aging Effects

The applicant states that it has identified aging effects caused by moisture and voltage stress as potential aging effects for inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirements) medium-voltage cables that are exposed to significant moisture while energized. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that last for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Medium-voltage cables routed in conduit at Catawba are not a concern due to the design criterion documented in UFSAR Section 8.3.1.4.5.1, “Cable Installation,” that conduit runs are sloped for drainage. In addition to being exposed to long-term continuous standing water and voltage stress, inaccessible non-EQ medium-voltage cables must normally be energized more than 25 percent of the time in order to be susceptible to electrical degradation. The applicant also states that the two criteria identified above are conservative and are used only as threshold values for an inaccessible non-EQ medium-voltage cable to be identified as susceptible to aging effects caused by moisture and voltage stress. A qualifier to these two criteria is that if an inaccessible non-EQ medium-voltage cable is designed for or specified for the conditions described in these two criteria, then the cable is not considered susceptible to aging effects caused by moisture and voltage stress.

3.6.2.1.2 Aging Management Programs

Table 3.6-5 of the LRA credits the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program for managing the identified aging effects for inaccessible non-EQ medium-voltage cables. A description of this AMP is provided in Appendix B of the LRA. The applicant concludes that this program will provide reasonable assurance that the intended functions of inaccessible medium-voltage cables will be maintained consistent with the CLB through the period of extended operation.

*3.6.2.2 Staff Evaluation*

This section of the SER provides the staff’s evaluation of the applicant’s aging management review for aging effects and the applicant’s aging management program credited for the aging management of inaccessible non-EQ medium voltage cables at McGuire and Catawba. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on cables will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.1 Aging Effects

Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to condensation and wetting in inaccessible locations, such as conduits, cable trenches, cable troughs, duct banks, underground vaults, or direct buried installations. When an energized cable not specifically designed for submergence is exposed to these conditions, water treeing or a decrease in the dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. The growth and propagation of water trees is somewhat unpredictable and occurrences have been noted for cable operated below 15 kV. Water treeing is a long-term degradation and failure phenomenon that is documented only for medium-voltage electrical cables.

The applicant identified formation of water trees and localized damage as applicable aging effects for the inaccessible non-EQ medium-voltage cables caused by moisture and voltage stress. The staff concurs with the aging effects identified above by the applicant for inaccessible medium-voltage cables.

3.6.2.2.2 Aging Management Program

The staff's evaluation of the applicant's AMP focused on the program element rather than details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (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 action, (8) confirmation process, (9) administrative controls, and (10) operating experience. The staff's evaluation of the elements for corrective action, confirmation process, and administrative controls is documented in Section 3.0.4 of this SER. The staff's evaluation of the remaining elements follows.

[Program Scope] In the previous AMP, the scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible (for example, in conduit or direct buried) non-EQ (not subject to 10 CFR 50.49 Environmental Qualification requirement) medium-voltage cables that are exposed to significant moisture with significant voltage. Significant moisture is defined by the applicant as exposure to long-term (over a long period such as a few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture that last for short periods are not significant (i.e., rain and drain exposure that is normal to yard cable trenches). Significant voltage exposure is defined as being subjected to system voltage for more than 25 percent of the time. The moisture and voltage exposures described as significant in these conditions are not significant for medium-voltage cable that are designed for these conditions (e.g., continuous wetting and continuous energization are not significant for submarine cables).

It was not clear to the staff that exposure of inaccessible medium-voltage cables to moisture for a period of “a few years” is not significant. By letter dated January 17, 2002, the staff requested, in RAI B.3.19-2, the applicant to explain why exposure to moisture over more than a few days, and up to a few years, is not significant. In response to the staff request, in a letter dated April 15, 2002, the applicant states that based on a review of industry literature on the topic of medium-voltage cables being exposed to moisture for long periods, no quantifiable data were found in the documents. However, the data and discussion in this industry literature (for example, EPRI TR-103834-P1-2, “Effects of Moisture on the Life of Power Plant Cables,” and SAND 96-0344, “Aging Management Guideline for Commercial Nuclear Power Plants — Electrical Cables and Termination”) provide the general conclusion that there should not be a problem with a medium-voltage cable even if it is exposed to moisture for several years.

The staff noted that the applicant’s reference (SAND 96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Termination) states the following in Section 4.1.2.4:

> Note, however, that even minor and/or intermittent surface condensation, in conjunction with voltage stress and contaminants, may create an environment where surface tracking may occur. Furthermore, some evidence exists to indicate that the rate of diffusion of water through a polymer is relatively independent of form [4.38]. Therefore, the water diffusion rate for a “dry” material in a 100 percent RH atmosphere may not be different than that for the same material completely submerged in water.

It was not clear to the staff that inaccessible cables exposed to moisture for a period of “a few years” was not significant. The applicant’s response did not resolve the issue of cables exposed to wet conditions for which they are not designed.

By letter dated July 9, 2002, the applicant provided the following statement to resolve this issue:

> Duke agrees with the staff on this point. To resolve this item, Duke has eliminated the qualifier “significant” when describing moisture with regards to the program. The program now takes a bounding approach by stating, “Cables that are direct buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water.” In-scope medium-voltage cables that are exposed to standing water and also exposed to significant voltage will be tested.

As a result of eliminating the qualifier “significant” when describing moisture in the programs, the applicant proposes to revise the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program attributes to the following:

> Scope – The scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage and to standing water (for any period of time).
>
> Key Definitions and Assumptions: Inaccessible cables are those that are not able to be approached and viewed easily, such as in conduits or cable trenches; all others are accessible. A cable that has a portion of the cable routing that is inaccessible is an inaccessible cable. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than 2kV. Significant voltage is defined as exposure to system voltage for more than twenty-five percent of the time. Cables that are direct buried, run in horizontally-run buried conduit or run in outside cable trenches are assumed to be exposed to standing water.

Preventive Actions – Preventive actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

Parameters Monitored or Inspected – Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested to provide an indication of the condition of the conductor insulation. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test.

Detection of Aging Effects – Medium-voltage cables within the scope of the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are tested at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation.

Monitoring and Trending – Trending actions are not included in the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*.

For McGuire, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* 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, the first test per the *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* 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).

Acceptance Criteria – The acceptance criteria for each test is defined by the specific type of test performed and the specific cable tested.

Corrective Actions & Confirmation Process – Further investigation through the corrective action program is performed when the acceptance criteria are not met. When an unacceptable condition or situation is identified, a determination is made as to whether the same condition or situation is applicable to other medium-voltage cables within the scope of this program. Confirmatory actions, as needed, are implemented as part of the corrective action process.

Administrative Controls – The *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* is controlled by plant procedures.

Operating Experience – Operating experience is not relevant for this new program.

The staff finds that the scope of the revised program is acceptable since the applicant has agreed to eliminate the qualifier “significant” when describing cables that are exposed to moisture and this issue is resolved. The staff evaluated the applicant’s revised attributes for Parameters Monitored or Inspected, Detection of Aging Effects, Acceptance Criteria, and Corrective Action and Confirmation Process, and documented its evaluation in the applicable paragraphs that follow in this SER section. The other attributes were not affected by the revisions to this program. Therefore, the staff evaluated these attributes as they were described in the LRA. The staff notes that the FSAR supplement should be revised to reflect the change in the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program, as discussed in its evaluation of the FSAR supplement below.

[Preventive Actions] In the previous AMP, the applicant stated that no preventive actions are required as part of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program. Periodic actions may be taken to prevent inaccessible non-EQ medium-voltage cables from being exposed to significant moisture such as inspecting for water collection in cable manholes and conduit and draining water as needed. Testing of a cable per this program is not required when such preventive actions are taken since the significant moisture criteria defined under Program Scope would not be met.

Periodic actions should be taken to prevent cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water as needed. Medium-voltage cables for which such actions are taken are not required to be tested. By letter dated January 17, 2002, the staff requested the applicant in RAI B.3.19-1 to explain why no preventive actions were specified as part of its AMP. In its response dated April 15, 2002, the applicant stated that the McGuire and Catawba proposed program for medium-voltage cable is written specifically for "inaccessible medium-voltage cables, i.e., cables that cannot be accessed." In a long cable run in a conduit or concrete trench or direct buried, most of the length is inaccessible, which means that most of the cable length is not accessible for inspection to determine if it is exposed to significant moisture. If any portion of a medium-voltage cable along its entire run is inaccessible and could be subject to significant moisture exposure, that cable would be identified as inaccessible and possibly subject to testing per the McGuire and Catawba program. The McGuire and Catawba program for medium-voltage cable was not written for accessible medium-voltage cables. During the review performed to respond to the staff's RAI, it was realized that there may be cases where it is practical to perform periodic actions to limit exposure of medium-voltage cables to moisture and, thus, mitigate any aging effects. These actions, such as inspecting cable manholes for water collection, would mainly cover the accessible portions of these cables that may provide symptomatic evidence of the conditions to which other portions of the cable are exposed. Based on the review performed to respond to the staff's RAI, the applicant would change the program descriptions contained in McGuire FSAR supplement 18.2.15 and Catawba FSAR supplement 18.2.14 by replacing existing text with the following text in the Scope, Preventive Actions and Monitoring and Trending program attributes:

> [Scope] The scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program includes inaccessible non-EQ medium-voltage cables within the scope of 10 CFR 54.4 that are exposed to significant voltage simultaneously with significant moisture.
>
> Key Definition and Assumptions: Inaccessible cables are those that are not able to be approached and viewed easily, such as in conduits or cable trenches; all other are accessible. Non-EQ means not subject to 10 CFR 50.49 Environmental Qualification requirements. Medium-voltage cables are those applied at a system voltage greater than 2kV and less than 15kV. Significant voltage is defined as exposure to system voltage for more than 25 percent of the time. Significant moisture is defined as exposure to long-term (over a long period such as few years), continuous (going on or extending without interruption or break) standing water. Periodic exposures to moisture for shorter periods are not significant (for example, rain and drain exposure that is normal to yard cable trenches). Significant moisture is assumed to be present unless engineering data indicates otherwise. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions (for example, continuous wetting and continuous energization is not significant for submarine cables).
>
> [Preventive Actions] Periodic actions are taken where practical, as determined by the accountable engineer, to mitigate any aging effects by limiting the exposure of inaccessible non-EQ medium-voltage cables to moisture, such as inspecting for water collection in cable manholes and conduits and draining water as needed.
>
> [Monitoring and Trending] Inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function. The specific type of test performed will be determined before each test. Each test performed for a cable may be a different type of test. Testing of a cable per this program is not required if periodic actions as described under preventive actions are taken and those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Scope would not be met).

The staff found the applicant's response acceptable because the applicant would take preventive actions, when practical, to mitigate any aging effects by limiting the exposure of inaccessible cables to moisture. Testing of a cable per this program is not required if periodic actions are taken and those actions prevent the cable from being exposed to significant moisture.

In the July 9, 2002, letter, the applicant revised the preventive action attribute to the following: "Preventive actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program."

The staff finds this revision acceptable because, as long as the applicant tests the medium-voltage cables that are exposed to significant voltage and standing water for any period of time every 10 years, no preventive actions are necessary.

[Parameters Monitored or Inspected]  Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program are tested to provide an indication of the condition of the conductor insulation.  The specific type of test performed will be determined before each test.  Each test performed for a cable may be a different type of test.

The staff was unable to determine if the test to be performed will be an appropriate test that has been proven to accurately assess the cable condition with regard to water treeing.  In a letter dated October 19, 2002, the staff requested the applicant to modify this attribute to indicate that the test to be performed will be a proven test for detecting deterioration of insulation systems due to wetting.  The staff requested this modification so that it can make a reasonable assurance finding that the test will be capable of detecting insulation degradation and that the effects of aging on inaccessible non-EQ medium-voltage cables will be adequately managed, so that the intended function will be maintained in accordance with the requirement of 10 CFR 54.21(a)(3).

In its response to the staff request, dated November 5, 2002, the applicant provided a revision to the Parameters Monitored or Inspected attribute of the summary description of the Inaccessible Non-EQ Medium-Voltage Cables AMP in the FSAR supplement of each station. The revision is as follows:

> Parameters Monitored or Inspected — Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cable Aging Management Program are tested to provide an indication of the condition of the conductor insulation.  The specific type of test performed will be determined before each test and will be a proven test for providing an indication of the condition of the conductor insulation related to aging effects caused by moisture and voltage stress.  Each test performed for a cable may be a different type of test.

The staff found the applicant's response acceptable because the test to be performed will be a proven test for detecting deterioration of an insulation system due to wetting.

[Detection of Aging Effects]  Medium-voltage cables within the scope of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program are tested at least once every 10 years.  This is an adequate frequency to preclude failures of the conductor insulation.  The staff believes, based on current knowledge, that aging degradation of this cabling would be due to slow-acting mechanisms.  Therefore, the applicant's test schedule is acceptable.

[Monitoring and Trending]  In the previous AMP, the applicant stated that inaccessible non-EQ medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every 10 years per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program to provide an indication of the condition of the conductor insulation and the ability of the cable to perform its intended function.  The specific type of test performed will be determined before each test.  Each test performed for a cable may be a different type of test.  Testing of a cable per this program is not required if periodic actions are taken and if those actions prevent, with reasonable assurance, the cable from being exposed to significant moisture (since the significant moisture criteria defined under Program Scope would not be met).  Since the alternate visual inspection program was proposed to testing, the staff determined that the applicant's monitoring and trending attribute did not provide adequate information about the proposed alternative inspection program to testing in that it did not specify (1) the frequency of inspection, (2) how inspection results will be monitored and trended, (3) if or when operability evaluations for degraded conditions (presence of moisture) would be performed, (4) if or when testing would be performed if moisture is identified, and (5) what corrective actions would be taken in the event that cables exposed to moisture are identified. By letter dated June 26, 2002, the staff identified potential open item B.3.19.2-1 as mentioned above and requested the applicant to provide additional information in response to this potential open item.

In its response dated July 9, 2002, the applicant stated the following:

> The alternative visual inspection program was proposed in the McGuire and Catawba LRA in an attempt to provide a distinction between cables that are exposed to moisture (rain and drain) and those that are exposed to "significant" moisture so that the cables exposed only to "rain and drain" would not require testing.  Trying to quantify this distinction has proven difficult and has raised staff concerns that this distinction, improperly applied, could inadvertently exclude some applicable cables from the program.  Duke acknowledges the staff's concern in this area along with the recognition that some cable installations make it impossible (by currently known means) to verify with reasonable assurance that all portions of some cable runs are not continuously exposed to moisture.  Considering these factors, Duke has now eliminated this distinction regarding moisture exposure by taking a bounding approach.  The aging management program will include any significant voltage exposed in-scope medium-voltage cables that are exposed to standing water (for any period of time).  With the moisture distinction eliminated and all such cables included without further qualification, the need for the proposed alternative inspection program is eliminated.

Since the applicant eliminated the inspection alternative to the 10-year test described in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program, this issue is resolved.

The applicant also revised the Monitoring and Trending attribute, stating that trending actions are not included in the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program.  For McGuire, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for McGuire and by June 12, 2021 (the end of the initial license of McGuire 1).  For Catawba, the first test per the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program will be completed following issuance of renewed operating licenses for Catawba and by December 6, 2024 (the end of the initial license of Catawba 1).  The staff finds that the absence of trending for testing is acceptable since the test is performed every 10 years, and the staff does not see a need for such activities.  The staff also finds the testing schedule acceptable to preclude failures of the conductor insulation since aging degradation is a slow process.

[Acceptance Criteria] The acceptance criteria for each test are defined by the specific type of test performed and the specific cable tested. The staff finds the above acceptance criteria acceptable on the basis that they will follow current industry standards which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the current licensing basis.

[Operating Experience] Operating experience is not relevant for this new program. Industry experience supports both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program.

FSAR Supplement: In response to the staff RAIs, the applicant proposed to revise the Inaccessible Non-EQ Medium Voltage Cables AMP. Pending the staff's receipt of the revised FSAR supplement, this was characterized as confirmatory item 3.6.2-1. In its response to the confirmatory item, dated October 2, 2002, the applicant stated that it will insert the summary description of the revised Inaccessible Non-EQ Medium Voltage Cables AMP (as provided in Duke letters dated July 9, 2002, Attachment 1, pages 89-91, and November 5, 2002) in each station's FSAR supplement in place of the program description previously provided. The staff found the applicant's response to confirmatory item 3.6.2-1 acceptable because the change to the program proposed by the applicant will be reflected in the FSAR supplement.

*3.6.2.3 Conclusions*

On the basis of the staff's evaluation described above, the staff finds that there is reasonable assurance that the effects of aging of inaccessible non-EQ medium-voltage cables will be adequately managed, so that the intended functions will be maintained consistent with the applicant's CLB for the period of extended operation in accordance with the requirement of 10 CFR 54.21(a)(3).

### 3.6.3 Aging Effects Caused by Boric Acid Ingress into Connector Pins

*3.6.3.1 Technical Information in the Application*

In Section 3.6.3 of the LRA, the applicant described the aging effects caused by boric acid ingress into connector pins. The applicant states that potential acid ingress into connector pins was identified as causing aging effects that need to be managed.

3.6.3.1.1 Aging Effects

Table 3.6-1 on page 3.6-1 of the LRA identified corrosion of connector pins as an aging effect caused by exposure to borated water.

#### 3.6.3.1.2 Aging Management Program

The applicant states that it will take credit for an existing program, the Fluid Leak Management Program (which includes boric acid leakage surveillance), for managing aging effects caused by boric acid ingress into non-EQ connector pins at McGuire and Catawba. This AMP is described by the applicant in Section B.3.15 of LRA Appendix B.

### 3.6.3.2 Staff Evaluation

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of connector pins at McGuire and Catawba Nuclear Stations. The staff's evaluation includes a review of the aging effects considered. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on connector pins will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.6.3.2.1 Aging Effects

Aging effects caused by oxidation or corrosion of connector pins because of potential boric acid ingress into connector pins could cause connector failure and interfere with the operation of these circuits. The applicant identified corrosion as an applicable aging effect for the connector pins. The staff concurs with the aging effects identified above by the applicant.

#### 3.6.3.2.2 Aging Management Programs

The staff evaluated the information on aging effects caused by boric acid ingress into connector pins as presented in Section 3.6.3 of the LRA to determine if there is a reasonable assurance that the applicant has demonstrated that the aging effects for low-voltage connectors will be adequately managed, consistent with the applicant's CLB for the period of extended operation.

The applicant credits the Fluid Leak Management Program to manage the aging effects caused by boric acid ingress into non-EQ low-voltage connector pins. Since the Fluid Leak Management Program is credited for managing the aging of several structures and components in different systems, it is considered a common AMP and the staff's evaluation of it is documented in Section 3.0 of the SER. The AMP's effectiveness has been evaluated for electrical components as well. The staff finds that this program is adequate to manage the effect of corrosion of the electrical components.

### *3.6.3.3 Conclusions*

Based on the review of the LRA, the staff concludes that the implementation of the Fluid Leak Management Program will provide a reasonable assurance that the aging effects of oxidation or corrosion of connector pins will be managed. This program will provide reasonable assurance that the intended functions of low-voltage connectors will be maintained consistent with the current licensing basis through the period of extended operation, as required by 10 CFR 54.21(a)(3).

### 3.6.4 Aging Management of Electrical Components Required for Station Blackout (SBO)

In a letter dated January 17, 2002, the staff requested additional information concerning Section 2.5 of the LRA. The staff requested the applicant to clarify why switchyard systems are not relied on in safety analyses or plant evaluations to perform a function in the recovery from an SBO event. In its response dated March 8, 2002, the applicant stated that, based on the results of a recent review of plant documents, McGuire and Catawba components that are part of the power path for offsite power from the switchyard are within the scope of license renewal in accordance with the SBO scoping criterion, 54.4(a)(3). This power path includes portions of the power path from the unit power circuit breakers (PCBs) in the respective switchyard to the safety-related buses in each plant. The power path includes portions of (1) the switchyard systems, (2) the unit main power system, and (3) the nonsegregated-phase bus in the 6.9 kV normal auxiliary power system of each station. In its March 8, 2002, response, the applicant committed to provide the results of the aging management review for the long-lived, passive structures and components associated with the offsite power path by June 30, 2002.

In a letter dated June 26, 2002, the applicant provided the results of its scoping and screening review and AMR review for electrical components and structures associated with the offsite power path. The AMR results were generically applicable for McGuire and Catawba. The staff reviewed the AMR results to determine whether the applicant had demonstrated that the effects of aging for the electrical structures and components in the power recovery path for SBO events will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

*3.6.4.1 AMR Results for Isolated-Phase Bus and Nonsegregated-Phase Bus*

The AMR results for isolated-phase bus and nonsegregated-phase bus are summarized in Attachment 1, Section 5.3, “Aging Management Review Results Table,” of the June 26, 2002, letter from the applicant.

3.6.4.1.1 Aging Effects

The applicant stated that aging management review for McGuire and Catawba isolated-phase bus and nonsegregated-phase bus follows the guidance provided in the EPRI License Renewal Electrical Handbook and is consistent with the guidance provided in NEI 95-10 and the previous review performed for Oconee. Isolated-phase bus and nonsegregated-phase bus descriptions are provided in Chapter 8 of the License Renewal Electrical Handbook.

The applicant stated that McGuire and Catawba isolated-phase bus and nonsegregated-phase bus have three main parts or assemblies: the conductor, the conductor support (insulator), and the bus enclosure. Where nonsegregated-phase bus passes through an outside wall, a wall bushing assembly is used to provide a thermal barrier. As confirmed through a review of manufacturer’s drawings and personnel interviews, McGuire and Catawba isolated-phase bus and nonsegregated-phase bus are similar in design, construction, and materials to the Oconee phase bus described in Section 3.6.2.1 of the Oconee Application with two notable differences. One difference is that the aluminum conductor for the bus section is welded rather than bolted together, and the conductor is bolted only where braided conductors are installed to prevent the propagation of vibration to the rigid conductor. There are fewer bolted connections at McGuire and Catawba than at Oconee. The other difference is that the aluminum bus and braided mating surfaces are silver plated. This raises the potential for formation of silver oxide at the connections for McGuire and Catawba rather than the formation of aluminum oxide, which exists for Oconee. Other differences between the Oconee, McGuire, and Catawba bus are not significant to the AMR.

The applicant stated that, based on industry literature, plant operating experience, and the Oconee application review, the potential aging effects identified in Table 2 of the LRA are required to be included in the phase bus aging management review. This review included industry operating experience reports for phase bus identified in Chapter 11 of the License Renewal Electrical Handbook. This aging effects identification process is consistent with the process used in Section 3.6 of the Oconee application.

<u>Connection Surface Oxidation for Aluminum Conductor Phase Bus</u>. The applicant states that aluminum conductors of the bus section are welded except where braided conductors are used to connect the bus to another component. The aluminum mating surfaces at these connections are coated with copper and then silver plated. The silver plating is highly conductive but does not make a good contact surface since silver exposed to air forms silver oxide on the surfaces. The surfaces are periodically cleaned (to remove any existing silver oxide) and covered with a grease to prevent air from contacting the mating surfaces. The grease precludes oxidation of the silver surface, thereby maintaining good conductivity at the bus connections. The grease is a consumable that is replaced during each routine maintenance of the bus. Therefore, the applicant concludes that applicable aging effects for the aluminum bus connections when exposed to their service conditions for the extended period of operation are adequately addressed through maintenance.

<u>Temperature for Silicone Caulk for Phase Bus</u>. The applicant stated that silicone-rubber-based caulk is used to maintain spacing between the conductor and bushing in a wall bushing assembly. Silicone rubbers have a 60-year service-limiting temperature of 273 °F as documented in Table 9-1 of the License Renewal Electrical Handbook. The isolated-phase bus and nonsegregated-phase bus are installed in the turbine building, service building, and transformer yard, which have a bounding ambient design temperature of 110 °F and negligible radiation. Adding design ohmic heating to the ambient temperature puts the service condition for temperature at 226 °F, which is less than the 60-year service-limiting temperature of 273 °F for silicone rubber. Therefore, silicone rubber has no aging effects due to heat for the extended period of operation that will cause loss of component intended function.

<u>Moisture for Steel Hardware for Phase Bus</u>. The applicant stated that steel hardware (bolts, washers, nuts, etc.) is used on parts of the bus enclosure that are not welded. The enclosure and hardware exposed to external environment (precipitation) were factory coated to inhibit corrosion. Based on collective service experience at Oconee, McGuire, and Catawba (service of from 20 to over 30 years), no signs of corrosion or loss of material have been observed. Therefore, loss of material for steel hardware is not an applicable aging effect that will lead to a loss of intended function for the bus for the period of extended operation.

3.6.4.1.2 Aging Management Programs

The applicant stated that, based on its review of materials and service conditions, no applicable aging effects were identified. Therefore, McGuire and Catawba isolated-phase bus and nonsegregated-phase bus will perform their intended functions in accordance with CLB during the period of extended operation, and no aging management is required.

### *3.6.4.2 Staff Evaluation of AMR Results for Isolated-Phase Bus and Nonsegregated-Phase Bus*

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of electrical components required for SBO at McGuire and Catawba nuclear stations. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on electrical components required for SBO will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.6.4.2.1 Aging Effects

The isolated-phase bus and nonsegregated-phase bus at McGuire and Catawba have three main parts or assemblies: the conductor, the conductor support (insulator), and the bus enclosure. Where nonsegregated-phase bus passes through an outside wall, a wall bushing assembly is used to provide a thermal barrier. The aluminum conductors of the bus sections are welded except where braided conductors are used to connect the bus to another component.

The aging mechanism for the aluminum conductor is connection surface oxidation. The aging effect is change in material properties leading to increased resistance and heating. The aluminum mating surfaces at these connections at McGuire and Catawba are coated with copper and then silver-plated. The silver plating is highly conductive but does not make a good contact surface, since silver exposed to air forms silver oxide on connection surfaces. The applicant stated that the surfaces are periodically cleaned to remove any existing silver oxide and covered with grease to prevent air from contacting the mating surfaces. The grease precludes oxidation of the silver surface, thereby maintaining a good conductivity at the bus connections. Grease is a consumable that is replaced during each routine maintenance of the bus. Therefore, no applicable aging effects are identified for the aluminum bus connections when exposed to the service conditions for the extended period of operation. The staff finds grease precludes oxidation of the connection mating surface, and no aging effects are applicable for aluminum conductor phase bus.

The aging mechanisms for silicone caulk for phase bus are temperature and radiation. The potential aging effect for silicone caulk requiring evaluation is change in material properties leading to loss of maintained spacing between the bus and bushing. Silicone-rubber-based caulk is used to maintain spacing between the conductor and bushing in a wall bushing assembly. The applicant stated that silicone rubbers have a 60-year service-limiting temperature of 273 °F. The isolated phase bus and nonsegregated-phase bus are installed in the turbine building, service building, and transformer yard, which have a bounding ambient design temperature of 110 °F and negligible radiation. Adding design ohmic heating to the ambient temperature puts the service condition for temperature at 226 °F, which is less than the 60-year service-limiting temperature of 273 °F for silicone rubber. Therefore, silicone rubber has no aging effects due to heat for the extended period of operation that will cause loss of component intended function. The staff finds because service conditions for silicone caulk is less than the 60-year service-limiting temperature, no aging effects are applicable to silicone caulk for the extended period of operation.

The aging mechanism for steel (enclosure hardware) is moisture. The potential aging effect is change in material properties (corrosion) leading to loss of function for the part. Steel (bolts, washers, nuts, etc.) is used on parts of the bus enclosure that are not welded. The enclosure and hardware exposed to external environment (precipitation) were factory-coated to inhibit corrosion. The applicant stated that based on collective service experience at Oconee, McGuire, and Catawba, no signs of corrosion or loss of material have been observed. Therefore, loss of material for steel hardware is not an applicable aging effect that will lead to a loss of intended function for the bus for the period of extended operation. The staff finds that enclosure and hardware exposed to external environment were factory coated to inhibit corrosion. Operating experience has also shown that no signs of corrosion or loss of material have been observed. Therefore, corrosion of phase bus enclosure is not an applicable aging effect at McGuire and Catawba.

3.6.4.2.2 Aging Management Programs

The staff concluded that no aging management program is required for isolated-phase bus and nonsegregated-phase bus because no aging effects are identified for isolated-phase bus and nonsegregated-phase bus.

*3.6.4.3 Conclusions*

Based on the review of the LRA, the staff concluded that no aging management program is required for isolated-phase bus and nonsegregated-phase bus. The applicant has demonstrated that there is a reasonable assurance that the McGuire and Catawba isolated-phase bus and nonsegregated-phase bus will perform their intended functions in accordance with the current license basis during the period of extended operation.

*3.6.4.4 Aging Management Review Results for Transmission Conductors, Switchyard Bus, and High-Voltage Insulators*

The AMR results for transmission conductors, switchyard bus, and high-voltage insulators are summarized in Attachment 1, Section 5.3, “Aging Management Review Results Table,” of the June 26, 2002, letter from the applicant. The applicant stated that its AMR of McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators followed the guidance provided in EPRI License Renewal Electrical Handbook and is consistent with the guidance provided in Chapter 8 of the License Renewal Electrical Handbook.

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage isulators are designed and constructed like, and have the same materials as, the Oconee transmission conductors, switchyard bus, and high-voltage insulators with one notable difference. The difference is that multi-cone insulators (where several porcelain cone insulators are cemented together to form a post) used in post application were not included in the Oconee review. Other differences between the Oconee, McGuire, and Catawba transmission conductors, switchyard bus, and high-voltage insulators are not significant to the aging management review.

3.6.4.4.1 Aging Effects

Based on industry literature, plant operating experience, and the applicant's AMR for Oconee, potential aging effects for transmission conductors, switchyard bus, and high-voltage insulators were identified in Section 5.2, "Aging Management Review for Transmission Conductors, Switchyard Bus, and High-Voltage Insulators," of the supplemental information provided in Attachment 1 of the applicant's June 26, 2002, letter. The applicant's review accounted for industry operating experience reports for transmission conductors, switchyard bus, and high-voltage insulators identified in Chapter 11 of the License Renewal Electrical Handbook. The process for identifying aging effects was consistent with the process used in Section 3.6 of the Oconee LRA.

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators are installed in an external environment (bounding 105 °F, negligible radiation, and exposure to precipitation). The aging effects identified for transmission conductors, switchyard bus, and high-voltage insulators are not heat-related; therefore, ohmic heating is not included.

<u>Loss of Conductor Strength for Transmission Conductors</u>. The applicant stated that the transmission conductors included in the AMR are constructed of aluminum conductor steel reinforced (ACSR). The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend to a great extent on air quality, which includes suspended particles chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Duke has been installing and maintaining transmission conductors on its transmission system for more than 50 years and has not yet had to replace any conductors due to aging problems. There are no applicable aging effects that could cause loss of intended function of the transmission conductors for the period of extended operation.

<u>Connection Surface Oxidation for Aluminum Switchyard Bus</u>. The applicant stated that all bus connections within the component boundaries are welded connections. For the ambient environmental conditions at McGuire and Catawba, no aging effects have been identified that could cause a loss of intended function for the extended period of operation. Therefore, there are no applicable aging effects for the aluminum bus.

<u>Surface Contamination Assessment for High-Voltage Insulators</u>. The applicant stated that various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and, in most areas, such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. A large buildup of contamination enables the conductor to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there is a greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. McGuire and Catawba are located in an area with moderate rainfall where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. At McGuire and Catawba, as in most areas of the Duke Power transmission system, contamination build up on insulators is not a problem. Therefore, surface contamination is not an applicable aging effect for the insulators in the service conditions they are exposed to at McGuire and Catawba.

Cracking Assessment for High-Voltage Insulators. The applicant stated that cracks have been known to occur with insulators when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, occurs mainly because of improper manufacturing processes or materials, which make the cement more susceptible to moisture penetration, and the specific design and application of the insulator.

The string insulators susceptible to porcelain cracking caused by cement growth are isolated to bad batches (specific, known brands and manufacture dates) of string insulators used in strain application. The post insulators most susceptible to this aging effect are multi-cone (post) insulators used in cantilever applications. In the mid-1990s when this problem was identified, Duke undertook a program to identify and replace the most susceptible insulators system wide, including those in the McGuire and Catawba switchyards. Accordingly, cracking due to cement growth is not an applicable aging effect for the insulators currently installed in the McGuire and Catawba switchyards.

Loss of Material Due to Wear Assessment for High-Voltage Insulators. The applicant stated that mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing and that when they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspection. Loss of material due to wear will not cause a loss of intended function of the insulators at McGuire and Catawba. Therefore, loss of material due to wear is not an applicable aging effect for insulators.

#### 3.6.4.4.2 Aging Management Programs

The applicant stated that, based upon its review of materials and service conditions, no applicable aging effects were identified. Therefore, McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators will perform their intended functions in accordance with CLB during the period of extended operation, and no aging management is required.

### *3.6.4.5 Staff Evaluation of Aging Management Review Results for Transmission Conductor, Switchyard Bus, and High-Voltage Insulators*

This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of electrical components required for SBO at McGuire and Catawba. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on electrical components required for SBO will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

#### 3.6.4.5.1 Aging Effects

McGuire and Catawba transmission conductors, switchyard bus, and high-voltage insulators are installed in an external environment (bounding 105 °F, negligible radiation, and exposure to precipitation). The aging effects identified for transmission conductors, switchyard bus, and high-voltage insulators are not heat-related so ohmic heating is not included.

The transmission conductors are constructed of ACSR. The most prevalent mechanism contributing to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend to a great extent on air quality, which includes suspended particles chemistry, SO2 concentration in air, precipitation, fog chemistry, and meteorological conditions. Tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor due to corrosion. Corrosion of ACSR conductors is a very slow-acting aging effect, which is even slower in rural areas with generally fewer suspended particles and lower SO2 concentrations in the air than in urban areas. The applicant stated that it has been installing and maintaining transmission conductors on its transmission system for more than 50 years and has not yet had to replace any conductors due to aging problems. The staff finds that based on the test results, corrosion of ACSR conductors is a very slow-acting aging effect. Operating experience has also shown that corrosion of ACSR conductors is not a problem for transmission conductors at Duke's plants. Therefore, loss of material strength of ACSR transmission conductors does not require aging management for the period of extended operation.

All bus connections within the component boundaries are welded connections. For the ambient environment conditions at McGuire and Catawba, no aging effects have been identified that could cause a loss of intended function for the extended period of operation. Therefore, the staff concludes that there are no applicable aging effects for the switchyard bus.

Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual, and in most areas such contamination is washed away by rain. The glazed insulator surface aids this contamination removal. A large buildup of contamination enables the conductor to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there is a greater concentration of airborne particles such as near facilities that discharge soot or near the sea coast where salt spray is prevalent. McGuire and Catawba are located in an area with moderate rainfall where airborne particle concentrations are comparatively low. Consequently, the rate of contamination buildup on the insulators is not significant. At McGuire and Catawba, as in most areas of the Duke Power transmission system, contamination buildup on insulators is not a problem. The staff finds that contamination buildup on the high-voltage insulators is not significant. Therefore, surface contamination is not an applicable aging effect for the insulators in the service conditions they are exposed to at McGuire and Catawba.

Cracks have been known to occur with insulators when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, occurs mainly because of improper manufacturing process or materials, which make the cement more susceptible to moisture penetration, and the specific design and application of the insulator. The applicant stated that the string insulators susceptible to porcelain cracking caused by cement growth are isolated to bad batches (specific, known brands and manufacture dates) of string insulators used in strain application. The post insulators most susceptible to this aging effect are multi-cone (post) insulators used in cantilever applications. In the mid-1990s when this problem was identified, Duke undertook a program to identify and replace the most susceptible insulators system wide, including those in the McGuire and Catawba switchyards. The staff finds that porcelain cracking caused by cement growth is mainly due to improper manufacturing process or material. Accordingly, cracking due to cement growth is not an applicable aging effect for the insulators currently installed in the McGuire and Catawba switchyards.

Mechanical wear is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of the insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware. Although this mechanism is possible, experience has shown that the transmission conductors do not normally swing and that when they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Wear has not been identified during routine inspection. Loss of material due to wear will not cause a loss of intended function of the insulators at McGuire and Catawba. The staff finds that loss of material due to mechanical wear is not an applicable aging effect because transmission conductors do not normally swing, and if they do, because of substantial wind, they do not continue to swing for very long once the wind has subsided. Therefore, loss of material due to wear is not an applicable aging effect for insulators.

3.6.4.5.2 Aging Management Programs

The staff concluded that since no aging effects are identified for transmission conductors, switchyard bus, and high-voltage insulators, no aging management program is required.

*3.6.4.6 Conclusions*

Based on the review of the information provided in a letter from the applicant dated June 26, 2002, the staff concludes that no AMP is required for transmission conductors, switchyard bus, and high-voltage insulators. The applicant has demonstrated that there is a reasonable assurance that transmission conductors, switchyard bus, and high-voltage insulators at McGuire and Catawba will continue to perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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# 4. TIME-LIMITED AGING ANALYSES

## 4.1 Identification of Time-Limited Aging Analyses

The applicant described its identification of time-limited aging analyses (TLAAs) in Section 4.0 of the McGuire and Catawba LRA. The staff reviewed this section of the LRA to determine if the applicant had identified the TLAAs and demonstrated that they meet one of the criteria required by 10 CFR 54.21(c)(1). The staff also reviewed the LRA to determine if plant-specific exemptions had been identified by the applicant.

### 4.1.1 Technical Information in the Application

In Section 4.1 of the LRA, the applicant described the requirements for the technical information to be reported in the LRA regarding TLAAs, as stated in 10 CFR 54.21(c). These include a list of TLAAs, as defined in 10 CFR 54.3, "Definitions," and, if applicable, a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 that are based on TLAAs. The applicant also described the following criteria used to identify TLAAs at both McGuire and Catawba as required by 10 CFR 54.3:

- involve systems, structures, and components within the scope of license renewal as delineated in 10 CFR 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- were determined to be relevant by the applicant in making a safety determination
- involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b)
- are contained or incorporated by reference in the CLB

The applicant listed the following specific documents that were reviewed to identify potential TLAAs for both plants:

- Duke/NRC licensing correspondence
- NUREG-0422, as supplemented, SER for McGuire
- NUREG-0954, as supplemented, SER for Catawba
- UFSARs for both McGuire and Catawba
- ITS for both McGuire and Catawba
- Facility Operating Licenses for both McGuire and Catawba

The document set used for the search is contained in the Electronic Licensing Library (ELL). The ELL contains over 30,000 documents and consists of virtually all correspondence between Duke Energy (formerly Duke Power Company) and the NRC (and its predecessor the Atomic Energy Commission). The information developed from the review of plant-specific source documents was reviewed to determine which calculations and analyses meet all six criteria of 10 CFR 54.3. The analyses and calculations that meet all six criteria were identified as either McGuire-specific or Catawba-specific TLAAs.

As required by 10 CFR 54.21(c)(1), an evaluation of each TLAAs must be performed to demonstrate one of the following:

(1) the analyses remain valid for the period of extended operation
(2) the analyses have been projected to the end of the period of extended operation
(3) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation

In Sections 4.2 through 4.7 of the LRA, the applicant provided TLAAs for the following:

- reactor vessel neutron embrittlement, including analyses for upper shelf energy, pressurized thermal shock, and pressure-temperature limits
- metal fatigue, including analyses of ASME Section III Class 1 component fatigue, fatigue evironmental effects, and ASME Section III Class 2 and 3 piping fatigue
- environmental qualification of electrical equipment
- containment liner plate, metal containments, and penetration fatigue analysis
- reactor coolant pump flywheel fatigue
- leak-before-break analysis
- depletion of nuclear service water pond volume due to runoff

### 4.1.2 Staff Evaluation

Pursuant to 10 CFR 54.21(c), an applicant for license renewal is required to provide a list of TLAAs as part of the application for the renewal of a license. The staff reviewed the TLAAs identified by the applicant and described in Sections 4.2 through 4.7 of the LRA to verify that they met the six criteria of 10 CFR 54.3. The staff also sought to determine if the applicant had demonstrated that the analyses remain valid for the period of extended operation, the analyses had been projected to the end of the period of extended operation, or the effects of aging on the intended functions will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1).

### 4.1.3 Conclusions

The staff reviewed the information provided in LRA Section 4.1 and concludes that the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c), and that no 10 CFR 50.12 exemptions have been granted on the basis of the TLAAs as defined in 10 CFR 54.3.

## 4.2 Reactor Vessel Neutron Embrittlement

The application includes three TLAAs for evaluation of the reactor vessel (RV) beltline materials, including (1) calculation of the end-of-extended-life Charpy upper shelf energy value ($C_vUSE$ values) for each beltline material, (2) calculation of the end-of-extended-life reference temperature value (i.e., $RT_{PTS}$ values) for each beltline material, and (3) a calculation of pressure-temperature (P-T) limits. Each analysis has been updated to consider 20 years of additional plant operation at power. The TLAAs take into account the effects of the additional extended-operating-period neutron irradiation on the previous calculated end-of-life $C_vUSE$, the

$RT_{PTS}$, and P-T limit values for the McGuire and Catawba reactor vessels, and conservatively base the evaluations through 54 EFPYs of power operation.

### 4.2.1 Upper Shelf Energy

Appendix G to 10 CFR Part 50 requires that reactor vessel beltline materials have $C_v$USE values in the transverse direction for the base metal and along the weld for the weld material, according to the ASME Code, of no less than 75 ft-lb (102 J) initially, and must maintain $C_v$USE values throughout the life of the vessel of no less than 50 ft-lb (68 J). However, $C_v$USE values below these criteria may be acceptable if it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that the lower values of $C_v$USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of $C_v$USE values and describes two methods for determining $C_v$USE values for reactor vessel beltline materials, depending on whether a given reactor vessel beltline material is represented in the plant's reactor vessel material surveillance program (i.e., 10 CFR Part 50, Appendix H program).

*4.2.1.1 Technical Information in the Application*

Section 4.2.1 of the application addressed the requirement that RV beltline materials have a pre-irradiated $C_v$USE of not less than 75 ft-lb (102 J) and maintain a $C_v$USE of not less than 50 ft-lb (68 J) throughout the life of the vessel, unless it is demonstrated, in a manner approved by the Director of the Office of Nuclear Reactor Regulation, that lower values of $C_v$USE will provide margins of safety against fracture that are equivalent to those required by Appendix G of Section XI of the ASME Code. The applicant stated that the $C_v$USE value has been calculated through the period of extended operation using guidance from Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Pressure Vessel Materials." A value of 54 EFPYs was used as the end-of-life criterion for the RV. The application contains the information derived from the $C_v$USE analysis. It includes a list of all beltline materials, the weight percent copper in the steel, the end-of-life fluence for the reactor vessel located one-quarter from the vessel's inside surface (i.e., 1/4T thickness of the vessel), and the initial and final $C_v$USE values. The applicant concludes that the end-of-life $C_v$USE results are above the screening criterion of 50 ft-lb (68 J). The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

*4.2.1.2 Staff Evaluation*

The applicant summarized the end-of-extended operating period upper shelf energy analyses for the McGuire and Catawba reactor vessel beltline materials in Tables 4.2-1 through 4.2-4 of the LRA. Since all of the $C_v$USE values are above the 50 ft-lb (68 J) screening criterion, the staff finds that, with respect to $C_v$USE, the Duke RVs have sufficient margin to perform their intended function through the end of the period of extended operation.

By letter dated January 28, 2002, the staff requested, in RAI 4.2-1, the applicant to clarify that Tables 4.2-1 through 4.2-4 of the LRA include the results of the TLAAs for upper shelf energies of beltline nozzle plates/forging materials and nozzle weld materials in the McGuire and Catawba vessels.

In its response dated April 15, 2002, the applicant stated that TLAAs for upper shelf energy (USE) of the reactor vessel beltline shell and nozzle materials are addressed in Section 4.2.1 and Tables 4.2-1 through 4.2-4 of the LRA. During its review, the applicant projected that some of the nozzle region locations would have an estimated 54 EFPYs fluence greater than $10^{17}$ neutrons/$cm^2$. Therefore, in accordance with 10 CFR 50, Appendix H, the applicant performed an analysis of nozzle region locations and confirmed that they are not the most limiting materials with regard to radiation damage. This analysis is based on a review of the certified material test reports which determined bounding material values for the nozzle region materials. This analysis provides the basis for the responses to this RAI and is available for onsite inspection. All nozzle region materials have been evaluated and a bounding value of USE was calculated. Since none of these nozzle region locations are limiting, no changes to the reactor vessel capsule surveillance program are necessary for license renewal.

In its April 15, 2002, response to RAI 4.2-1, the applicant provided the requested information and noted that, during the preparation of the responses to this RAI, Duke identified errors in $C_v$USE values for the bounding nozzle materials, as summarized in Tables 4.2-1 through 4.2-4 of the LRA. Therefore, the applicant performed revised $C_v$USE value calculations for the bounding nozzle base-metal and weld materials and submitted the revised calculations in Table 4.2-1A, which was included in the applicant's response to RAI 4.2-1. Table 4.2-1A provides the updated $C_v$USE values for the bounding nozzle region locations and supercedes the $C_v$USE values for the nozzle region materials previously provided in Section 4.2.1 of the LRA. The applicant also provided the requested additional unirradiated $C_v$USE values and alloying chemistry in Table 4.2-1C in its April 15, 2002, response to RAI 4.2-1.

The staff performed an independent calculation of the end-of-extended life $C_v$USE values for the beltline shell and nozzle materials used to fabricate the McGuire and Catawba RVs. The staff confirmed that none of the beltline nozzle materials were represented in the applicant's reactor vessel material surveillance program (i.e., 10 CFR Part 50 Appendix H Program; refer to AMP B.3.26 for a description of this program). For those RV beltline materials that were not represented in the applicant's reactor vessel material surveillance program, the staff applied Regulatory Position 1.2 of Regulatory Guide 1.99, Revision 2, to estimate the percent loss of $C_v$USE as a function of copper content and neutron fluence for the beltline materials, as evaluated using the 54 EFPYs end-of-extended life fluence. For RV materials represented in the applicant's reactor vessel material surveillance program, the staff applied Regulatory Position 2.2 as its basis for estimating the percentage drop in $C_v$USE. The staff confirmed that all RV beltline shell and nozzle materials will continue to satisfy the $C_v$USE value requirements of 10 CFR Part 50, Appendix G, through the end-of-extended operating lives for the McGuire and Catawba reactors units. Therefore, the staff concludes that the applicant's TLAA for calculating the USE values of the McGuire and Catawba RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have adequate upper shelf energy levels and fracture toughness through the end-of-extended operating periods for the McGuire and Catawba reactor units.

By letter dated September 13, 2002, the staff requested additional information regarding the impact of the fracture toughness data from a Diablo Canyon 2 surveillance capsule (capsule V) on the USE assessments for the longitudinal RV beltline welds fabricated from heat No. 21935/12002 at the end of the extended operating term (or end of life extended, EOLE). For tracking purposes, this request was characterized by the staff as open item 4.2-1. The material is common to both the McGuire 1 and Diablo Canyon 2 RVs. For McGuire 1, the welds fabricated from this heat are the lower shell longitudinal welds under the plant-specific designation 3-442. This is the limiting McGuire 1 RV material for USE. In its response letter dated October 28, 2002, the applicant provided the following response to item 4.2-1, as it relates to the USE TLAA for McGuire 1 RV longitudinal welds fabricated from the weld heat No. 21925/12008, using all applicable surveillance data for the heat from the Diablo Canyon 2 RV material surveillance program (inclusive of fracture toughness tests performed on test specimens from Diablo Canyon 2 capsules U, X, Y, and V):

> To evaluate the impact of new data to the USE reported in Table 4.2-1 of the Application, Duke applied the chemistry data from the surveillance capsule report, WCAP-15423, concerning the same weld wires Heat 12008 and 21935 and Linde 1092 Flux Lot as McGuire Unit 1 Lower Shell Longitudinal Weld Seams 3-442A, B, C. The percent copper changed from 0.213 percent (as reported in the Application) to 0.219 percent (as reported in WCAP-15423). Using Figure 2 of RG 1.99, Rev. 2, the difference in USE is less than a 0.5 percent drop. Therefore, the EOL USE would conservatively be 1 ft-lb less than the values provided in Table 4.2-1 of the Application and still above the regulatory limit of 50 ft-lb.

To independently assess the applicant's response to open item 4.2-1 and revised USE evaluation for the McGuire 1 RV welds fabricated from heat No. 21935/12008, the staff incorporated the Diablo Canyon 2 capsule V data for the weld heat into the staff's "Reactor Vessel Integrity Database (RVID)." The staff recalculated the USE value for the lower shell longitudinal 3-442 welds using the limiting fluence for these welds at EOLE, as assessed for the 1/4T location of the RV (i.e., $1.63 \times 10^{19}$ n/cm$^2$), and using all relevant Diablo Canyon 2 surveillance data for heat No. 21935/12008 (i.e., inclusive of the capsule V data). Based on these inputs, the staff recalculated the USE value for these welds to be 57 ft-lb at EOLE. The staff's revised USE value for these welds at EOLE is above 50 ft-lb screening criterion of the rule for ferritic materials in the irradiated condition and demonstrates that the McGuire 1 RV will comply with the USE screening criteria of 10 CFR Part 50, Appendix G, Section IV.A.1, through the expiration of the extended period of operation for McGuire 1. The staff therefore concludes that the applicant's TLAA for the USE evaluation of McGuire 1 is acceptable pursuant to 10 CFR 54.21(c)(1)(ii). This resolves open item 4.2-1 as it relates to the USE assessment for McGuire 1.

### 4.2.2 Pressurized Thermal Shock

Section 50.61 of 10 CFR provides the fracture toughness requirements protecting the reactor vessels of pressurized water reactors against the consequences of pressurized thermal shock (PTS). Licensees are required to perform an assessment of the reactor vessel materials' projected values of the PTS reference temperature, $RT_{PTS}$, through the end of their operating license. If approved for license renewal, this would include TLAAs for PTS up through the end-of-extended operating terms for the McGuire and Catawba units. Upon approval of its application for an extended period of operation for Catawba and McGuire, this period would be 54 EFPYs. The rule requires each licensee to calculate the end-of-life nil ductility temperature value (i.e., $RT_{PTS}$ value) for each material located within the beltline of the reactor pressure vessel. The $RT_{PTS}$ value for each beltline material is the sum of the unirradiated nil ductility reference temperature ($RT_{NDT}$) value, a shift in the $RT_{NDT}$ value caused by exposure to high energy neutron irradiation of the material (i.e., $\Delta RT_{NDT}$ value), and an additional margin value to account for uncertainties (i.e., M value). 10 CFR 50.61 also provides screening criteria against which the calculated $RT_{PTS}$ values are to be evaluated. For reactor vessel beltline base-metal materials (forging or plate materials) and longitudinal (axial) weld materials, the materials are considered to provide adequate protection against PTS events if the calculated $RT_{PTS}$ values are less than or equal to 270 °F; for reactor vessel beltline circumferential weld materials, the materials are considered to provide adequate protection against PTS events if the calculated $RT_{PTS}$ values are less than or equal to 300 °F. Regulatory Guide 1.99, Rev. 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of $RT_{PTS}$ values and describes two methods for determining $RT_{PTS}$ for reactor vessel materials, depending on whether a given reactor vessel beltline material is represented in the plants reactor vessel material surveillance program (i.e., 10 CFR Part 50, Appendix H program).

*4.2.2.1 Technical Information in the Application*

Section 4.2.2 of the LRA addresses the 10 CFR 50.61 requirement that the RV be protected against pressurized thermal shock. The applicant states that the screening criteria in 10 CFR 50.61 are 270 °F for plates, forgings, and axial welds, and 300 °F for circumferential welds. According to the regulation, if the calculated $RT_{PTS}$ values for the beltline materials are less than the screening criteria, then the RV is acceptable with respect to risk of failure during postulated thermal shock transients. In this part of the application, the applicant describes the projected values of $RT_{PTS}$ over the period of extended operation (54 EFPY) to demonstrate that the screening criteria are not violated. The applicant states that this analysis has been carried out and that the results do not exceed the screening criteria. The applicant states that the calculations have been projected through the period of extended operation and shown to meet the requirements of 10 CFR 54.21(c)(1)(ii).

*4.2.2.2 Staff Evaluation*

The applicant provided its end-of-extended operating PTS assessments for the McGuire and Catawba beltline reactor vessel shell materials in Tables 4.2-5 through 4.2-8 of the LRA, but did not include the PTS assessments of the beltline nozzle and weld materials. By letter dated January 28, 2002, the staff requested, in RAI 4.2-1, the following information regarding the end-of-extended operating period PTS assessments for the McGuire and Catawba beltline reactor vessel shell and nozzle materials:

(1) The corresponding pressurized thermal shock time-limited aging analysis (TLAA) assessments for the nozzle plate/forging materials and nozzle weld materials that were analyzed for upper shelf energy adequacy (as provided for in Tables 4.2-1 through 4.2-4 of the LRA)

(2) The unirradiated Charpy impact data, unirradiated initial $RT_{NDT}$ data (i.e., $RT_{NDT(U)}$ data) and alloying chemistry data (especially copper and nickel contents, as well as phosphorous and sulfur contents) for the beltline nozzle plates/forging materials and nozzle weld materials in the McGuire and Catawba vessels on the respective dockets for the McGuire and Catawba reactor units (i.e., Dockets Nos. 50-369, 50-370, 50-413 and 50-414), and the bases for the data being docketed

In its response to RAI 4.2-1, dated April 15, 2002, the applicant provided the following additional information and data regarding end-of-extended operating period PTS assessments for the McGuire and Catawba beltline reactor vessel shell and nozzle materials:

- Table 4.2-1B, providing revised PTS assessments for the bounding beltline nozzle base metal and weld materials for the McGuire and Catawba reactor vessels
- Table 4.2-1C, providing selected unirradiated upper shelf energy, unirradiated $RT_{NDT}$, and alloying chemistry data for the bounding beltline nozzle base metal and weld materials for the McGuire and Catawba reactor vessels

The staff performed an independent calculation of the $RT_{PTS}$ values for the McGuire and Catawba beltline reactor vessel shell and nozzle materials, as assessed, based on the projected end-of-extended operating term (54 EFPY) neutron fluences for the materials. In reviewing the applicant's description of the PTS analysis, the staff examined the data and results of the analysis, as summarized in Tables 4.2-5 through 4.2-8 of the LRA and in Tables 4.2-1B and 4.2-1C of the applicant's response to RAI 4.2-1. Although the staff's calculated $RT_{PTS}$ values for the RV beltline shell and nozzle materials were not always consistent with the applicant's calculated $RT_{PTS}$ values, both the staff's and the applicant's PTS analyses confirm that the $RT_{PTS}$ values for the McGuire and Catawba beltline materials will remain under the PTS screening criteria of 10 CFR 50.61 through the end-of-the-extended-operating periods for the units. For the McGuire 1 RV, the staff determined that the lower shell plate longitudinal welds 3-442 A and C are the most limiting materials and calculated the end-of-extended operating term $RT_{PTS}$ value for these materials to be 248 °F. For the McGuire 2 RV, the staff determined that lower shell forging 04 is the most limiting material and calculated the end-of-extended operating term $RT_{PTS}$ value for this material to be 152 °F. For the Catawba 1 RV, the staff determined that lower shell forging 04 is the most limiting material and calculated the end-of-extended operating term $RT_{PTS}$ value for this material to be 62 °F. For the Catawba 2 RV, the staff determined that intermediate shell plate B8605-2 is the most limiting material and calculated the end-of-extended operating term neutron fluence for this material to be 133 °F. All of these materials meet the 10 CFR 50.61 screening criteria for longitudinal weld and base metal materials of 270 °F. Based on these considerations, the staff finds the applicant's TLAAs for protecting the McGuire and Catawba vessels against PTS to be acceptable because the staff confirmed that the $RT_{PTS}$ values for all McGuire and Catawba reactor vessel beltline shell and nozzle materials remain below the screening criteria of 10 CFR 50.61. The staff therefore concludes that the applicant's TLAA for calculating the $RT_{PTS}$ values for the McGuire and Catawba RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have sufficient protection against PTS events through the end-of-extended operating periods for the McGuire and Catawba reactor units.

By letter dated September 13, 2002, the staff requested additional information regarding the impact of the fracture toughness data from the Diablo Canyon 2 surveillance capsule on the PTS assessments for the longitudinal RV beltline welds fabricated from heat No. 21935/12002 at the end of the extended operating term (or end of life extended or EOLE). For tracking purposes, this request was characterized by the staff as open item 4.2-1. The material is common to both the McGuire 1 and Diablo Canyon 2 RVs. For McGuire 1, the welds fabricated from this heat are the lower shell longitudinal welds under the plant-specific designation 3-442. This is the limiting McGuire 1 RV material for PTS.

In its response to open item 4.2-1, dated October 28, 2002, the applicant provided a revised PTS evaluation for these welds. Using a limiting fluence of $2.73 \times 10^{19}$ n/cm$^2$ at EOLE, the applicant's revised PTS assessment projected the $RT_{PTS}$ values for these welds to be 253 °F using all relevant surveillance capsule data for the heat No. 21935/12008, as obtained from docketed information from the Diablo Canyon 2 RV material surveillance program (inclusive of fracture toughness tests performed on test specimens from Diablo 2 capsules U, X, Y, and V). This $RT_{PTS}$ value at EOLE meets the screening criterion for longitudinal welds as stated in the PTS rule (i.e., the value is less than 270 °F) and is, therefore, acceptable.

To independently assess the applicant's response to open item 4.2-1 and revised PTS evaluation for the McGuire 1 RV welds fabricated from heat No. 21935/12008, the staff incorporated the Diablo Canyon 2 capsule V data for the weld heat into the staff's "Reactor Vessel Integrity Database (RVID)." The staff recalculated the $RT_{PTS}$ value for the lower shell longitudinal 3-442 welds using the limiting fluence for these welds at EOLE (i.e., $2.73 \times 10^{19}$ n/cm$^2$) at the inner surface of the RV, and using all relevant Diablo Canyon 2 surveillance data for heat No. 21935/12008 (i.e., inclusive of the Capsule V data). The staff recalculated the $RT_{PTS}$ value for these welds to be 260 °F at EOLE. The staff's revised $RT_{PTS}$ value for these welds at EOLE meets the screening criterion for longitudinal welds as stated in the PTS rule and demonstrates that the McGuire 1 RV will comply with the fracture toughness and PTS criteria of 10 CFR 50.61 through the end of the extended period of operation for McGuire 1. The staff therefore concludes that the applicant's TLAA for the PTS evaluation of McGuire 1 is acceptable pursuant to 10 CFR 54.21(c)(1)(ii). This resolves open item 4.2-1 as it relates to the PTS assessment for McGuire 1.

### 4.2.3 P-T Limits

The requirements in 10 CFR Part 50, Appendix G, are designed to protect the integrity of the reactor coolant pressure boundary in nuclear power plants. The staff evaluates the pressure-temperature (P-T) limit curves based on NRC regulations and guidance. Appendix G to 10 CFR Part 50 requires that P-T limit curves be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code. Appendix G to
10 CFR Part 50 also provides minimum temperature requirements that must be considered in the development of the P-T limit curves. SRP Section 5.3.2 provides an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code. The critical locations in the RPV beltline region for calculating heatup and cooldown P-T curves are the 1/4 thickness (1/4T) and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.

Operation of the RCS is also limited by the net positive suction curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, in order to heat up and cool down, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G P-T limits and the net positive suction curves of the reactor coolant pumps.

*4.2.3.1 Technical Information in the Application*

In Section 4.2.3 of the LRA, the applicant addresses the requirement in 10 CFR Part 50, Appendix G, that normal operations, including heatup, cooldown, and transient operating conditions, and pressure-test operations of the RV be accomplished within established P-T limits. These limits are established by calculations that utilize the materials and fluence data obtained through the unit specific reactor surveillance capsule program.

*4.2.3.2 Staff Evaluation*

The P-T limits are established by calculations that utilize the materials and fluence data obtained through the unit-specific reactor surveillance capsule program.

Normally, the P-T limits are calculated for several years into the future and remain valid for an established period of time not to exceed the current operating license expiration. The current P-T limit curves for the McGuire units are acceptable through 16 EFPYs of power operation; the current P-T limit curves for the Catawba units are acceptable though 15 EFPYs of power operation. Section 50.90 of 10 CFR requires licensees to submit new P-T limit curves for operating reactors for review and have the curves approved and implemented into the Technical Specifications for the reactor units prior to the expiration of the most current P-T limit curves approved in the Technical Specifications. The applicant will be required to submit the extended-period-of-operation P-T limit curves for the McGuire and Catawba RVs and have the curves approved against the criteria of 10 CFR Part 50, Appendix G, and implemented into the Technical Specifications prior to operation of the reactors during the extended operating terms for the units.

The issue raised in open item 4.2-1 on the McGuire 1 TLAAs for neutron irradiation embrittlement (i.e., the McGuire 1 TLAAs for PTS, USE, and P-T limits), as stated in the staff's letter of September 9, 2002, does not change the staff's conclusion that the applicant is required to submit P-T limit curves for the period of extended operation before it begins operation beyond the first 40 years. However, since the P-T limits for McGuire 1 are based on the $RT_{NDT}$ value for the RV lower shell longitudinal welds fabricated from material heat No. 21935/12008, any P-T curves for McGuire 1 for the extended period of operation, when submitted to the staff for review and approval, will need to account for all relevant surveillance capsule data for this heat as obtained from the Diablo Canyon 2 RV material surveillance program. The staff will evaluate the extended-period-of-operation P-T limit curves for the McGuire and Catawba RVs prior to expiration of the 40-year, current-operating-term P-T limit curves for the units. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operations of the RCS for the McGuire and Catawba units will be done in a manner that ensures the integrity of the RCS during the extended periods of operation for the McGuire and Catawba units as required by 10 CFR 54.21(c)(1)(ii).

### 4.2.4 FSAR Supplement

On the basis of the staff's evaluation described above, the summary description for the RCS TLAAs described in the FSAR Supplement (LRA, Appendix A) are acceptable.

### 4.2.5 Conclusions

The staff has reviewed the TLAAs regarding the maintenance of acceptable Charpy USE levels for the McGuire and Catawba RV materials and the ability of the McGuire and Catawba reactor vessels to resist failure during postulated PTS events. On the basis of this evaluation, the staff concludes that the applicant's TLAAs for Charpy USE and PTS meet the respective requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.61 for the McGuire and Catawba

RV beltline materials as evaluated to the end-of-extended-operating periods for the McGuire and Catawba units, and therefore satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for 60 years of operation. The staff will evaluate the end-of-extended-operating term P-T limit curves for the McGuire and Catawba reactor units upon submittal by the applicant. The staff's review of the extended-period-of-operation P-T limit curves, when submitted, will ensure that the operations of the RCS for the McGuire and Catawba units will be done in a manner that ensures the integrity of the RCS during the extended periods of operation for the McGuire and Catawba units and that the curves, when submitted, will satisfy the requirements of 10 CFR 54.21(c)(1)(ii) for the period of extended operation.

## 4.3 Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity due to metal fatigue, initiating and propagating cracks in the material. The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for plant mechanical components in the McGuire and Catawba facilities and, consequently, fatigue is part of the current licensing basis for these components. The applicant addressed the TLAA evaluations performed to address thermal fatigue analyses of plant mechanical components in Section 4.3 of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has evaluated the TLAA in accordance with the requirements of 10 CFR 54.21(c)(1).

### 4.3.1 Technical Information in the Application

The applicant discussed the evaluation of ASME Section III, Class 1 components in Section 4.3.1 of the LRA. The applicant indicated that the Thermal Fatigue Management Program (TFMP) will be used to manage thermal fatigue of these components during the period of extended operation for both McGuire and Catawba. The elements of the TFMP are described in Section 4.3.1.1 of the LRA. The applicant indicated that the scope of the program includes the following components:

- RCS Class 1 components (including piping connected to the RCS falling under the purview of NRC Bulletins 88-08 and 88-11)
- the replacement steam generators (RSG) Class 1 portion and selected non-Class 1 portions of the RSG
- components falling within the ISI Program that contain flaws that exceed acceptance standards, but were shown to be acceptable using fracture analyses techniques that used an assumed set of thermal transient cycles
- four Catawba non-Class 1 heat exchangers designed based on RCS thermal cycle transient limits

The applicant described the actions taken to address the issue of environmentally assisted fatigue in Section 4.3.1.2 of the LRA for both McGuire and Catawba. The applicant indicated that it will use Method 2 contained in draft EPRI report, “Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47),” to perform the evaluation. The applicant also indicated that the evaluation will address the fatigue sensitive component locations identified in NUREG/CR-6260, “Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components.”

The applicant described the evaluation of ASME Section III, Class 2 and 3 piping in Section 4.3.2 of the LRA for both McGuire and Catawba. The applicant also indicated that a number of systems designed to the requirements of ANSI B31.1 are in the scope of license renewal. The applicant concluded that the Class 2 and 3 piping analyses of these systems remain valid for 60 years of operation.

**4.3.2 Staff Evaluation**

Components of the RCS at both McGuire and Catawba were designed to the Class 1 requirements of the ASME Code. The Class 1 requirements contain explicit criteria for the fatigue analysis of components. Consequently, the applicant identified the fatigue analysis of these components as TLAAs. The staff reviewed the applicant's evaluation of the ASME Class 1 RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion requires that the CUF not exceed 1.0.

The applicant relies on the TFMP to manage the thermal fatigue design basis of Class 1 components during the period of extended operation. Tables 5-2 and 5-49 of the McGuire UFSAR and Table 3-50 of the Catawba UFSAR contain a list of transient design conditions and associated design cycles used for the design of Class 1 components. By letter dated January 28, 2002, the staff requested, in RAI 4.3-1, that the applicant provide the following data:

- the current number of operating cycles and a description of the method used to determine the number and severity of the design transients from the plant operating history
- the number of operating cycles estimated for 60 years of plant operation and a description of the method used to estimate the number of cycles at 60 years

In its response dated April 15, 2002, the applicant indicated that plant operating conditions are continually monitored for plant conditions that meet the definition of a transient monitored by the TFMP. The applicant further indicated that the parameters associated with the number and severity of these transients is entered into a database. The applicant provided the current number of cycles for each transient at each unit in Table 4.3-1 of its response. The applicant's response indicated that the projected number of transients would not exceed the number assumed in the design for a 60-year operating period. The applicant also identified new transients associated with the McGuire replacement steam generators that will be added to the TFMP. These new transients are also identified in Table 4.3-1 of its response.

Although the projections are for a 60-year operating period, thermal fatigue of Class 1 piping and components is monitored by the TFMP and not an analytical demonstration pursuant to 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii). Therefore, the staff's evaluation of the applicant's TLAA for monitoring thermal fatigue of Class 1 piping and components is for the period of extended operation, not a 60-year operating period.

The applicant also identified the design transients listed in Tables 5-2 and 5-49 of the of the McGuire UFSAR and Table 3-50 of the Catawba UFSAR that are not tracked by the TFMP.

The applicant indicated that the estimated design cycles associated with loading and unloading at 5 percent of full power were based on the assumption of load-follow operation, whereas the plant is operated in the base-load mode. The staff agrees that the number of design cycles listed in the UFSAR tables for these transients are conservative, based on the information presented in NUREG/CR-6260 for Westinghouse plants. The applicant also indicated that the step load increase and decrease of 10 percent of full power causes insignificant fatigue and is not counted. This transient was not identified as a major contributor to fatigue usage for Westinghouse plants in NUREG/CR-6260. The staff notes that, although this transient is monitored at the Turkey Point, Surry, and North Anna facilities, the responses to staff RAIs regarding the LRAs for these facilities indicates that the number of these design transients is expected to be far less than design number for the period of extended operation. On the basis of monitoring at other facilities and the information presented in NUREG/CR-6260, the staff finds the applicant's statement, that this transient causes insignificant fatigue, a reasonable justification for why the step load increase and decrease of 10 percent of full power is not counted in the TFMP.

The Catawba UFSAR lists a large number of design cycles for charging and letdown flow changes. The applicant's response indicates that these transients cause insignificant fatigue and are not counted. NUREG/CR-6260 contains a discussion of these transients for the newer vintage Westinghouse plant. The discussion indicates that these transients are not normally counted at PWRs, although some PWRs have reported that the actual cycles of these transients are less than the numbers assumed in the design calculations. However, the NUREG/CR-6260 evaluation indicates the fatigue usage at the charging nozzle for these transients is significant when the reactor water environment is considered. The charging nozzle is one of the locations that the applicant will assess for fatigue environmental effects. The assessment for fatigue environmental effects is discussed later in this section of this SER.

The Westinghouse Owners Group (WOG) issued Topical Report WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," to address aging management of the RCS piping. Renewal applicant action item 8 of the accompanying staff SE requests that a license renewal applicant perform an additional fatigue evaluation or propose an AMP to address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575. By letter dated January 28, 2002, the staff requested, in RAI 4.3-3, that the applicant discuss how the TFMP addresses the components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP1475-A. In its response dated April 15, 2002, the applicant indicated that WCAP-14575-A had not been considered in the LRA. However, the applicant indicated that it had reviewed WCAP-14575-A in order to respond to the RAI. The applicant indicated that the TFMP manages the thermal fatigue design basis for the components identified in WCAP-14575-A. The applicant's TFMP requires corrective actions to be initiated if the number of cycles exceeds the number assumed in the design. The staff concludes that the components identified in WCAP-14575-A will be adequately addressed by the applicant's TFMP.

The WOG issued the generic Topical Report WCAP-14574-A, "License Renewal Evaluation: Aging Management Evaluation for Pressurizers," to address aging management of pressurizers. Renewal applicant action item 1 of the accompanying staff SE requests that a license renewal applicant demonstrate that the pressurizer sub-component CUFs remain below 1.0 for the period of extended operation. Table 2-10 of WCAP 14574-A indicates that the ASME Section III Class 1 fatigue CUF criterion could be exceeded at several pressurizer sub-component locations during the period of extended operation. WCAP-14574-A also identified recent unanticipated transients that were not considered in the original ASME Section III Class 1 fatigue analyses. By letter dated January 28, 2002, the staff requested, in RAI 4.3-4, that the applicant provide the following information:

- an evaluation to confirm that the additional transients discussed in WCAP-14574-A, not considered in the original design, have been addressed at McGuire and Catawba
- a list of the ASME Section III Class 1 CLB CUFs for the applicable sub-components of the McGuire and Catawba pressurizers specified in Table 2-10 of WCAP-14574-A and the corresponding CUFs for the extended period of operation
- a discussion of the impact of the environmental fatigue correlations provided in NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” and NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,” on the above results

In its response dated April 15, 2002, the applicant indicated that WCAP-14574-A had not been considered in the LRA. However, the applicant indicated that it had reviewed WCAP-14574-A in order to respond to the RAI. Regarding the first issue, the applicant indicated that modified operating procedures had been implemented at McGuire and Catawba to mitigate the effects of insurge/outsurge. In addition, historical plant instrument data were analyzed to determine the insurge/outsurge history both before and after modification of the operating procedures. The applicant indicated that an analysis including these events found that the design CUFs of all components will remain less than 1.0. By letter dated July 9, 2002, the applicant provided the CUFs for the sub-components listed in Table 2-10 of WCAP-14574-A, but did not discuss the impact of the environmental fatigue correlations on these sub-components. Pending completion of the staff’s review of the information provided and assessment of the impact of the environmental correlations for these sub-components, this issue was characterized as SER open item 4.3-1.

In its letter dated July 9, 2002, the applicant identified several pressurizer sub-components with relatively high design CUFs for McGuire and Catawba. These sub-components include the shell, spray nozzle, lower head heater penetration and nozzle weld, instrument nozzle, and surge nozzle. An assessment by the staff applying a conservative estimate of the environmental factor to these locations indicates that the CUFs may exceed 1.0 during the period of extended operation. Similar results were obtained by previous license renewal applicants with Westinghouse NSSS designs. A discussion of these assessments is contained in the staff SERs related to the license renewal of the Turkey Point and North Anna/Surry facilities.

The Turkey Point and North Anna/Surry license renewal applicants used a combination of quantitative and qualitative assessments to argue that the actual CUFs, including environmental effects, are not expected to exceed 1.0 during the period of extended operation. If similar quantitative and qualitative assessments were performed for McGuire and Catawba, the staff would expect similar results to be obtained because McGuire and Catawba are Westinghouse NSSS designs, like Turkey Point, North Anna and Surry. These applicants also committed to monitor the fatigue usage, including environmental effects, of the surge line nozzle during the period of extended operation. The staff concluded that the surge line nozzle is an acceptable sample component to represent environmental effects on the pressurizer sub-components during the period of extended operation.

As discussed later in this SER, the applicant has committed to perform further evaluation of the surge line nozzle during the period of extended operation. The staff concludes that the applicant can use the surge line nozzle evaluation as a representative sample to address environmental effects on pressurizer sub-components for McGuire and Catawba during the period of extended operation. If the further evaluation of the surge line identifies the need for additional actions during the period of extended operation, then the applicant should demonstrate the acceptability of pressurizer sub-components, considering environmental fatigue effects, as part of its corrective action. On the basis of the staff's review documented above, open item 4.3-1 is closed.

The WOG has issued the generic Topical Report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals," to address aging management of the reactor vessel internals. Renewal applicant action item 11 of the accompanying staff SE indicates that the fatigue TLAA of the reactor vessel internals should be addressed on a plant-specific basis. In the LRA, the applicant indicates that the TFMP will assure that component fatigue analyses will remain within their design values for the period of extended operation. By letter dated January 28, 2002, the staff requested, in RAI 4.3-2, that the applicant list the transients that contribute to the fatigue usage for each component listed in Table 3-3 of WCAP-14577, Revision 1-A, and discuss how the TFMP monitors these transients.

In its response dated April 15, 2002, the applicant indicated that WCAP-14577, Revision 1-A had not been considered in the LRA. The applicant stated that no TLAAs were identified for the McGuire or Catawba reactor internals, and that the reactor vessel internals were designed to ASME Section III, Class 2 criteria, which specified no time- or cycle-dependent requirements for the internals. The applicant did indicate that the rod cluster guide tube pins at McGuire and Catawba were replaced, and the replacement pins were analyzed for fatigue considering a 60-year design life. The applicant further indicated that the transients that contribute to the fatigue usage are included in the TFMP. The staff considers the applicant's response acceptable.

The applicant's TFMP tracks transients and cycles of RCS components that have explicit design transient cycles to assure that these components stay within their design basis. Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December 1999, concluding the following:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to manage the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in

> 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

Section 4.3.1.2 of the LRA discusses the applicant's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion indicates that the applicant's evaluation will use method 2 contained in draft EPRI Report MRP-47. The applicant provided a discussion of its proposed implementation of the EPRI Report MRP-47 guidelines. The applicant's proposed evaluation will include a sample of 6 to 10 locations selected for assessment. Locations for consideration will include the NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," locations and other locations expected to have high usage factors when considering environmentally assisted fatigue (EAF).

The staff is currently reviewing EPRI Report MRP-47 and has not yet endorsed the guidelines presented in the report. Consequently, by letter dated January 28, 2002, the staff requested, in RAI 4.3-5, that the applicant provide additional information regarding the evaluation of reactor water environmental effects. Specifically, the staff requested the following:

- confirmation that the environmental fatigue correlations contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," will be used in the evaluation

- design basis usage factors for each of the six component locations listed in NUREG/CR-6260

- detailed technical evaluation which demonstrates that the proposed inspections provide an adequate basis for detecting fatigue cracking before such cracking leads to through wall cracking or pipe failure [The detailed technical evaluation was required to be sufficiently conservative to address all uncertainties associated with the technical evaluation (e.g., fatigue crack initiation and detection, fatigue crack size, and fatigue crack growth rate considering environmental factors). As an alternate to the detailed technical evaluation, a commitment was needed to monitor the fatigue usage, including environmental effects, during the period of extended operation, and to take corrective actions, as approved by the staff, if the usage was projected to exceed 1.0. The detailed technical evaluation was required because the applicant had indicated that ASME Section XI flaw evaluation and inspection procedures could be used as an alternate method to manage environmental fatigue. The NRC staff indicated that it has not endorsed a procedure on a generic basis which allows for ASME Section XI inspections in lieu of meeting the fatigue usage criteria.]

- additional data and evaluations which demonstrate that (1) there is sufficient margin in the procedure to account for material variability and experimental data scatter, size effects, surface finish effects, and loading history, and (2) environmental effects and surface effects are not independent effects. [As an alternative, the applicant's procedure should be revised to eliminate the Z factor. This information was needed because the applicant's procedure indicated that the environmental factor would be adjusted by a Z factor to take credit for moderate environmental effects in the existing ASME fatigue curves. The staff considers the use of the Z factor an open issue regarding implementation of the EPRI procedure.]

In its response dated April 15, 2002, the applicant confirmed that the environmental fatigue correlations in NUREG/CR-6583 and NUREG/CR-5704 will be used in the evaluations. Although the applicant indicated that NUREG/CR-6260 locations applicable to McGuire and Catawba correspond to those identified for a newer Westinghouse plant, the applicant did not provide the design usage factors for these locations in its RAI response. However, the applicant did provide, in subsequent electronic correspondence dated May 23, 2002 (ADAMS Accession No. ML023290427), a table of CUFs for newer-vintage Westinghouse plant locations identified in NUREG/CR-6260. This table was attached as an enclosure to a June 4, 2002, conference call summary, summarized by memorandum dated June 19, 2002. By letter dated July 9, 2002, the applicant provided these data in official correspondence. Additionally, the staff requested that the applicant provide design stresses and fatigue usage factors associated with the Catawba charging system flow changes discussed previously in this SER. Pending the staff's receipt of information pertaining to the Catawba charging flow changes and completion of the staff's review of the environmental impact on the fatigue usage for plant locations identified in NUREG/CR-6260, this issue was characterized as SER open item 4.3-2.

In its response to this SER open item, dated October 2, 2002, the applicant discussed the Catawba charging system flow transients. The applicant indicated that a review of the existing engineering calculations found that the charging and letdown flow change transients cause insignificant fatigue usage. The staff also had reviewed the engineering calculations during a September 18, 2002, meeting with the applicant (summarized by memorandum dated November 18, 2002) and confirmed that the Catawba charging flow transients were determined to cause insignificant fatigue usage. On the basis of the staff review of the applicant's engineering calculations for the Catawba charging system, this part of open item 4.3-2 is closed.

In its July, 9, 2002, submittal, the applicant identified relatively high design basis fatigue usage factors for the RPV outlet nozzle, surge line hot leg nozzle, charging nozzle, and safety injection nozzle for McGuire and Catawba. An assessment by the staff, applying a conservative estimate of the environmental factor to these locations, indicates that the CUFs of these components may exceed 1.0 during the period of extended operation. The applicant has committed to perform further evaluations of these components, considering environmental effects, prior to the period of extended operation in response to SER open item 4.3-4. This commitment is included in the revised FSAR supplements for Catawba and McGuire submitted by the applicant in a letter dated October 2, 2002. On the basis of the applicant's commitment to perform further evaluations of impact of the environment on the fatigue usage of these components, this part of open item 4.3-2 is closed.

The applicant agreed not to use the flaw tolerance/inspection procedures specified in Note 1 unless such procedures have been accepted by the NRC. In addition, the applicant agreed to revise the procedure specified in LRA Section 4.3.1.2 to set Z equal to 1.0. The staff finds these commitments acceptable.

In LRA Section 4.3.2, "ASME Section III, Class 2 and 3 Piping Fatigue," the applicant indicated that, for license renewal, all thermal cycle count assumptions for the non-Class 1 mechanical systems were conservatively re-validated for 60 years of operation. ASME Section III, pertaining to Class 2 and 3 piping design criteria, requires that a reduction factor be applied to the allowable bending stress range if the number of full range thermal cycles exceeds 7000. ANSI B31.1 contains the same requirement. The applicant indicated that two locations at

McGuire and Catawba could reach the 7000-cycle limit during the period of extended operation. By letter dated January 28, 2002, the staff requested, in RAI 4.3-7, that the applicant identify these locations and indicate how the number of expected cycles was determined. The staff also requested that the applicant describe the re-evaluation that was performed to demonstrate that these locations will be acceptable for the period of extended operation.

In its response dated April 15, 2002, the applicant stated that the number of expected thermal cycles of ASME III, Class 2 and 3 piping was determined by a conservative operational review to identify susceptible locations. The applicant stated that it had performed a comparison of actual operating experience to the design thermal cycle assumptions, including a projection of assumed future cycles, to determine the number of expected thermal cycles for 60 years of operation. The applicant indicated that the starting air compressor discharge piping in the diesel generator starting air system at McGuire and Catawba is expected to exceed 7000 cycles during the period of extended operation because of the frequent cycling of the air compressor. The applicant's response indicated that a portion of the drain piping in the main steam system at McGuire was projected to exceed 7000 cycles during the period of extended operation due to significant thermal cycling during startup. In addition, the pressurizer liquid sample piping at Catawba was frequently used to sample boron. The applicant indicated that the stresses in these piping systems were within Code limits after conservative stress range reduction factors were applied. The staff finds the response acceptable because the applicant indicated that the piping systems will continue to meet acceptable Code limits during the period of extended operation.

The LRA does not address the issue of underclad cracks. The WOG submitted for staff review Topical Report WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants (MUHP-6110)" by letter dated March 1, 2001. WCAP-15338 indicates that underclad cracks are confined to forging materials, SA 508, Class 2 and 3. Topical Report WCAP-15338 also indicates that underclad cracks were observed in SA 508, Class 3 nozzles clad with multiple-layer, strip electrode, submerged-arc welding processes where preheating and post-heating were applied to the first layer but not to the subsequent layers. By letter dated January 28, 2002, the staff requested, in RAI 4.3-6, that the applicant provide additional information regarding the susceptibility of the McGuire/Catawba vessel forgings to underclad cracking. Subsequently, the staff identified the following information in Catawba UFSAR Section 5.3.1.4:

> **<u>Section 5.3.1.4, "Special Controls for Ferretic and Austenitic Stainless Steels," page 5.3-2</u>**
> **Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Allow Steel Components (5/73)"**
>
> <u>Discussion</u>
>
> Westinghouse practices achieve the same purpose as Regulatory Guide 1.43 by requiring qualification of any high head input process, such as the submerged-arc wide-strip welding process and the submerged-arc 6-wire process used on ASME SA-508, Class 2, material, with a performance test as described in Regulatory Position 2 of the guide. No qualifications are required by the regulatory guide for ASME SA-533 material and equivalent chemistry for forging grade ASME SA-508, Class 3, material. The fabricator monitors and records the weld parameters to verify agreement with the parameters established by the procedure qualification as stated in Regulatory Position C.3.

Since Regulatory Guide (RG) 1.43 contains guidance for control of stainless steel cladding of low-alloy steel components, the staff concluded that underclad cracking was not a concern for Catawba 1 and 2. The staff was unable to verify that the same controls were in effect for the McGuire units. In its response dated April 15, 2002, the applicant did not provide adequate justification for the staff to conclude that all the McGuire reactor vessel forgings are not susceptible to underclad cracks.

By letter dated June 26, 2002, the staff provided a list of potential open items to the applicant and requested that the applicant provide written responses to resolve those open or confirmatory items that it considered reconcilable. RAI 4.3-6 was characterized as open for the McGuire units. In its response dated July 9, 2002, the applicant provided information that was excerpted from a letter dated May 12, 1980, in which the NRC requested information on the McGuire reactor vessel nozzle base metal material, clad process type, heat input, and manufacturer or subcontractor who fabricated the vessel and applied the nozzle cladding. The applicant also provided the following excerpt from a letter dated July 17, 1980, which transmitted the NRC's safety evaluation of information subsequently provided by Duke in a letter dated June 6, 2002:

> We have determined that the McGuire Unit No. 2 reactor vessel was fabricated by Rotterdam-Nuclear of the Netherlands using procedures for welding and pre- and post-clad heat treatments that increase the potential for underclad cracking. For this reason, we require that augmented ultrasonic examination for underclad cracking be performed on the McGuire Unit No. 2 reactor vessel nozzles prior to issuance of an operating license. The inspections should be conducted using techniques that have been designed to detect underclad cracks. These techniques previously have been used at Sequoyah 1, North Anna 2 and Salem 2. The McGuire Unit No. 1 vessel was fabricated by Combustion Engineering using welding heat treat practices expected not to cause underclad cracking. Therefore, we do not require that augmented preservice inspections be performed on the Unit No. 1 vessel. In the future augmented ultrasonic examinations will be required for a reactor vessel whose nozzles were clad in the U. S., but only as part of a program to verify that cladding heat treatments used by U. S. manufacturers do not result in underclad cracking.

Based upon this excerpt from the staff's safety evaluation regarding the reactor vessel nozzles at McGuire, the staff concludes that the applicant need not address this issue for McGuire 1. However, underclad cracking remains a concern for McGuire 2. The applicant is relying upon ultrasonic inspection for resolution of this issue. However, the staff believes that ultrasonic inspection is not effective at detecting defects of the size generated by this phenomenon. Therefore, this issue can be resolved for McGuire 2 only by analysis. For this reason, this issue was characterized as SER open item 4.3-3 and applied to McGuire 2 only.

In its response to SER open item 4.3-3, dated October 28, 2002, the applicant stated that Duke had compared the number of design cycles and transients used in the analysis contained in WCAP-15338 with the applicable number of design cycles and transients contained in McGuire Unit 2 design documents and verified that WCAP-15338 bounds the number of operating cycles and transients not only for McGuire 2 but also for Catawba Unit 1,[1] whose RV is also fabricated

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[1] As stated earlier in the evaluation provided in this section (page 4-14), the staff determined that RV underclad cracking was not an applicable effect for Catawba 1 because the RV forgings had been welded together in accordance with the recommended practices of Regulatory Guide (RG) 1.43, which, if implemented, should mitigate the amount of underclad cracking in the RV. However, the applicant has also indicated that the number of design cycles and transients in WCAP-15338 also bounds the number

from SA 508 Class 2 forging segments. In its response to SER open item 4.3-3, the applicant provided an FSAR supplement summary description to reflect that fatigue analysis in WCAP-15338 for RV underclad cracks in Westinghouse designed reactors was bounding for the evaluation for RV underclad cracks at McGuire 2. Since the conclusions in WCAP-15338 are bounding and applicable to the evaluation of fatigue-induced crack growth of underclad cracks in the McGuire 2 RV, the staff concludes that the applicant has demonstrated that its analysis for postulated underclad cracks in the McGuire 2 RV remains valid for the extended operating period for McGuire 2, and that therefore the applicant's TLAA for RV underclad cracks at McGuire 2 is acceptable pursuant to 10 CFR 54.21(c)(1)(i).

As discussed previously, the applicant relies on the TFMP to manage the thermal fatigue design basis to assure that the analyses remain valid for the period of extended operation. The staff review of the TFMP focused on how the program manages fatigue through effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, acceptance criteria, monitoring and trending, corrective actions, confirmation process, administrative controls and operating experience.

[Program Scope] The scope of the program includes the reactor coolant pressure boundary Class 1 components including piping connected to the RCS addressed by NRC Bulletins 88-08 and 88-11, replacement steam generators, components evaluated using fracture mechanics analyses, and four Catawba heat exchangers. The staff considers the scope of the program, which includes components with analyses that explicitly addressed thermal fatigue transient limits, acceptable.

[Preventive and Mitigative Actions] The applicant indicates that the TFMP ensures that the thermal fatigue design basis remains valid for the period of extended operation. The TFMP accomplishes this through the monitoring and tracking of transients used in the fatigue analyses of components. The staff did not identify a need for any further actions.

[Parameters Monitored or Inspected] The program monitors the transients used in the analyses of the components. The staff considers this monitoring appropriate because the program objective is to ensure that the analyses remain valid for the period of extended operation.

[Detection of Aging Effects] The program monitors the number of design transients used in the fatigue analysis of components to provide assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff did not identify a need for any further actions.

[Monitoring and Trending] The program monitors the number of design transients used in the fatigue analysis of components. The program also monitors the pressure and temperature profiles of these transients. The monitored values are compared to design values. The staff considers this monitoring appropriate because the program objective is to ensure that the analyses remain valid for the period of extended operation.

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of design cycles and transients projected for Catawba 1 through the expiration of the extended period of operation. Each of these bases provide reasonable assurance that underclad cracking is not an issue for the Catawba 1 RV.

[Acceptance Criteria]  The acceptance criteria are the number of cycles of each transient assumed in the design analyses and the temperature and pressure profiles for each transient. The staff considers this criteria acceptable because the program objective is to ensure that the analyses remain valid for the period of extended operation.

[Corrective Actions and Confirmation Process]  The applicant indicates that, if the number of transient cycles approaches the assumed bases for the plant design, further analysis will be performed to account for the number of these cycles. The applicant also indicates that the corrective action program is triggered if the temperature or pressure profiles exceed the design limits.  The staff's evaluation of the corrective action program and confirmation process is documented in Section 3.0.4 of this SER.

[Administrative Controls]  The applicant indicates that implementation procedures are reviewed, approved, and maintained as controlled documents in accordance with the station's work process.  The staff's evaluation of the administrative controls is documented in Section 3.0.4 of this SER.

[Operating Experience]  The applicant indicates that thermal fatigue transients have been tracked since operation began at both McGuire and Catawba.  The staff identified open item 4.3-1 regarding the applicant's response to issues identified in Topical Report WCAP-14574-A.  Pending the completion of the staff's review of this issue, the staff is unable to conclude that operating experience has been adequately considered in the program.

**4.3.3 FSAR Supplement**

The applicant provided a McGuire FSAR supplement for Section 3.9.2 and a Catawba FSAR supplement for Section 3.9.3, which indicate that stress range reduction factors were used in the evaluation of ASME Class 2 and 3 piping systems.  The applicant also provided a McGuire FSAR supplement for Section 5.2.1 and a Catawba FSAR supplement for Section 3.9.1 to indicate that both TFMP will continue to manage thermal fatigue into the period of extended operation.  However, the applicant did not describe its commitment to evaluate the effects of the environment on fatigue of reactor coolant system pressure boundary components, and the applicant did not provide a description of its TFMP.  Because these items should be described in a revised FSAR supplement, this issue was characterized as SER open item 4.3-4.

In its response dated October 28, 2002, the applicant provided FSAR supplements for Catawba and McGuire.  The revised FSAR supplements provided summary descriptions of the TFMP for McGuire and Catawba.  The revised FSAR supplements also included the applicant's commitment to perform additional evaluations of the effects of environmental fatigue on the critical locations identified in NUREG/CR-6260 prior to the period of extended operation.  On the basis of the applicant's revised FSAR supplements for McGuire and Catawba, open item 4.3-4 is closed.

The staff concludes that the summary description of the applicant's actions to address metal fatigue for the period of extended operation provided in the revised McGuire and Catawba FSAR supplements satisfy the requirements of 10 CFR 54.21(d).

### 4.3.4 Conclusions

On the basis of its evaluation of McGuire and Catawba components, the staff concluded that the fatigue analysis of ASME Section III, Class 2 and 3 piping will remain valid for 60 years of operation. The applicant also has a TFMP to maintain a record of the transients used in the fatigue analyses of ASME Section III, Class 1 components and other components where thermal fatigue limits were explicitly addressed at McGuire and Catawba, and to ensure that the process will continue during the period of extended operation. The TFMP will provide assurance that the fatigue design of these components remains valid for the period of extended operation.

On the basis of its review, and with the resolution of SER open items 4.3-1, 4.3-2, 4.3-3, and 4.3-4, the staff concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1).

## 4.4 Environmental Qualification of Electrical Equipment

The aging (or qualified life) analysis for electrical components, included as part of the EQ program required by 10 CFR 50.49, that involve time-limited assumptions as defined by the current operating term for the McGuire and Catawba plants (i.e., 40 years), meets the 10 CFR 54.3 definition for TLAAs. The electrical components are thus considered TLAAs for license renewal. The EQ program, together with other plant programs/processes, has been evaluated, pursuant to 10 CFR 54.21(c)(1)(iii), to determine if they will adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation.

In LRA Section 4.4, "Environmental Qualification (EQ) of Electric Equipment," the applicant described the technical bases and justification for why the McGuire and Catawba EQ Program, together with other plant programs/processes, adequately manages the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff reviewed this section of the LRA to determine whether the applicant had demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed, through the McGuire and Catawba EQ Program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

### 4.4.1 Technical Information in the Application

The McGuire and Catawba EQ Program meets the requirements of 10 CFR 50.49. Section 50.49 of 10 CFR defines the scope of components to be included, requires the preparation and maintenance of a list of in-scope components, and requires the preparation and maintenance of a qualification file that includes component performance specifications, electrical characteristics, and the environmental conditions to which the components could be subjected. Section 50.49(e)(5) of 10 CFR contains provisions for aging that require, in part, consideration of all significant types of aging degradation that can affect component functional capability. Section 50.49(e) of 10 CFR also requires replacement or refurbishment of components not qualified for the current license term prior to the end of designated life, unless additional life is established through ongoing qualification. Section 50.49(f) of 10 CFR establishes four methods of demonstrating qualification for aging and accident conditions. Sections 50.49(k) and (l) of 10 CFR permit different qualification criteria to apply based on plant and component vintage. Compliance with 10 CFR 50.49 provides reasonable assurance that the component can perform its intended functions during accident conditions after experiencing the effects of inservice aging.

The McGuire and Catawba EQ Program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation.

Under 10 CFR 54.21(c)(1)(iii), the McGuire and Catawba EQ Program, which implements the requirements of 10 CFR 50.49, is viewed as an aging management program for license renewal. Important attributes for the reanalysis of an aging evaluation include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria and corrective actions (if acceptance criteria are not met).

The reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed pursuant to 10 CFR 50.49(e) as part of the McGuire and Catawba EQ Program. While a component's life-limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to McGuire and Catawba quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods: The McGuire and Catawba EQ Program uses the same analytical models in the reanalysis of an aging evaluation as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (i.e., normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5. The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods: Reducing excess conservatism in the component service conditions (e.g., temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis per the McGuire and Catawba EQ Program. Temperature data used in an aging evaluation should be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (1) directly applying the plant temperature data in the evaluation, or (2) using the plant temperature data to demonstrate conservatism when using plant design temperatures for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cyclical aging.

Underlying Assumptions: McGuire and Catawba EQ Program component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modifications and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Action: Under the McGuire and Catawba EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification cannot be extended by reanalysis, the component must be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (i.e., sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

In addition to these important attributes for reanalysis of the aging evaluation, the McGuire and Catawba EQ Program includes the attributes described below:

<u>McGuire and Catawba EQ Program</u>

[Program Scope] The McGuire and Catawba EQ Program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49.

[Preventive Actions] Section 50.49 of 10 CFR does not require actions that prevent aging effects. McGuire and Catawba EQ Program actions that could be viewed as preventive actions include (1) establishing the component service condition tolerance and aging limits (e.g., qualified life or condition limit), and (2) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain component aging effects within the bounds of the qualification basis.

[Parameters Monitored or Inspected] The qualified life of a component in the McGuire and Catawba EQ Program is not based on condition or performance monitoring. However, pursuant to Regulatory Guide 1.89, Rev. 1, such monitoring programs are an acceptable basis to modify a qualified life through reanalysis. Monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

[Detection of Aging Effects] Section 50.49 of 10 CFR does not require the detection of aging effects for inservice components. As implemented by the McGuire and Catawba EQ Program, monitoring or inspection of certain environmental conditions or component parameters may be used to ensure that the component is within the bounds of its qualification basis, or as a means to modify the qualified life.

[Monitoring and Trending] Section 50.49 of 10 CFR does not require monitoring and trending of component condition or performance parameters of inservice components to manage the effects of aging. McGuire and Catawba EQ Program actions that could be viewed as monitoring include monitoring how long qualified components have been installed. Monitoring or inspection of certain environmental, condition, or component parameters may be used to ensure that a component is within the bounds of its qualification basis or as a means to modify the qualification.

[Acceptance Criteria] Section 50.49 of 10 CFR acceptance criteria, as implemented by the McGuire and Catawba EQ Program, are that an inservice EQ component is maintained within the bounds of its qualification basis, including (1) its established qualified life and (2) continued qualification for the projected accident conditions. Section 50.49 of 10 CFR requires refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.

[Corrective Action and Confirmation Process] If a component in the McGuire and Catawba EQ Program is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the McGuire and Catawba corrective action program, pursuant to 10 CFR 50, Appendix B.

[Administrative Controls] The McGuire and Catawba EQ Program is implemented through the use of station policy, directives, and procedures. The McGuire and Catawba EQ Program will continue to comply with 10 CFR 50.49 throughout the renewal period, including development and maintenance of qualification documentation demonstrating reasonable assurance that a component can perform required functions during harsh accident conditions. McGuire and Catawba EQ Program documents identify the applicable environmental conditions for the component locations. McGuire and Catawba EQ Program qualification files are maintained at McGuire and Catawba in an auditable form for the duration of the installed life of the component. McGuire and Catawba EQ Program documentation is controlled under the station's quality assurance program.

[Operating Experience] EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of inservice aging.

Based on the above described attributes for reanalysis of the aging evaluation and EQ program, the applicant concluded that the McGuire and Catawba EQ Program has been demonstrated to be capable of programmatically managing the qualified lives of the components falling within the scope of the program for license renewal. The continued implementation of the McGuire and Catawba EQ Program provides reasonable assurance that the aging effects will be managed and that components falling within the scope of the EQ Program will continue to perform their intended functions for the period of extended operation. This result meets the requirement of 10 CFR 54.21(c)(1)(iii).

### 4.4.2 Staff Evaluation

The staff reviewed the information in Sections 4.4, 4.4.1, 4.4.2, and 4.4.3 of the LRA to determine whether the applicant has demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed through their existing EQ program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

The applicant is required to have an EQ program that meets the requirements of 10 CFR 50.49. The staff, therefore, agrees with the applicant’s conclusion that their EQ program, together with other plant programs/processes, will adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff therefore concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that their EQ program, together with other plant programs/processes, will adequately manage the effects of aging on the intended functions and can be considered an acceptable aging management program for license renewal.

Generic Safety Issue (GSI) -168, Environmental Qualification of Electrical Equipment

This GSI was developed to address environmental qualification of electrical equipment. By letter from C. Grimes (NRC staff) to D. Walters (NEI), dated June 2, 1998, the staff issued the following guidance to the industry:

- GSI-168 issues have not been identified to a point that a license renewal applicant can be reasonably expected to address these issues specifically at this time
- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation

For the purpose of license renewal, there are three options for addressing issues associated with a GSI, as discussed in the statement of considerations (SOC) accompanying the final rule, 60 FR 22484, May 8, 1995:

(1) If the issue is resolved before the renewal application is submitted, the applicant can incorporate the resolution into the LRA.
(2) An applicant can submit a technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging.
(3) An applicant can develop a plant-specific aging management program that incorporates a resolution to the aging issue.

The applicant did not provide information in Section 4.4 to address the GSI-168 options. In electronic correspondence from the applicant, dated June 17, 2002 (ADAMS Accession No. ML022200637), Duke provided the following account of GSI-168 as it applies to McGuire and Catawba:

> As discussed in SECY-93-049, the staff reviewed significant license renewal issues and found that several were related to environmental qualification (EQ). A key aspect of these issues was whether the licensing bases should be reassessed or enhanced in connection with license renewal, and whether this reassessment should be extended to the current license term. In late 1993, the Commissioners instructed the staff that the current EQ licensing basis must be used in the license renewal period and that any EQ concerns identified by the staff during the review of EQ for license renewal should be evaluated for the effect on current licenses, independent of license renewal.
>
> The NRC Staff's EQ Task Action Plan (EQ-TAP) was initiated to address the adequacy of current EQ practices. Upon completion of the EQ-TAP review, the focus of Staff concerns was limited to issues related to the adequacy of accelerated aging practices in existing qualifications, and the lack of a “feedback mechanism” in EQ programs (i.e., programmatic requirements to determine the current condition of EQ equipment so that it can be evaluated against the assumptions and parameters for qualification). The EQ-TAP was subsequently closed and six remaining open issues were incorporated into GSI 168 for management tracking purposes. The EQ-TAP review did not identify any generic safety issues related to these six open issues.
>
> NRC guidance for addressing GSI 168 for license renewal is contained in a June 1998 letter to NEI. In this letter, the NRC states:
>
> With respect to addressing GSI 168 for license renewal, until completion of an ongoing research program and staff evaluations, the potential issues associated with GSI 168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the SOC is to provide a technical rationale demonstrating that the current licensing basis for EQ pursuant to 10 CFR 50.49 will be maintained in the period of extended operation. Although the SOC also indicates that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time.
>
> Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for McGuire and Catawba. The McGuire and Catawba EQ program evaluations contained in Section 4.4 of the Application are considered to be the technical rationale that the current licensing basis will be maintained during the period of extended operation. Consistent with the above NRC guidance, no additional information is required to address GSI 168 in a renewal application at this time.

By letter dated July 9, 2002, the applicant provided this same response in official correspondence. The staff finds that the applicant has submitted, in accordance with the SOC, a technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging. However, the staff requested that the applicant also indicate that it would monitor updates to NUREG-0933, “A Prioritization of Generic Safety Issues,” for revisions to GSI-168 during the review of its application, or that it would supplement its license renewal application if the issues associated with GSI-168 become defined, such that providing the options or pursuing one of the other approaches described in the SOC becomes feasible. Pending the staff’s receipt of this information, this issue was characterized as confirmatory item 4.4-1.

In response to confirmatory item 4.4-1, dated October 2, 2002, the applicant proposed the following alternative commitment:

> If the staff issues a generic communication that defines the issues associated with GSI-168 such that providing the options or pursuing one of the other approaches described in the SOC to 10 CFR 54 (FR Vol. 60, No. 88, May 8, 1995) becomes feasible, then Duke will supplement its license renewal application. The staff generic communication should be issued prior to November 1, 2002 in order for Duke to evaluate its contents, prepare a response as a current licensing basis change, if any is required, and provide a supplement to the application (if necessary) in sufficient time for the staff to complete its review prior to the scheduled issuance of the safety evaluation report for license renewal January 6, 2003.

The resolution to GSI-168 was not issued by the staff prior to November 1, 2002; thus, the applicant's proposed alternative commitment is their original commitment that was stated above in their June 17, 2002, response to GSI-168. Pursuant to the requirements of 10 CFR Part 50, the staff will evaluate the applicant's compliance to the resolution of GSI-168 after its issuance and prior to the extended period of operation as part of 10 CFR 50.49. Resolution of GSI-168 pursuant with Part 50 meets the requirement of 10 CFR 54.21(c)(1)(iii) and is therefore considered acceptable. Confirmatory item 4.4-1 is considered closed.

### 4.4.3 FSAR Supplement

In LRA Appendix A, pages A.1-5 and A.2-7, the applicant states that the existing EQ process, in accordance with 10 CFR 50.49, will adequately manage aging of EQ equipment for the period of extended operation. This statement is consistent with the conclusion that plant EQ programs, which implement the requirements of 10 CFR 50.49, are viewed as acceptable aging management programs for license renewal under 10 CFR 54.21(c)(1)(iii). This statement thus provides a summary description of the programs and activities for the evaluation of TLAA for the period of extended operation for electrical components, meets the requirements of 10 CFR 54.21(d), and is considered acceptable.

### 4.4.4 Conclusions

The staff has reviewed the information in Sections 4.4, 4.4.1, 4.4.2, and 4.4.4 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the effects of aging on the intended function(s) of electrical components, that meet the definition for TLAA, as defined in 10 CFR 54.3, will be adequately managed during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii). The staff concludes that the FSAR supplement contains a summary description of the programs and activities for the evaluation of TLAA for the period of extended operation as required by 10 CFR 54.21(d).

## 4.5 Concrete Containment Tendon Prestress

### 4.5.1 Technical Information in the Application

The applicant stated that this topic is not applicable to the McGuire and Catawba ice condenser containments. Ice condenser containments do not use prestressed tendons.

### 4.5.2 Staff Evaluation

The staff concurs with the applicant that this topic is not applicable, and prestress of the concrete containment tendons at the McGuire and Catawba plants is therefore not a TLAA.

### 4.5.3 Conclusions

The staff finds the applicant's statement that this topic is not applicable to McGuire and Catawba acceptable.

## 4.6 Containment Liner Plate, Metal Containments, and Penetration Fatigue Analysis

### 4.6.1 Technical Information in the Application

The applicant stated that McGuire and Catawba have ice condenser metal containments, and therefore do not have containment liner plates, like prestressed concrete containments. The topic of fatigue analysis for containment liner plates is therefore not applicable to these plants.

The McGuire and Catawba ice condenser containments are steel containment vessels (SCVs), described in Section 2.4 of the LRA. The Design Code of Record for the McGuire SCV is the "ASME Boiler & Pressure Vessel Code," Section III, Subsection B, 1968 Edition, including all addenda and code cases through the summer of 1970. The Code of Record for Catawba is the "ASME Boiler & Pressure Vessel Code," Section III. Subsection NE, 1971 Edition, including all addenda through the summer of 1972.

The SCV contain piping through-wall hot and cold mechanical penetration assemblies. Typical hot penetration assemblies are shown in the McGuire and Catawba UFSARs. The hot penetrations consist of the process line and flued head, the guard pipe, and the expansion bellows. The bellows are designed to accommodate process line thermal expansions and displacements between the SCV and the reactor building due to cyclic thermal expansion, seismic movements, and containment test conditions, and to act as barriers against the release of fission products during design basis events. Fatigue is a progressive failure of a structural part under repeated, cycling, or fluctuating loads. Because of the bellows design, the bellows absorb the cyclic piping loads that could cause fatigue and are not transferred to the SCV. Therefore, no fatigue analysis was required for the SCV, and containment fatigue is not a TLAA for either McGuire or Catawba.

All bellows expansion joints are of two-ply construction with a wire mesh between plys for testability of the bellows and the bellows welds to the piping. The McGuire bellows were manufactured, installed, and examined in accordance with paragraph NC-3649 of the ASME Code, Section III, 1971 Edition. The design requirements are contained in McGuire engineering documents. As part of the design, the Code required the manufacturer to consider combined stresses due to pressure and relative displacement due to thermal expansion. The cyclic life data for the bellows was based on actual tests, where bellows designs similar to those installed were cycled to failure. A search of the applicant's engineering records did not locate any manufacturer's records for a fatigue calculation on the original design of the McGuire bellows. During later modifications at McGuire, the bellows manufacturer reviewed the design for revised feedwater penetration movements, and determined that these were good for over 32,000 cycles, considerably in excess of the number of cycles that the bellows would see under normal operating conditions.

For Catawba, the bellows assemblies were manufactured, installed, and examined in accordance with paragraph NC-3649 of the ASME Code, Section III, 1974 Edition. The design requirements for these bellows are contained in Catawba engineering documents. The manufacturer has provided calculations to the applicant for the cyclic life evaluation of the penetrations. These cyclic life values were used by the manufacturer to demonstrate that the design met the Code requirements.

For McGuire and Catawba, the applicant stated that the fatigue analysis of the bellows was determined not to be relevant in making any safety determination. On this basis, the fatigue of bellows is not a TLAA because Criterion 4 of the 10 CFR 54.3 definition of a TLAA was not met. However, the aging effect which could result from cyclic fatigue, cracking, has been identified as an aging effect for the bellows, requiring management for the period of extended operation. Local leak rate testing has been identified as the general program that includes managing of cracking of the bellows. Local leak rate testing is discussed as part of LRA Appendix B.3.8, Containment Leak Rate Testing Program.

### 4.6.2 Staff Evaluation

By letter dated January 28, 2002, the staff requested, in RAI 4.6-1, that the applicant provide a detailed justification for determining that a fatigue TLAA was not required for the SCV for loadings resulting from operating transients, peak containment internal pressure resulting from the design basis LOCA, design basis safe shutdown earthquake (SSE) and leakage rate testing, in addition to the loading resulting from the transient expansions of the bellows. In its response dated March 11, 2002, the applicant stated that the penetration bellows are provided to absorb the loads associated with thermal expansion during operational transients, as well as loads induced during the containment leak testing. Peak containment internal pressure resulting from the design basis LOCA or a design basis SSE are one-time occurrences and not cyclic loads that could cause fatigue failure. The SCV is, therefore, not subjected to cyclic loading and as a result, no fatigue analysis was necessary or performed. The staff finds the response to the RAI acceptable and considers the issue resolved.

Operating experience with containment bellows at both McGuire and Catawba, as reported in LRA Appendix B, Section B.3.8, indicates that leaks were detected during containment leakage tests within 20 years of the start of plant operation. During a conference call between the staff and the applicant on November 20, 2001, summarized by memorandum dated January 10, 2002, the applicant stated that 20 leaking bellows at McGuire and 3 leaking bellows at Catawba were identified during testing. However, these bellows were not replaced as long as leakage did not exceed TS surveillance acceptance criteria. Since the bellows were not replaced, root cause evaluations were not performed to determine the cause (fatigue or SCC) of the leakage. Therefore, the applicant indicated that bellows leakage during the tests could not be attributed definitively to cracking by fatigue and that some other cause may be responsible. By letter dated January 28, 2002, the staff requested, in RAI 4.6-2, that the applicant provide the root cause of the cracking (leakage), since the vendors of the bellows performed cyclic fatigue life evaluations and stated that the life of the bellows is well beyond what the bellows would experience during 40 years of normal plant operation.

In its response to RAI 4.6-2, dated March 11, 2002, the applicant stated that since leakage of the bellows is not attributed to cyclic fatigue, the vendor-analyzed cyclic life remains valid for the period of extended operation. The applicant stated that the leakage during the tests could be attributed to transgranular stress corrosion cracking from contact with a chlorine environment and other causes, such as manufacturing process defects, improper installation, and damage incurred during construction or maintenance activities. The potential leakage that could result from any one of these causes is managed by the Containment Leak Rate Testing Program. This program is identified in Table 3.5-1 of the LRA as a program for managing bellows cracking that would manifest itself during the leakage testing. The staff finds the response to this RAI acceptable and considers this issue resolved.

During the conference call on November 20, 2001, the applicant stated that the calculations and analyses for bellows were not considered relevant in making a safety determination, and that aging of these components would be managed by an aging management program. By letter dated January 28, 2002, the staff requested, in RAI 4.6-3, that the applicant clarify this statement. In its response dated March 11, 2002, the applicant stated that a cyclic analysis of the bellows had been originally performed, but the number of cycles to failure was too large to preclude any safety judgement based on this number. Since this analysis was not used as the basis for any safety judgement, the analysis does not meet Criterion 4 of 10 CFR 54.3 for the definition of a TLAA as defined in 10 CFR 54.3. Because the function of the bellows is within the scope of license renewal, and leaks have been observed at both McGuire and Catawba, cracking has been identified as an aging effect for bellows in Table 3.5-1 of the Application. Aging of penetration bellows will therefore be managed under the Containment Leak Rate Testing Program, discussed in LRA Appendix B, Section B.3.8. The staff's evaluation of the AMP is documented in Section 3.0.3.4 of this SER. Since the Containment Leak Rate Testing Program will reveal leakage (cracks) caused by both fatigue and SCC, the staff finds this response acceptable and considers this issue resolved.

### 4.6.3 FSAR Supplement

The applicant has not provided a supplement to the FSAR, since no new information regarding Section 4.6 was provided in the Application.

### 4.6.4 Conclusions

On the basis of its review, and the responses to the staff requests for additional information, the staff concludes that the applicant has provided adequate information and reasonable assurance to demonstrate that, pursuant to 10 CFR 54.21(c)(iii), the effects of aging of the containment penetration bellows will be adequately managed for the period of extended operation.

## 4.7 Other Plant-Specific Time-Limited Aging Analyses

### 4.7.1 Reactor Coolant Pump Flywheel Fatigue

#### *4.7.1.1 Technical Information in the Application*

The applicant has addressed the TLAA related to fatigue of the reactor coolant pump (RCP) flywheel in Section 4.7.1 of the LRA. The RCP motors at McGuire and Catawba are of the same design. The RCP motors are large, vertical, squirrel cage, induction motors. The motors have flywheels to increase rotational inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway from stresses due to starting the motor. Therefore, this topic is considered as a TLAA for license renewal based on the criteria contained in 10 CFR 54.3.

#### *4.7.1.2 Staff Evaluation*

The applicant estimates that the existing analysis is valid for the period of extended operation, meeting the requirements of 10 CFR 54.21(c)(1).

To estimate the magnitude of fatigue crack growth during plant life, an initial radial crack length of 10 percent of the distance through the flywheel (from the keyway to the flywheel outer radius) was conservatively assumed. The analysis assumed 6000 cycles of pump starts and stops for a 60-year plant life. Reaching 6000 starts in 60 years would require a pump start, on average, every 3.7 days. Since a pump start normally occurs every 200 to 300 days, on average, the design of the reactor coolant pump flywheels is conservative. In addition, crack growth from postulated flaws in each flywheel is only a few mils[2]. The staff concurs with the applicant's assessment and the assumptions made in arriving at the above estimate of pump starts.

#### *4.7.1.3 FSAR Supplement*

The staff has reviewed the changes in the FSAR supplement to existing Section 3.5.2.1 of the UFSAR, provided in Appendices A-1 and A-2 of the LRA for McGuire and Catawba, respectively, and has confirmed that these changes are appropriate because they reflect the validity of the analysis for 60 years of operation.

#### *4.7.1.4 Conclusions*

Because the applicant has demonstrated that the existing analysis for the RCP flywheel is valid for 60 years of operation, the staff concludes that the applicant has provided an acceptable TLAA involving components of the RCP flywheel, as defined in 10 CFR 54.21(c)(1)(i).

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[2] WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination"

### 4.7.2 Leak-Before-Break Analyses

The applicant's leak-before-break analysis is provided in Section 4.7.2 of the LRA.

*4.7.2.1 Technical Information in the Application*

The successful application of leak-before-break (LBB) to the McGuire reactor coolant system primary loop piping is described in Technical Report WCAP-10585, "Technical Basis for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for McGuire Units 1 and 2.“ Likewise, the successful application of LBB to the Catawba reactor coolant system primary loop piping is described in Technical Report WCAP-10546, "Technical Basis for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Catawba Units 1 and 2." These reports provide the technical basis for evaluating postulated flaw growth in the main reactor coolant system piping under normal plus faulted loading conditions.

The applicant stated that there are two considerations for the LBB analysis. The first analysis consideration is that the material properties of the cast austenitic stainless steel can change over time. Cast austenitic stainless steels used in the reactor coolant system are subject to thermal aging during service. This thermal aging causes an elevation in the yield strength of the material and a degradation of the fracture toughness, the degree of degradation being a function of the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation or fully aged point is reached.

NRC-approved Technical Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," presented a detailed study of the effects of thermal aging on piping integrity. This report concluded that the thermal aging process does not significantly change the failure characteristics of the cast stainless steel piping. Technical Reports WCAP-10585 (McGuire) and WCAP-10546 (Catawba) used the findings of this report to make the determination that the material properties in WCAP-10456 were bounding for McGuire and Catawba. Fully aged, lower bounding data were used in performing the LBB evaluation. Additionally, during the license renewal review, the lower bound data in WCAP-10456 were compared to the lower bound data in NUREG-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," and found to be comparable. Therefore, because the original analysis supporting LBB relied on fully aged stainless steel material properties, the analysis does not have a material property time-dependency that requires further evaluation for license renewal.

The second analysis consideration is the accumulation of actual fatigue transient cycles over time that could invalidate the fatigue flaw growth analysis that was done as part of the original LBB analysis. A review of the accumulation of the applicable fatigue transient cycles is considered to meet the TLAA definition. This review was done within the scope of the thermal fatigue management program. The applicant stated that the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the Class I components such that they will continue to perform their intended function(s) for the period of extended operation.

*4.7.2.2 Staff Evaluation*

In the LRA regarding LBB, the applicant intended to demonstrate, through qualitative assessment, that the plant-specific thermal fatigue management program is capable of programmatically managing the assumptions, including the fatigue cycles, in the existing LBB analyses for the period of extended operation. The staff confirmed that the LBB applications for the primary loop piping were approved by the NRC on April 7, 1987, for Catawba 1; on April 23, 1985, for Catawba 2; and on May 5, 1986, for McGuire 1 and 2. The LBB analyses, which provided technical bases for these approved LBB applications, considered the thermal aging of the cast austenitic stainless steel material of the piping, assuming 40 years of operation. Since the primary loop piping contains cast stainless steel material, the LBB application is a TLAA for both plants.

The thermal aging of the cast stainless steel material has been identified as an issue to be reevaluated. This reevaluation revealed that the original LBB analyses had employed the thermal aging properties documented in Technical Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," which bounded the aging material data for Catawba and McGuire. In addition, the applicant performed a comparison of the material aging information in WCAP-10456 with the more recent information in NUREG-6177, and found that the WCAP-10456 toughness data, after long-term aging considering fluence, time, operating temperature, chemical composition, and ferrite content, were bounding. The staff has examined the information in the above-mentioned documents and agreed with the applicant's conclusion that fully aged, lower bounding material property was used in the original LBB analyses. Hence, the properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation.

For the rest of the primary loop piping materials, instead of revising the original analyses by taking into account the fatigue transient cycles for the period of extended operation, the applicant relies on the plant-specific thermal fatigue management program to ensure that the accumulation of the applicable fatigue transient cycles over time would not invalidate the fatigue flaw growth analysis that was performed as part of the original LBB analyses. With this program in place, which calls for constant review of the accumulation of applicable fatigue transient cycles, the applicant concluded that "the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the Class 1 components such that they will continue to perform their intended function(s) for the period of extended operation." The staff has reviewed the thermal fatigue management program and determined that the three monitoring actions of the program are adequate to monitor the applicable set of transients and their limits, and to count the actual thermal cycle transients to ensure that it is within the allowable limits of the defined transients.

In the event that the pressure and temperature profile for a specific transient is outside the parameters for the defined transient set, or the actual cycle count for a transient set is approaching or exceeding the cycle limit assumed in the original LBB analyses, the applicant proposed to take corrective actions, such as conducting ISI activities, implementing plant modifications, and performing revised analyses. The staff considers these measures appropriate and agrees with the applicant's conclusion that this TLAA is in accordance with 10 CFR 54.21(c)(1)(ii), and the continued implementation of the thermal fatigue management program provides reasonable assurance that thermal fatigue will be managed for the primary loop piping and components such that it will continue to perform its intended function for the period of extended operation.

Since the V.C. Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff has been addressing the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds on a generic basis for all currently operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance, (2) assess the current inspection technology, and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in a safety evaluation issued June 14, 2001. The final industry report on this issue has not yet been published. Pending its receipt of the final report and additional UT inspection data from piping involving Alloy 82/182 weld material from the industry, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. Additionally, the staff identified SER open item 3.0.3.10.2-2 and requested the applicant to (1) identify the locations in the McGuire and Catawba RCS piping that contain Alloy 82/182 welds, and (2) describe actions it has taken to address this operating experience as it applies to McGuire and Catawba. The resolution of this open item is documented in Section 3.0.3.10.2 of this SER.

*4.7.2.3 FSAR Supplement*

The applicant provided a McGuire FSAR supplement for Section 5.2.1 and a Catawba FSAR supplement for Section 3.9.1 to indicate that LBB analyses evaluate postulated flaw growth in the primary loop piping of the RCS. In addition to the summary description, the FSAR supplements contain information regarding the consideration of thermal aging of cast austenitic stainless steel and the applicable crack growth calculations under the thermal fatigue management program, which constitute the bases for the staff's acceptance of the applicant's evaluation of the LBB TLAA for the period of extended operation. Therefore, the supplements meet the requirements of 10 CFR 54.21(d) and are considered acceptable.

*4.7.2.4 Conclusions*

The properties for the cast stainless steel piping material are acceptable because they will not degrade below the fully aged properties in the extended period of operation. Furthermore, the thermal fatigue management program is adequate to ensure that allowable limits are maintained. The applicant has proposed to take appropriate corrective actions if the pressure and temperature profile for a specific transient is outside the parameters for the defined transient set, or the actual cycle count for a transient set is approaching or exceeding the cycle limit. With respect to the potential for PWSCC of the 82/182 welds, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. Any measures to be implemented, or any requirements to be imposed, as part of the resolution of the PWSCC issue under 10 CFR Part 50 also will apply during the period of extended operation. Therefore, the staff concludes that the applicant has provided an acceptable TLAA regarding LBB and meets 10 CFR 54.21 (c)(1)(ii).

### 4.7.3 Depletion of Nuclear Service Water Pond Volume Due to Run-Off

The depletion of nuclear service water pond volume due to run-off time-limited aging analysis is not applicable at McGuire. The drainage area serving the McGuire nuclear service water ponds is such that the run-off and resulting sedimentation are negligible. The volume of the McGuire nuclear service water pond has been previously reviewed and accepted by the NRC in the initial McGuire SER, Section 4.2[3].

The depletion of nuclear service water pond volume due to run-off TLAA is applicable to Catawba, which is provided in Section 4.7.3 of the LRA.

#### *4.7.3.1 Technical Information in the Application*

The standby nuclear service water (SNSW) pond is a nuclear safety-related impoundment constructed by placing a dam across a small cove of Lake Wylie. Because of the design of the SNSW pond, an analysis was performed to predict the total loss of volume in the pond due to sedimentation during the 40-year plant life. This analysis is described in the Catawba UFSAR, Section 2.4.8, and the Catawba SER, Section 2.4.4.2. The analysis estimated that the SNSW pond volume would be depleted by about 10 acre-feet of sediment during the 40-year plant life.

Because all of the criteria contained in 10 CFR 54.3 have been met, the sedimentation of the SNSW pond, over time, is a time-limited aging analysis for Catawba Nuclear Station. TLAA demonstration option (iii), which states that the effects of aging will be adequately managed for the period of extended operation, is chosen to manage the SNSW pond sedimentation TLAA. The Standby Nuclear Service Water Pond Volume Program manages the volume of water in the pond.

Catawba TS 3.7.9.1 requires that the water level of the SNSW pond remain greater than or equal to 571 feet mean sea level. This requirement ensures that a sufficient volume of water is available to allow the nuclear service water system to operate for at least 30 days following the design basis LOCA. The SNSW pond’s level is monitored and makeup water is provided should the pond level drop to 571.5 feet. TS 3.7.9 requires immediate makeup to restore the pond level or the station is shut down. The minimum allowable pond level includes a margin to account for evaporation and the use of SNSW pond water for fire protection, assured auxiliary feedwater, assured component cooling makeup, and assured fuel pool makeup for a full 30 days after a postulated accident, according to Section 9.2.5.4 of the Catawba UFSAR.

Catawba UFSAR Figure 9-54 contains the area volume curves which are used in the thermal analysis for the ultimate heat sink. The UFSAR also includes a commitment that soundings will be taken around the SNSW intake structure at 5-year intervals to assure that sediment deposits will not adversely affect the operation of the nuclear service water system. Although an earlier calculation for the volume of the SNSW pond was documented, more recent calculations have been performed which validate the volume of water in the SNSW pond.

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[3] NUREG-0422, “Safety Evaluation Report Related to the Operation of the McGuire Nuclear Station, Units 1 and 2.”

*4.7.3.2 Staff Evaluation*

The applicant has chosen to utilize TLAA demonstration option (iii). The staff evaluation of the TLAA, therefore, focused on how the SNSW Pond Volume Program manages the aging effect of pond volume depletion through 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.

It is noted that corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR, Part 50, Appendix B, and cover all structures and components subject to an aging management review. The staff's evaluation of the applicant's corrective actions, confirmation process and administrative controls is documented in Section 3.0.4 of this safety evaluation report. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

<u>Standby Nuclear Service Water Pond Volume Program</u>

[Program Scope] The scope of the Standby Nuclear Service Water Pond Volume Program includes the volume of water in the SNSW pond. The staff finds the scope of the program acceptable because this is the only commodity in which the aging effect is to be managed.

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

[Parameters Monitored or Inspected] The volume of water in the pond is the only parameter that is monitored. The Standby Nuclear Service Water Pond Volume Program requires a topographic survey of the ponds to determine the topography of the bottom of the SNSW pond. Calculations are then performed using the survey data to determine the volume of water within the SNSW pond. This is acceptable to the staff because this parameter provides an effective means of managing the aging effect of water depletion.

[Detection of Aging Effects] The applicant stated that no actions are taken as part of this program to detect aging effects, and the application is silent in regard to the remedial action that the applicant will take in case a future survey of the topography of the bottom of the pond indicates a reduction in the volume of water due to the buildup of sediment. By letter dated January 28, 2002, the staff requested, in RAI 4.7.3-1, that the applicant clarify this aspect of the SNSW pond volume program. In its response dated March 11, 2002, the applicant stated that, in the event that a future survey of the topography of the bottom of the SNSW pond indicates a reduction in the volume of water due to the buildup of sediment, remedial actions may include, but not be limited to the following:

- enlargement of the pond by excavation
- raising the required Technical Specification elevation
- dredging of the pond
- modification of the pond to raise the surface elevation

The staff finds these remedial actions acceptable because they provide an effective means of managing the aging effect due to sedimentation.  With the closure of this RAI concern, the staff finds the detection of aging effects acceptable.

[Monitoring and Trending]  The design parameter (volume of water within the SNSW pond) is validated using the SNSW Pond Volume Program.  Conventional methods of surveying and volume calculation are used.  A contour map with a known scale is developed as a result of the survey.  Areas within each contour at different elevations are determined.  Using the contour intervals and the area at each contour interval, volumes are computed for each contour elevation.  The computed surface areas and the volume of water below the specified pond surface elevations at each contour elevation are compared to the areas and volumes in Figure 9-54 in the Catawba UFSAR to ensure that an adequate volume of water is available.

The SNSW Pond Volume Program is performed once every three years, and is documented and retained in sufficient detail to permit adequate confirmation of the results.  The staff finds the monitoring and trending acceptable because the monitoring frequencies will permit an effective management of the aging effects, and because monitoring is performed by utilizing reliable and conventional surveying methods.

[Acceptance Criteria]  The acceptance criteria are contained in the area-volume curve shown in Catawba UFSAR, Figure 9-54.  Calculated areas and volumes are compared to the criteria in Figure 9-54.  The staff finds the acceptance criteria to be adequate and acceptable because the applicant has used conservative and reasonable margins to estimate the volume of water in the SNSW pond.

[Operating Experience]  The LRA states that previous surveys and calculations have verified that the surface area and volume of water in the SNSW pond is sufficient.  The surveys were performed in accordance with plant procedures that implement the requirements of TS 5.4. The staff finds this approach acceptable because proven surveying methods were used to demonstrate that pond volume was sufficient.

*4.7.3.3 FSAR Supplement*

The changes to the Catawba UFSAR related to this TLAA are provided in the FSAR supplement in Appendix A-2 of the LRA.  The staff reviewed the changes documented therein and finds them appropriate and acceptable.

*4.7.3.4 Conclusions*

On the basis of the review described above, the staff concludes that the applicant has demonstrated that the SNSW Pond Volume Program will adequately manage the aging effects associated with the SNSW pond so that there is reasonable assurance that it will continue to perform its intended function in accordance with the CLB for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii).

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# 5. REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

The NRC staff issued its safety evaluation report (SER) with open items related to the renewal of operating licenses for McGuire, Units 1 and 2, and Catawba, Units 1 and 2, on August 14, 2002. On October 8, 2002, the applicant presented its license renewal application, and the staff presented its review findings, to the ACRS Plant License Renewal Subcommittee. The staff reviewed the applicant's responses to SER open and confirmatory items and completed its review of the license renewal application. The staff's evaluation is documented in an SER that was issued by letter dated January 6, 2003.

During the 499th meeting of the ACRS on February 5-7, 2003, the ACRS completed its review of the McGuire and Catawba license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated February 14, 2003. A copy of this letter is provided on the following pages of this SER Chapter.

ACRSR-2019

February 14, 2003

The Honorable Richard A. Meserve
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE MCGUIRE NUCLEAR STATION UNITS 1 AND 2 AND THE CATAWBA NUCLEAR STATION UNITS 1 AND 2

Dear Chairman Meserve:

During the 499th meeting of the Advisory Committee on Reactor Safeguards on February 6–8, 2003, we completed our review of the License Renewal Application (LRA) for the McGuire Nuclear Station Units 1 and 2 (McGuire) and the Catawba Nuclear Station Units 1 and 2 (Catawba), and the related final safety evaluation report (SER) prepared by the NRC staff. Our review included a meeting of our Plant License Renewal Subcommittee on October 8, 2002. During our review, we had the benefit of discussions with representatives of the NRC staff and Duke Energy Corporation (Duke). We also had the benefit of the documents referenced.

**CONCLUSIONS AND RECOMMENDATIONS**

1. The Duke application for renewal of the operating licenses for McGuire Units 1 and 2 and Catawba Units 1 and 2 should be approved.

2. The programs instituted to manage aging-related degradation are appropriate and provide reasonable assurance that McGuire Units 1 and 2 and Catawba Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

**BACKGROUND AND DISCUSSION**

This report fulfills the requirement of 10 CFR 54.25, which states that the ACRS should review and report on all license renewal applications. McGuire Units 1 and 2 and Catawba Units 1 and 2 are 3,411- MWt, four-loop Westinghouse pressurized-water reactors (PWRs) in ice condenser containments. In its application, Duke requested that the NRC renew the operating licenses for all four units beyond their current license terms, which expire on June 12, 2021 (McGuire Unit 1); March 3, 2023 (McGuire Unit 2); December 6, 2024 (Catawba Unit 1); and February 24, 2026 (Catawba Unit 2). At the time of the application, only McGuire Unit 1 met the requirements of 10 CFR 54.17(c), which prohibits an applicant from submitting an application for license renewal earlier than 20 years before the expiration of its current operating license. Duke requested an exemption from this requirement, which the NRC staff granted based on the similarities of the four units and the efficiency of a single application.

The final SER documents the results of the staff's review of information submitted by Duke, including commitments that were necessary to resolve open items identified by the staff in the initial SER. In particular, the staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are subject to aging management; the integrated plant assessment process; the applicant's identification of the possible aging mechanisms associated with passive, long-lived components; and the adequacy of the applicant's aging management programs. The staff also conducted several inspections at Duke's engineering offices and at the McGuire and Catawba sites to verify the adequacy of the methodology described in the application and its implementation.

During our Plant License Renewal Subcommittee meeting on October 8, 2002, the lead NRC license renewal inspector for Region II provided an overview of the NRC's inspection process. This process, which is well-structured and effective, is becoming increasingly important as license renewal applications become less detailed. As a result, as in other recent applications, the review of the McGuire and Catawba LRA required a substantial number of requests for additional information and depended heavily on review of plant drawings at the sites.

On the basis of our review of the final SER, we agree with the staff's conclusion that all open and confirmatory items have been closed appropriately, and there are no issues that preclude renewal of the operating licenses for McGuire Units 1 and 2 and Catawba Units 1 and 2.

The process implemented by the applicant to identify SSCs that are within the scope of license renewal was effective. However, in the initial SER the staff identified a number of SSCs that should have been in the scope of license renewal but were excluded by Duke's interpretation of license renewal requirements. Among those SSCs were fan and damper housings, building sealants, electrical equipment connecting the units to the offsite power source for recovery from station blackout (SBO), and jockey pumps and manual fire suppression equipment in potential fire exposure areas. The inclusion of fan and damper housings, building sealants, and SBO equipment has been disputed in previous license renewal applications.

For fan and damper housings, Duke initially took the position that loss of pressure retention or structural integrity function would be evidenced by functional failure, as is a failure of the active components of dampers and fans. By contrast, the staff views the passive components of these assemblies as being within the scope of license renewal, just like pump casings, which are explicitly called for in 10 CFR 54.21. We agree that the explicit example provided in the rule supports the staff's interpretation. With regard to jockey pumps, the staff determined that these components are relied upon to meet the requirements of 10 CFR 50.48, "Fire Protection." We concur with the staff's determination. Duke agreed to close these open items by bringing all of the identified SSCs into the scope of license renewal.

During our review, we questioned why certain other SSCs were not included within the scope and, in all cases, the applicant provided appropriate justification for exclusion. We conclude that the applicant and the staff have appropriately identified all SSCs that are within the scope of license renewal.

The applicant performed a comprehensive aging management review of SSCs that are within the scope of license renewal. Appendix B to the LRA describes 51 aging management programs for license renewal, which include existing, enhanced, and new programs. In addition, the resolution of staff questions and SER open items has resulted in further commitments, including the implementation of a one-time inspection of the condenser circulating water system expansion joints at Catawba to characterize potential degradation, one-time VT-1 inspection of the pressurizer spray head, one-time inspection of the internal surfaces of the auxiliary feedwater system carbon steel piping components, and an inspection program for non-environmentally qualified neutron flux instrumentation circuits. The SER lists 21 such committed actions to be implemented by the applicant.

The McGuire and Catawba LRA includes a new aging management program, the Alloy 600 Aging Management Review. This program is intended to identify Alloy 600/690, 82/182, and 52/152 locations; to rank susceptibility to primary water stress corrosion cracking (PWSCC); and to verify that nickel-based alloy locations are adequately inspected by the Inservice Inspection Program, the Control Rod Drive Mechanism and other Vessel Head Penetration (VHP) programs, the Reactor Vessel Internals Program, and the Steam Generator Integrity Program. This review will provide general oversight and management of cracking due to PWSCC. We applaud this initiative to provide comprehensive oversight of activities to manage PWSCC. Given the current challenge created by PWSCC, we encourage Duke to implement this program soon, in the current license term, rather than waiting for the end of the initial license terms of the four units.

With regard to reactor vessel penetration nozzle cracking and head wastage issues, Duke has committed to incorporate the future industry resolution of these issues into the VHP Nozzle Program and the Alloy 600 Management Review Program. This provides reasonable assurance that the effects of aging associated with the VHP Nozzle Program and the Alloy 600 Review Program will be adequately managed so that the intended function(s) will be maintained in a manner that is consistent with the current licensing basis throughout the period of extended operation.

Duke is the first utility to seek license renewal for plants that use ice condensers in the containment to absorb thermal energy in the event of a loss-of-coolant-accident or a steamline break. Duke has developed a new program to manage aging degradation of ice baskets and ice condenser components at McGuire and Catawba. We agree with the staff's conclusion that the proposed program is adequate to identify and manage aging effects during the period of extended operation.

Duke identified those components of the McGuire and Catawba plants that are supported by time-limited aging analyses and provided sufficient data to demonstrate that the components have sufficient margin to operate properly for the period of extended operation.

As noted in previous applications, LRAs include a substantial number of activities and commitments that will not be accomplished until near the end of the current license period. Consequently, the NRC staff will need to conduct a substantial amount of inspection activity just before the plants enter the extended period of operation. The staff is aware of this future workload and has issued Inspection Procedure 71003, "Post-Approval Site Inspection for License Renewal," to manage this significant effort. Given the large number of power plants that will approach the license renewal term at approximately the same time, this nationwide inspection effort is likely to impose a major demand for staff resources.

The staff has performed an outstanding review of the Duke application. The applicant and the staff have identified plausible aging effects associated with passive, long-lived components. The applicant has also established adequate programs to manage the effects of aging so that McGuire Units 1 and 2 and Catawba Units 1 and 2 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

Sincerely,

**/RA/**

Mario V. Bonaca
Chairman

References:

1. Letter dated June 13, 2001, from M. S. Tuckman, Duke Energy Corporation, to U. S. Nuclear Regulatory Commission, transmitting Application to Renew the Operating Licenses of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2.
2. U.S. Nuclear Regulatory Commission, NUREG-XXX, "Safety Evaluation Report Related to the License Renewal of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2," January 2003.
3. U.S. Nuclear Regulatory Commission, NRC Inspection Procedure 71003, "Post-Approval Site Inspection for License Renewal," December 9, 2002.

# 6. CONCLUSIONS

The staff performed its review of the McGuire and Catawba license renewal application in accordance with Federal regulations and the NRC's "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," issued July 2001.  The standards for issuance of a renewed license are provided in 10 CFR 54.29.

On the basis of its evaluation of the application as discussed above, the staff has determined that it will be able to conclude that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 will be documented in the plant-specific supplement to the Generic Environmental Impact Statement.  Should the resolution of Subpart A of 10 CFR Part 51 be favorable, the staff will be able to conclude that the requirements of 10 CFR 54.29(b) have been met.

At this time, no matters have been raised under 10 CFR 2.758 that need to be addressed.  The staff reserves judgment regarding the requirements of 10 CFR 54.29(c) until such time that it can determine if matters have been raised under 10 CFR 2.758.

## APPENDIX A
## CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke Energy Corporation (Duke). This appendix also contains other correspondence regarding the NRC staff's review of the McGuire Nuclear Station, Units 1 and 2, (under docket Nos. 50-369 and 50-370), and Catawba Nuclear Station, Units 1 and 2, (under docket Nos. 50-413 and 50-414).

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| May 8, 2001 | In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on May 21, 2001. In this meeting, Duke planned to discuss schedules for planned license renewals for McGuire and Catawba Nuclear Stations. ACN: ML011290008 |
| June 5, 2001 | In a letter (signed by C. Araguas), the NRC issued a notice for a public meeting on June 20, 2001, between the NRC, Duke, Virginia Electric Power Company (VEPCo), and Exelon. In this meeting, the licensees planned to continue discussions from a prior meeting on May 21, 2001, on the review schedules for their planned license renewal application. ACN: ML011560744 |
| June 6, 2001 | In a letter (signed by S. Hoffman), the NRC published a summary of a public meeting that was held on May 21, 2001, between the NRC, Duke, VEPCo, and Exelon regarding the review schedules for their planned license renewal application. ACN: ML011590263 |
| June 7, 2001 | In a letter (signed by R. Prato), the summary of a telecommunication between the NRC, VEPCo, and Duke was published and documented. The telecommunication was held on June 6, 2001. Duke discussed an integrated inspection schedule for the license renewal inspection activities planned for McGuire and Catawba Nuclear Stations. ACN: ML011590499 |
| June 13, 2001 | In a letter (signed by M.S. Tuckman), Duke submitted its form and content of License Renewal Application (LRA) and Appendices for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML011660301 |
| June 13, 2001 | In a letter (signed by M.S. Tuckman), Duke submitted its intent to apply for renewal of the operating licenses of McGuire and Catawba power stations. In its submittal, Duke provided fourteen copies of the application. ACN: ML011660138 |
| June 13, 2001 | In a letter (signed by M.S. Tuckman), Duke submitted two sets of marked flow drawings to aid the NRC in its review of *Application to Renew the Operating Licenses of McGuire Nuclear Station, Units 1 and 2 and Catawba Nuclear Station, Units 1 and 2*. ACN: ML011660168 |

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| June 28, 2001 | In a letter (signed by M.S. Tuckman), Duke submitted its application to renew the operating licenses of McGuire and Catawba power stations. In its submittal, Duke provided one hard copy of the application and 40 copies of the application on CD ROM. ACN: ML011840032 |
| June 28, 2001 | In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on July 12, 2001. In this meeting, Duke planned to provide the NRC staff with a review of the license renewal application for McGuire and Catawba Nuclear Stations, and to clarify the organization of the license renewal application. ACN: ML011800037 |
| July 10, 2001 | In a letter (signed by R. Franovich), the NRC published a summary of a public meeting that was held on June 20, 2001, between the NRC, Duke, VEPCo, and Exelon. This meeting was held to continue discussions from the prior meeting on May 21, 2001, on the review schedules for their planned license renewal applications. ACN: L011930405 |
| July 24, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on July 19, 2001, to clarify technical information provided by Duke in LRA Table 3.2-4. ACN: ML012070063 |
| July 26, 2001 | In a letter (signed by R. Franovich), the NRC published a summary of a public meeting that was held on July 12, 2001, between the NRC and Duke to provide an orientation for the staff on the McGuire and Catawba LRA. ACN: ML012080051 |
| August 31, 2001 | In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on September 19, 2001, between the NRC, the Nuclear Energy Institute (the NEI), Southern Nuclear Oporation Company (SNC), Hatch Nuclear Plant, Units 1 and 2 (HNP), Florida Power and Light Company (FPL), Duke, VEPCo, and Exelon. In this meeting, the licensees planned to discuss the review status of their LRAs. ACN: ML012430275 |
| September 10, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on August 21, 2001, to clarify information provided by Duke on the Boraflex Monitoring Program in LRA Appendix B. ACN: ML012530283 |
| October 3, 2001 | In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 18, 2001, between the NRC and Duke to discuss a scoping methodology audit in support of license renewal application review for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML012770008 |

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| October 10, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on September 12, 2001, to clarify information provided by Duke in its LRA on several waste treatment and disposal systems. ACN: ML012830102 |
| October 15, 2001 | In a letter (signed by R. Franovich), the summary of two telecommunications between the staff and Duke was published and documented. These telecommunications were held on September 18 and 20, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding scoping of structures and components in the fire protection systems. ACN: ML012880370 |
| October 21, 2001 | In a letter (signed by S. Hoffman), the NRC issued a summary of a public meeting that was held on September 19, 2001, between the NRC, the NEI, SNC, FPL, VEPCo, Duke, and Exelon regarding the status of license renewal activities. ACN: ML012840369 |
| November 2, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 3, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding scoping of structures and components in the fire protection systems. ACN: ML013060438 |
| November 14, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 11, 2001, to clarify information provided by Duke in its McGuire and Catawba LRA regarding containment systems. ACN: ML013190029 |
| November 14, 2001 | In a letter (signed by C. Grimes), the NRC provided the NEI, the Union of Concerned Scientists (the UCS), and current license renewal applicants with their proposed staff guidance on station blackout scoping for comments. ACN: ML013180508 |
| November 15, 2001 | In a letter (signed by R. Franovich), the NRC issued a summary of a public exit meeting that was held on October 19, 2001, between the NRC and Duke regarding the scoping methodology audit in support of license renewal application review for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML013190507 |
| November 23, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 11, 2001, to clarify information presented in the LRA pertaining to aging management programs for structures. ACN: ML013310117 |

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| November 23, 2001 | In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with proposed changes to the “Generic Aging Lessons Learned” (GALL) report for comments on the aging management of concrete. ACN: ML013300426 |
| November 23, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 15, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B, Inservice Inspection Plan. ACN: ML013300361 |
| November 30, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 25, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 3.5. ACN: ML013370544 |
| November 30, 2001 | In a letter (signed by R. Prato), the NRC issued a notice for a public meeting on December 12, 2001, between the NRC, VEPCo, Duke, Exelon, and the NEI to discuss license renewal emerging issues. ACN: ML013370001 |
| December 3, 2001 | In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with the staff’s characterization of the license renewal issue pertaining to scoping of seismic II/I piping for comments. ACN: ML013380013 |
| December 11, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 30, 2001, to clarify information presented in the LRA pertaining to aging management programs for mechanical systems and components. ACN: ML013460154 |
| December 11, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 8, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section B.3.12, Fire Protection Program. ACN: ML013460269 |
| December 12, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on October 25, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B. ACN: ML013460417 |

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| December 13, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 5, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Appendix B, on aging management programs for mechanical systems and components. ACN: ML013470364 |
| December 14, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on December 3, 2001, to clarify information presented by Duke on its McGuire and Catawba LRA, Section B.3.6. ACN: ML013520129 |
| December 14, 2001 | In a letter (signed by S. Hoffman), the NRC issued a notice for a public meeting on January 8, 2002, between the NRC, SNC, FPL, VEPCo, Duke, and Exelon to discuss the review status and other activities associated with LRAs. ACN: ML013510294 |
| December 18, 2001 | In a letter (signed by R. Prato), the NRC issued a notice for a public meeting on January 10, 2002, between the NRC, VEPCo, Duke, Exelon, and the NEI to discuss license renewal station blackout issues. ACN: ML013600335 |
| December 27, 2001 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 13, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.5, 3.6, and B.3.19. ACN: ML013650428 |
| January 10, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 20, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 4.6. ACN: ML020110099 |
| January 11, 2002 | In a letter (signed by D. Solorio), the NRC issued a notice for a public meeting on January 15, 2002, during which the NEI and current license renewal applicants planned to follow up on the January 10, 2002, meeting regarding the license renewal station blackout issue. ACN: ML020110589 |
| January 15, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 28, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.3.2 and 2.3.3. ACN: ML020170132 |

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| January 15, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on November 27, 2001, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 2.3.4, 2.3.3.27, 2.3.3.34, and 2.3.3.36. ACN: ML020160418 |
| January 17, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.5, 3.6, and B.3.19 of the McGuire and Catawba LRA. ACN: ML020180061 |
| January 17, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.1 and B.2 of the McGuire and Catawba LRA. ACN: ML020220034 |
| January 17, 2002 | In a letter (signed by P. Kang), the NRC issued a notice for a public meeting on February 14, 2002, between the NRC, the NEI, and current license renewal applicants to discuss revised sections of Chapters II and III of the GALL report on aging management of concrete elements. ACN: ML020220005 |
| January 17, 2002 | In a letter (signed by R. Prato), the NRC issued a summary of a public meeting that was held on December 12, 2001, between the NRC, VEPCo, Duke, Exelon, and the NEI regarding license renewal emerging issues. ACN: ML020300004 |
| January 22, 2002 | In a letter (signed by R. Prato), the NRC published a summary of a public meeting that was held on January 10, 2002, between the NRC, VEPCo, Duke, Exelon, the NEI, and the Nuclear Information and Resource Service regarding the scope of station blackout specific to license renewal. ACN: ML020220351 |
| January 23, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.2 of the McGuire and Catawba LRA. ACN: ML020290102 |
| January 23, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.3.2 of the McGuire and Catawba LRA. ACN: ML020240249 |
| January 24, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.3 of the McGuire and Catawba LRA. ACN: ML020240265 |
| January 28, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 2.3.3 of the McGuire and Catawba LRA. ACN: ML020320212 |

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| January 28, 2002 | In a letter (signed by C. Grimes), the NRC provided the NEI, the UCS, and current license renewal applicants with their proposed guidance on aging management of fire protection systems comments. ACN: ML020320437 |
| January 28, 2002 | In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the revised proposed guidance on station blackout scoping. ACN: ML020300294 |
| January 28, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.2 of the McGuire and Catawba LRA. ACN: ML020320010 |
| January 28, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Appendix B, Aging Management Programs (Mechanical Systems), of the McGuire and Catawba LRA. ACN: ML020310200 |
| January 28, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.3.1, 3.1, 4.2, 4.3, 4.7.1, and Appendix B of the McGuire and Catawba LRA. ACN: ML020310255 |
| January 28, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Sections 2.4, 3.5, 4.6, 4.7.3, and Appendix B of the McGuire and Catawba LRA. ACN: ML020320165 |
| January 30, 2002 | In a letter (signed by R. Franovich), the NRC staff requested additional information (RAI) regarding Section 3.1 and Appendix B, Section B.3.27 of the McGuire and Catawba LRA. ACN: ML020350542 |
| January 31, 2002 | In a letter (signed by P. Kang), the NRC issued a notice for a public meeting on February 14, 2002, between the NRC, the NEI, and current license renewal applicants in order to discuss station blackout issues related to license renewal. This meeting follows discussions initiated in a public meeting held on January 10 and 15, 2002. ACN: ML020320079 |
| February 5, 2002 | In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on January 15, 2002, between the NRC, the NEI, and current license renewal applicants. This meeting was held to continue the discussion that began with the January 10, 2002, meeting on station blackout issues related to license renewal. ACN: ML020380195 |
| February 11, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on January 9, 2002, to clarify information presented by Duke in its McGuire and Catawba LRA, Sections 3.1, B.3.1, B.3.26, B.3.27, B.3.31, and 4.2.1. ACN: ML020420453 |

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| February 13, 2002 | In a letter (signed by D. Solorio), the NRC published a notice for a public meeting on February 25, 2002, between the NRC, the NEI, and current license renewal applicants to discuss implementation details of the license renewal interim staff guidance process. ACN: ML020460082 |
| February 21, 2002 | In a letter (signed by S. Hoffman), the NRC published a summary of a public meeting that was held on January 8, 2002, between the NRC, SNC, FPL, VEPCo, Duke, and Exelon regarding the progress of license renewal application reviews. ACN: ML020560022 |
| March 1, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17 and 23, 2002, regarding the scoping and screening methodology of the McGuire and Catawba LRA. ACN: ML020640428 |
| March 1, 2002 | In a letter (signed by M.S. Tuckman), Duke responded to RAIs on scoping and screening methodology and plant level scoping results. ACN: ML020640428 |
| March 1, 2002 | In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the revised proposed guidance on station blackout scoping. ACN: ML020600100 |
| March 6, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on February 21, 2002, to clarify information presented by Duke in its McGuire and Catawba LRA, Section 2.4.2. ACN: ML020660073 |
| March 7, 2002 | In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on February 14, 2002, between the NRC, the NEI, and current license renewal applicants regarding revised guidance on station blackout scoping. ACN: ML020700212 |
| March 8, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17, 2002, regarding Sections 2.5, 3.6, and Appendix B Section B.3.19 of the McGuire and Catawba LRA. ACN: ML020740025 |
| March 11, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 28, 2002, regarding Sections 2.4, 3.5, 4.6, 4.7.3, and Appendix B of the McGuire and Catawba LRA. ACN: ML020770266 |
| March 13, 2002 | In a letter (signed by S. Hoffman), the NRC published a notice for a public meeting on April 8, 2002, between the NRC, the NEI, and current license renewal applicants to discuss the status of the renewal applications and generic license renewal activities. ACN: ML020720270 |

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| March 15, 2002 | In a letter (signed by K. S. Canady), Duke submitted its response to the NRC staff's RAIs dated January 23 and 28, 2002, regarding aging management review of auxiliary systems and of engineered safety features, including aging management programs for mechanical systems for McGuire and Catawba LRA. ACN: ML020810451 |
| March 15, 2002 | In a letter (signed by C. Grimes), the NRC requested comments from the NEI, the UCS, and current license renewal applicants on the license renewal issue guidance pertaining to 10 CFR 54.4 (a)(2) Scoping. ACN: ML020770026 |
| March 22, 2002 | In a letter (signed by P. Kang), the NRC published a notice for a public meeting on April 10, 2002, between the NRC, the NEI, and current license renewal applicants to discuss revised sections of Chapters II and III of the GALL report on the aging management of concrete elements and other currently emerging issues related to license renewal. ACN: ML020840411 |
| March 22, 2002 | In a letter (signed by P. Kang), the NRC published a notice for a public meeting on April 10, 2002, between the NRC, the NEI, and current license renewal applicants to discuss the staff proposed guidance for aging management of fire protection systems in the GALL report. ACN: ML020840444 |
| April 1, 2002 | In a letter (signed by D. Matthews), the NRC submitted a copy of the revised staff position on scoping station blackout equipment for license renewal and clarified the use of alternate ac power sources. ACN: ML020920464 |
| April 4, 2002 | In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on February 14, 2002, between the NRC, the NEI, and current license renewal applicants regarding revisions to GALL Chapters II and III. ACN: ML020940312 |
| April 5, 2002 | In a letter (signed by C. Grimes), the NRC informed the NEI and current license renewal applicants of its "Staff's Response to Industry's Proposed Changes to GALL Chapters II and III on Aging Management of Concrete Elements." ACN: ML020980194 |
| April 15, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 23 and 28, 2002, and March 1, 8, and 15, 2002, regarding Sections 2.1-2a, 2.1-2b, 2.3.1, 2.3.2, 2.3.3, 3.1, 3.2-1, 3.3-1, 3.3-2, 4.2, 4.3, 4.7.1, B.3.19-1, B.3.19-2, and several sections of Appendix B of the McGuire and Catawba LRA. ACN: ML021120015 |
| April 22, 2002 | In a letter (signed by P. Kang), the NRC published a summary of a public meeting that was held on April 10, 2002, between the NRC, the NEI, and current license renewal applicants regarding staff guidance on license renewal issues. ACN: ML021120407 |

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| April 22, 2002 | In a letter (signed by N. Dudley), the NRC published a summary of a public meeting that was held on April 8, 2002, between the NRC, Omaha Public Power District (OPPD), FPL, VEPCo, Duke, and Exelon regarding the progress of license renewal application reviews. ACN: ML021130114 |
| May 5, 2002 | In a letter (signed by V. McCree), the NRC sent Duke its scoping and screening inspection report. ACN: ML021280003 |
| June 7, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 24, 2002, to clarify information provided by Duke in LRA Section 2.1. ACN: ML021620457 |
| June 7, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 28, 2002, to clarify information provided by Duke in LRA Section 3.5. ACN: ML021700648 |
| June 19, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on June 5, 2002, to clarify information provided by Duke in LRA Section B.3.26. ACN: ML021700621 |
| June 19, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on June 4, 2002, to clarify information provided by Duke in LRA Section 4.3. ACN: ML021750433 |
| June 24, 2002 | In a letter (signed by R. Franovich), the summary of a telecommunication between the staff and Duke was published and documented. The telecommunication was held on May 29, 2002, to clarify information provided by Duke in LRA Sections 3.6 and B.3.19. ACN: ML021620496 |
| June 25, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted Amendment I to the application to renew the facility operating licenses of McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021840126 |
| June 25, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted drawing MCFD-01-01 which is part of Amendment I to the application to renew the facility operating licenses of McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021920158 |
| June 26, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's RAIs dated January 17, 2002, regarding Sections 2.5-1 and 2.5-2 of the McGuire and Catawba LRA. ACN: ML021840103 |

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| June 26, 2002 | In a letter (signed by R. Franovich), the NRC provided Duke potential safety evaluation report open items regarding the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML021770454 |
| July 9, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated June 26, 2002, regarding 29 potential open items and 10 confirmatory items identified during the staff's preparation of its safety evaluation report on the McGuire and Catawba LRA. ACN: ML021960467 |
| August 14, 2002 | In a letter (signed by P. T. Kuo), the NRC issued its safety evaluation report with open items, which documented the staff's initial review of the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML022260949 |
| August 29, 2002 | In a letter (signed by R. Franovich), the NRC provided Duke a revised schedule for the review of the license renewal application for McGuire and Catawba Nuclear Stations, Units 1 and 2. ACN: ML022410304 |
| September 4, 2002 | In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on September 17-19, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open and confirmatory items identified in the SER issued August 14, 2002. ACN: ML022470378 |
| September 6, 2002 | In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML022520227 |
| September 9, 2002 | In a letter (signed by L. Plisco for V. McCree), the NRC sent Duke its aging management review inspection report. ACN: ML022540009 |
| September 12, 2002 | In a letter (signed by R. Franovich), the NRC issued a notice for a public meeting on October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant planned to discuss open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML022560227 |
| September 13, 2002 | In a letter (signed by R. Franovich), the NRC issued a request of revised time-limited aging analyses associated with reactor vessel neutron embrittlement for the staff's review of the license renewal application for McGuire 1. ACN:ML022590100 |

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| October 2, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its interim response to the NRC staff's safety evaluation report with open items issued August 14, 2002, on the McGuire and Catawba LRA. ACN:ML022830191 |
| October 19, 2002 | In a letter (signed by R. Franovich), the NRC issued a revised excerpt from the safety evaluation report with open items and request for additional information to complete the staff's review of the McGuire and Catawba LRA. ACN:ML022940260 |
| October 28, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its second response to the NRC staff's safety evaluation report with open items issued August 14, 2002, on the McGuire and Catawba LRA. ACN:ML023090324 |
| November 5, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated October 19, 2002, regarding a revised excerpt from the safety evaluation report with open items and request for additional information to complete the staff's review of the McGuire and Catawba LRA. ACN:ML023180047 |
| November 7, 2002 | In a letter (signed by R. Franovich), the NRC requested the applicant to address its treatment of fuse holders within the scope of license renewal as long-lived, passive components subject to an aging management review in the McGuire and Catawba LRA. ACN:ML023120413 |
| November 13, 2002 | In a letter (signed by P.T. Kuo), the NRC apprized the applicant of the status of the NRC staff's review of the McGuire and Catawba LRA and safety evaluation report open items that remained unresolved. ACN:ML023170631 |
| November 14, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted its response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN:ML023300321 |
| November 18, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted a supplemental response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN:ML023300288 |
| November 18, 2002 | In a letter (signed by R. Franovich), the NRC issued a summary of the public meetings held September 17-19, 2002, between the NRC and Duke. In this meeting the staff and applicant discussed open and confirmatory items identified in the SER issued August 14, 2002. ACN: ML023220127 |

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| November 21, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted a third response to the NRC staff's letter dated November 13, 2002, regarding safety evaluation report open items that remained unresolved. ACN: ML023180047 |
| November 26, 2002 | In a letter (signed by R. Franovich), the NRC issued a summary of the public meeting held October 1, 2002, between the NRC and Duke. In this meeting the staff and applicant discussed open items pertaining to scoping and screening of fire protection equipment that were identified in the SER issued August 14, 2002. ACN: ML023330429 |
| December 16, 2002 | In a letter (signed by M.S. Tuckman), Duke submitted revised FSAR supplements and a table of license renewal commitments. ACN: ML023540450 |
| January 6, 2003 | In a letter (signed by P. T. Kuo), the NRC issued its safety evaluation report related to the license renewal of McGuire, Units 1 and 2, and Catawba, Units 1 and 2. ACN: ML023640366 |
| February 14, 2003 | In a letter (signed by M. Bonaca), the Advisory Committee on Reactor Safeguards provided its conclusions and recommendations on the renewal of the operating licenses for McGuire, Units 1 and 2, and Catawba, Units 1 and 2. ACN: ML030450549 |

## APPENDIX B
## REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for McGuire 1 and 2, Docket Numbers 50-369 and 50-370, and Catawba 1 and 2, Docket Numbers 50-413 and 50-414.


**American Concrete Institute (ACI)**

ACI 349.3, *Evaluation of Existing Nuclear Safety-Related Concrete Structures.*

ACI 224.1, *Causes, Evaluation, and Repairs of Cracks in Concrete Structures.*

ACI 201, *Guide for Making a Condition Survey of Concrete in Service.*

**American National Standards Institute (ANSI)**

ANSI B30.2.0, *Overhead and Gantry Cranes, Section 2-2, Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks, and Slings*, American National Standard.

ANSI B30.16, *Overhead Hoists (Underhung)*, American National Standard.

**American Society of Mechanical Engineers (ASME)**

ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, *Class 1 Components*.

ASME Boiler and Pressure Vessel Code, Section III, Subsection NG, *Core Support Structures*.

ASME Boiler and Pressure Vessel Code, Section III, *Class 2 and 3 Piping Failures*.

ASME Boiler and Pressure Vessel Code, Section III, Subsection ND, *Class 3 Rules for Construction of Nuclear Power Plant Components*.

ASME Boiler and Pressure Vessel Code, Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components,* 1992 Edition.

ASME Boiler and Pressure Vessel Code, Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, 1989 Edition.

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, *Requirements for Class 1 Components of Light-Water Cooled Power Plants*.

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWC, *Requirements for Class 2 Components of Light-Water Cooled Power Plants*.

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants.*

ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWF, *Requirements for Class 1, 2, 3, and MC Component Supports of Light Water Cooled Plants*.

ASME Boiler and Pressure Vessel Code, Section XI, Appendix G, *Fracture Toughness Criteria for Protection Against Failure*.

ASME Boiler and Pressure Vessel Code, Code Case N-481, *Alternative Examination Requirements for Cast Austenitic Pump Casings, Section XI, Division 1*.

**Department of Energy - National Laboratories**

Sandia Contractor Report SAND 96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations*, prepared by Ogden Environmental and Energy Services, Inc., September 1996.

SAND 93-7069, *Aging Management Guideline for Commercial Nuclear Power Plants - Motor Control Centers*, February 1994.

SAND 93-7027, *Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Switchgear*, July 1993.

**Duke Energy Corporation**

***Correspondence***

Letter from W. R. McCollum (Duke) to the U.S. Nuclear Regulatory Commission Document Control Desk, ". . . Response to NRC Bulletin 2001-01: Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 28, 2001.

***Reports***

*McGuire Nuclear Station Updated Final Safety Analysis Report*, issued April 13, 2001.

*Catawba Nuclear Station Updated Final Safety Analysis Report*, issued October 8, 2000.

***Submittal***

*Application to Renew the Operating Licenses of McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2,* dated June 13, 2001.

***Technical Document Specifications***

DPS-1274.00-00-001, Revision 2, *License Renewal Technical Information Development Guide*, September 3, 2000.

CNS-1274.00-00-001, Revision 2, *License Renewal Technical Information Development Guide*, September 3, 2000.

MCS-1274.00-00-001, Revision 2, *License Renewal Technical Information Development Guide*, September 3, 2000.

CNS-1274.00-00-0002, Revision 5, *Systems and Structures Scoping for License Renewal*, Catawba Nuclear Station, Units 1 & 2, September 12, 2001.

MCS-1274.00-00-0002, Revision 5, *Systems and Structures Scoping for License Renewal*, McGuire Nuclear Station, Units 1 & 2, September 12, 2001.

CNS-1274.00-00-0003, Revision 1, *Mechanical component Screening and Aging Management Review Methodology for License Renewal*, Catawba Nuclear Station, Units 1 & 2, June 1, 2000.

MCS-1274.00-00-0003, Revision 1, *Mechanical component Screening and Aging Management Review Methodology for License Renewal*, McGuire Nuclear Station, Units 1 & 2, June 1, 2000.

CNS-1274-00-00-0006, Revision 1, *Electrical Component Integrated Plant Assessment and Evaluation of Time-Limited Aging Analysis for License Renewal*, Catawba Nuclear Station, Units 1 & 2, June 12, 2001.

MCS-1274-00-00-0006, Revision 1, *Electrical Component Integrated Plant Assessment and Evaluation of Time-Limited Aging Analysis for License Renewal*, McGuire Nuclear Station, Units 1 & 2, June 12, 2001.

CNS-1274.00-00-0007, Revision 1, *Structures and Structural Components Screening and Aging Management Review for License Renewal*, Catawba Nuclear Station, Units 1 & 2, June 8, 2001.

MCS-1274.00-00-0007, Revision 1, *Structures and Structural Components Screening and Aging Management Review for License Renewal*, McGuire Nuclear Station, Units 1 & 2, June 8, 2001.

CNS-1274.CF-00-0001, Revision 2, *Feedwater System Component Screening and Aging Management Review for License Renewal*, Catawba Nuclear Station, Units 1 & 2, April 23, 2001.

CNS-1274.NI-00-0001, Revision 2, *Safety Injection System Component Screening and Aging Management Review for License Renewal*, Catawba Nuclear Station, Units 1 & 2, April 19, 2001.

**Electric Power Research Institute (EPRI) and Materials Reliability Program (MRP)**

EPRI Report TR-105714, Volume 1, Revision 4, and Volume 2, Revision 4, *PWR Primary Water Chemistry Guidelines*, January 1999.

EPRI Report TR-102134, Revision 5, *PWR Secondary Water Chemistry Guidelines*, December 1999.

EPRI Report TR 107621, Revision 1, *Steam Generator Examination Guidelines*, September 1997.

EPRI Report NSAC-202L, Revision 2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, December 1998.

EPRI Report TR-103834-P1-2, *Effects of Moisture on the Life of Power Plant Cables, Part 1: Medium-Voltage Cables, Part 2: Low-Voltage Cables*, prepared by Ogden Environmental and Energy Services Company, Final Report, August 1994.

EPRI Report TR-10003057, *License Renewal Electrical Handbook*, November 2001.

EPRI Report TR-107396, *Closed Cooling Water Chemistry Guidelines*, October 1997.

EPRI Report TR-109619, *Guideline for the Management of Adverse Localized Equipment Environment,* June 1999.

EPRI Report TR-1003083, *Materials Reliability Program Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47)*, October 2001.

MRP Topical Report TP-1001491, Part 2, *PWR Materials Reliability Program Interim Alloy 600 Safety Assessment for U.S. Power Plants (MRP-44)*, May 2001.

**Miscellaneous**

Shah, V.N. and P.E. MacDonald, editors, *Aging and Life Extension of Major Light Water Reactor Components*, Elsevier Science Publishers, 1993.

**Nuclear Energy Institute (NEI)**

NEI 95-10, Revision 2, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule*, August 2000.

NEI 95-10, Revision 3, *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule*, March 2001.

NEI 97-06, *Steam Generator Program Guidelines*, 1997.

NEI 96-03, *Industry Guideline for Monitoring Structures*.

**Nuclear Management and Resources Council (NUMARC)**

NUMARC Report Number 87-00, *Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors*, November 1987.

NUMARC Report Number 90-01, *Pressurized Water Reactor Containment Structures License Renewal Industry Report*, Revision 1, September 1991.

NUMARC Report Number 90-06, *Class I Structures License Renewal Industry Report*, Revision 1, December 1991.

**US Nuclear Regulatory Commission (NRC)**

***Bulletins (BL)***

BL 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants,* June 2, 1982.

BL 88-09, *Thimble Tube Thinning in Westinghouse Reactors*, July 26, 1988.

BL 88-11, *Pressurizer Surge Line Thermal Stratification*, December 20, 1988.

BL 2001-001, *Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles*, August 3, 2001.

BL 2002-01, *Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity*, March 18, 2002.

BL 2002-02, *Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs*, August 9, 2002.

***Code of Federal Regulations (10 CFR)***

10 CFR 50.36, *Technical Specifications*, U.S. Nuclear Regulatory Commission.

10 CFR 50.48, *Fire Protection*, U.S. Nuclear Regulatory Commission.

10 CFR 50.49, *Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants*, U.S. Nuclear Regulatory Commission.

10 CFR 50.55a, *Codes and Standards*, U.S. Nuclear Regulatory Commission.

10 CFR 50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events*, U.S. Nuclear Regulatory Commission.

10 CFR 50.62, *Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants*, U.S. Nuclear Regulatory Commission.

10 CFR 50.63, *Loss of All Alternating Current Power*, U.S. Nuclear Regulatory Commission.

10 CFR 50.90, *Application for Amendment of License or Construction Permit*, U.S. Nuclear Regulatory Commission.

10 CFR 50 *Domestic Licensing of Production and Utilization Facilities,* U.S. Nuclear Regulatory Commission.

10 CFR Part 50, Appendix G, *Fracture Toughness Requirements*, U.S. Nuclear Regulatory Commission.

10 CFR Part 50, Appendix H, *Reactor Vessel Material Surveillance Program Requirements*, U.S. Nuclear Regulatory Commission.

10 CFR Part 51, *Environmental Protection Regulation for Domestic Licensing and Related Regulatory Functions*, U.S. Nuclear Regulatory Commission.

10 CFR Part 54, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants*, U.S. Nuclear Regulatory Commission.

10 CFR Part 100, *Reactor Site Criteria*, U.S. Nuclear Regulatory Commission.

10 CFR Part 100, Appendix A, *Seismic and Geological Siting Criteria for Nuclear Power Plants*, U.S. Nuclear Regulatory Commission.

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***Correspondence***

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## APPENDIX C
## PRINCIPAL CONTRIBUTORS

| NAME | RESPONSIBILITY |
|---|---|
| C. Araguas | Technical Support |
| R. Architzel | Plant Systems |
| H. Ashar | Structural Engineering |
| G. Bagchi | Technical Support |
| S. Baily | Technical Support |
| A. Baltazar | Technical Support |
| N. Barnett | Administrative Support |
| E. Barnhill | Administrative Support |
| R. Barrett | Management Supervision |
| W. Bateman | Management Supervision |
| L. Bell | Administrative Support |
| S. Black | Management Supervision |
| B. Boger | Management Supervision |
| W. Burton | Technical Support |
| J. Calvo | Management Supervision |
| R. Caruso | Management Supervision |
| C. Casto | Management Supervision |
| P.Y. Chen | Mechanical Engineering |
| S. Chey | Administrative Support |
| S. Coffin | Management Supervision |
| B. Crowley | Region II Inspector |
| D. Cullison | Plant Systems |
| J. Cushing | Technical Support |
| J. Davis | Materials Engineering |
| W. Dean | Management Supervision |
| C. Dorsey | Administrative Support |
| N. Dudley | Technical Support |
| T. Eaton | Plant Systems |
| B. Elliot | Reactor Systems |
| R. Elliott | Plant Systems |
| J. Fair | Mechanical Engineering |
| R. Franovich | Project Manager |
| Z. Fu | Technical Support |
| G. Galletti | Technical Support |
| A. Gill | Electrical Engineering |
| G. Georgiev | Structural Engineering |
| F. Gillespie | Management Supervision |
| J. Golla | Plant Systems |
| C. Grimes | Management Supervision |
| J. Guo | Plant Systems |

| | |
|---|---|
| J. Hannon | Management Supervision |
| M. Hartzman | Technical Support |
| G. Hatchett | Plant Systems |
| A. Henry | Technical Support |
| S. Hoffman | Technical Support |
| G. Holahan | Management Supervision |
| C. Holden | Management Supervision |
| C. Julian | Region II Inspector |
| P. Kang | Technical Support |
| M. Khanna | Materials Engineering |
| V. Klco | Technical Support |
| P. Kleene | Technical Editing |
| J. Knox | Electrical Engineering |
| S. Koenick | Technical Support |
| P.T. Kuo | Management Supervision |
| C. Lauron | Structural Engineering |
| J. Lazevnick | Electrical Engineering |
| A. Lee | Management Supervision |
| S. Lee | Technical Support |
| J. Lehning | Technical Support |
| C. Li | Plant Systems |
| Y. Li | Technical Support |
| L. Lund | Management Supervision |
| K. Manoly | Management Supervision |
| D. Matthews | Management Supervision |
| J. Medoff | Materials Engineering |
| L. Moore | Region II Inspector |
| C. Munson | Structural Engineering |
| J. Nakoski | Management Supervision |
| D. Nguyen | Electrical Engineering |
| D. Oudinot | Plant Systems |
| K. Parczewski | Chemical Engineering |
| J. Peralta | Technical Support |
| R. Prato | Backup Project Manager |
| T. Quay | Management Supervision |
| K. Rico | Backup Project Manager |
| J. Rajan | Mechanical Engineering |
| M. Razzaque | Reactor Systems |
| B. Rogers | Technical Support |
| S. Saba | Electrical Engineering |
| P. Shemanski | Electrical Engineering |
| S. Sheng | Mechanical Engineering |
| A. Smith | Materials Engineering |
| D. Solorio | Technical Support |
| J. Strosnider | Management Supervision |
| O. Tabatabai | Backup Project Manager |
| D. Thatcher | Management Supervision |
| B. Thomas | Management Supervision |
| J. Tsao | Mechanical Engineering |

| | |
|---|---|
| P.K. VanDoorn | Region II Inspector |
| H. Walker | Technical Support |
| H. Wang | Technical Support |
| S. Weerakkody | Management Supervision |
| J. Wermiel | Management Supervision |
| A. Williamson | Technical Support |

## CONTRACTORS

| <u>Contractor</u> | <u>Technical Area</u> |
|---|---|
| Brookhaven National Laboratory | Aging Management Reviews |
| Pacific Northwest National Laboratory | Aging Management Reviews |

# APPENDIX D
# LIST OF APPLICANT COMMITMENTS

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 1. | (a) Complete the Alloy 600 Aging Management review.<br><br>(b) Submit the results of the review for the pressurizer surge and spray nozzle thermal sleeve attachment welds.<br><br>(c) The summary aging management program descriptions contained in this UFSAR will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communications that results from the Davis-Besse event in March 2002.<br><br>(d) The results of this review will be incorporated into the unit specific inservice inspection (ISI) plan for the ISI intervals during the period of extended operation. | 18.2.1 | (a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.<br><br>(b) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.<br><br>(c) As necessary<br><br>(d) Prior to the respective ISI interval | Application B.3.1; Duke letters dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) and 11/21/2002 (Item 3) |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 2. | Complete the Borated Water Systems Stainless Steel Inspection. | 18.2.2 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.4 |
| 3. | (a) Implement the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program.<br><br>(b) Update UFSAR summary description of this program to reflect any new or revised commitments made by Duke in response to the staff generic communications that result from the Davis-Besse event in March 2002. | 18.2.6 | (a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.<br><br>(b) As necessary | Application B.3.9; Duke letter dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 4. | Implement enhancements to the Fire Protection Program to provide surveillances for sprinkler branch lines, main fire pump strainer, jockey pump strainer, tank and connected piping, and turbine building manual hose stations. | 18.2.8 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.12; Duke letters dated 03/15/2002 (Commitment #8), 10/28/2002 (response to Open Items 2.3.3.19-2 & 2.3.3.19-5), and 11/18/2002 response to (Open Item 2.3.3.19-4) |
| 5. | Complete the Galvanic Susceptibility Inspection. | 18.2.12 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.16; Duke letter dated 03/15/2002 (Commitment #10) |
| 6. | Implement enhancements to the Heat Exchanger Preventive Maintenance Activities to provide surveillances for pump motor air handling units and pump oil coolers. | 18.2.13 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.17; Duke letter dated 10/28/2002 (Duke identified Mechanical Item 09/18/2002) |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 7. | Implement the Inaccessible Non-EQ Medium Voltage Cables Aging Management Program. | 18.2.15 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.19; Duke letters dated 10/02/2002 (Confirmatory Item 3.6.2-1) and 11/05/2002 (Attachment 1) |
| 8. | Implement enhancements to the Inservice Inspection Plan to provide surveillances for the Unit 1 cold leg elbow and small bore piping. | 18.2.16 | Evaluation of the Unit 1 cold leg elbow will be completed following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.<br><br>Small bore piping examinations will be performed during each inservice inspection interval during the period of extended operation following issuance of the renewed operating licenses for McGuire. | Application B.3.20; Duke letters dated 04/15/2002 (Commitment #1) and 11/14/2002 (response to New Open Item 3.0.3.10.2-1) |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 9. | Implement enhancements to the Inspection Program for Civil Engineering Structures and Components to provide surveillances for exposed external surfaces of mechanical components. | 18.2.17 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.21; Duke letter dated 10/02/2002 (response to Open Item 3.0.3.11.3-1) |
| 10. | Complete the Liquid Waste System Inspection. | 18.2.18 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.22 |
| 11. | Complete the future modification to the Thermal Fatigue Management Program for environmentally assisted fatigue. | 5.2.1 | Prior to the end of the 40$^{th}$ year of each unit's operation. | Application 4.3; Duke letter dated 10/02/2002 (response to Open Item 4.3-4) |
| 12. | Implement the Non-EQ Insulated Cables and Connections Aging Management Program. | 18.2.19 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.23; Duke letter dated 10/02/2002 (response to SER Confirmatory Item 3.6.1.1) |

## McGuire Nuclear Station
## List of Committed Actions to be Implemented for License Renewal

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 13. | (a) Complete the Pressurizer Spray Head Examination on McGuire Unit 1.<br><br>(b) If necessary, complete the Pressurizer Spray Head Examination on Unit 2. | 18.2.20 | (a) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021.<br><br>(b) Following issuance of the renewed operating licenses for McGuire Nuclear Station and by March 3, 2023. | Duke letters dated 04/15/2002 (response to RAI 2.3.2.7-1) and 10/28/2002 (response to Open Item 3.1.2.2.2-1) |
| 14. | (a) Implement the Reactor Vessel Internals Inspection.<br><br>(b) For items comprised of plates, forgings, and welds critical crack size will be determined by analysis and submitted for review and approval to the NRC.<br><br>(c) For items fabricated from CASS, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed and submitted for review and approval to the NRC. | 18.2.23 | (a) McGuire Unit 1 will be inspected in the fifth inservice inspection interval; McGuire Unit 2 will be inspected early in the sixth inservice inspection interval.<br><br>(b) Prior to the respective inspection.<br><br>(c) Prior to the respective inspection. | Application B.3.27; Duke letter dated 10/28/2002 (response to New Open Items 3.1.4-1(a), (b), and (c)) |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 15. | Complete the Selective Leaching Inspection. | 18.2.24 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.28 |
| 16. | Complete the Sump Pump Systems Inspection. | 18.2.26 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.32 |
| 17. | Complete the Treated Water Systems Stainless Steel Inspection. | 18.2.27 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.34 |
| 18. | Complete the Ventilation Area Pressure Boundary Sealants Inspection. | 18.2.29 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Duke letters dated 10/28/2002 (response to Open Item 2.3-3) and 11/14/2002 (response to Open Item 2.3-3) |
| 19. | Complete the Waste Gas System Inspection. | 18.2.30 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Application B.3.36 |

**McGuire Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 20. | Complete the visual inspections of the interior surfaces of Auxiliary Feedwater System and Main Feedwater System components. | 18.3.3 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Duke letter dated 10/28/2002 (response to New Open Item 3.4.1.2.2-1) |
| 21. | Implement the final version of the fuse holder interim staff guidance as provided to Duke by an NRC letter. | 18.3.4 | Following issuance of the renewed operating licenses for McGuire Nuclear Station and by June 12, 2021. | Duke letter dated 11/18/2002 (response to Item #1) |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 1. | (a) Complete the Alloy 600 Aging Management review.<br><br>(b) Submit the results of the review for the pressurizer surge and spray nozzle thermal sleeve attachment welds.<br><br>(c) The summary aging management program descriptions contained in this UFSAR will be updated as necessary to reflect any new or revised commitments made by Duke in response to the staff generic communications that results from the Davis-Besse event in March 2002.<br><br>(d) The results of this review will be incorporated into the unit specific inservice inspection (ISI) plan for the ISI intervals during the period of extended operation. | 18.2.1 | (a) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.<br><br>(b) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.<br><br>(c) As necessary<br><br>(d) Prior to the respective ISI interval | Application B.3.1; Duke letters dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) and 11/21/2002 (Item 3) |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 2. | Complete the Borated Water Systems Stainless Steel Inspection. | 18.2.2 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.4 |
| 3. | (a) Implement the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program.<br><br>(b) Update UFSAR summary description of this program to reflect any new or revised commitments made by Duke in response to the staff generic communications that result from the Davis-Besse event in March 2002. | 18.2.6 | (a) Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024.<br><br>(b) As necessary | Application B.3.9; Duke letter dated 10/28/2002 (response to New Open Item 3.1.3.2.2-2) |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 4. | Implement enhancements to the Fire Protection Program to provide surveillances for sprinkler branch lines, main fire pump strainer, jockey pump strainer, tank and connected piping, and turbine building manual hose stations. | 18.2.8 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.12; Duke letters dated 03/15/2002 (Commitment #9), 10/28/2002 (response to Open Items 2.3.3.19-2 & 2.3.3.19-5), and 11/18/2002 response to (Open Item 2.3.3.19-4) |
| 5. | Complete the Galvanic Susceptibility Inspection. | 18.2.11 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.16; Duke letter dated 03/15/2002 (Commitment #10) |
| 6. | Implement the Inaccessible Non-EQ Medium Voltage Cables Aging Management Program. | 18.2.14 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.19; Duke letters dated 10/02/2002 (Confirmatory Item 3.6.2-1) and 11/05/2002 (Attachment 1) |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 7. | Implement enhancements to the Inservice Inspection Plan to provide surveillances for small bore piping. | 18.2.15 | During each inservice inspection interval during the period of extended operation following issuance of the renewed operating licenses for Catawba. | Application B.3.20; Duke letters dated 04/15/2002 (Commitment #1) and 11/14/2002 (response to New Open Item 3.0.3.10.2-1) |
| 8. | Implement enhancements to the Inspection Program for Civil Engineering Structures and Components to provide surveillances for exposed external surfaces of mechanical components. | 18.2.16 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.21; Duke letter dated 10/02/2002 (response to Open Item 3.0.3.11.3-1) |
| 9. | Complete the Liquid Waste System Inspection. | 18.2.17 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.22 |
| 10. | Complete the future modification to the Thermal Fatigue Management Program for environmentally assisted fatigue. | 3.9.1 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application 4.3; Duke letter dated 10/02/2002 (response to Open Item 4.3-4) |

## Catawba Nuclear Station
## List of Committed Actions to be Implemented for License Renewal

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 11. | Implement the Non-EQ Insulated Cables and Connections Aging Management Program. | 18.2.18 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.23; Duke letter dated 10/02/2002 (response to SER Confirmatory Item 3.6.1.1) |
| 12. | If necessary following the results of the McGuire Unit 1 examination, complete the Pressurizer Spray Head Examination. | 18.2.19 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024 for Catawba Unit 1 and February 24, 2026 for Catawba Unit 2. | Duke letters dated 04/15/2002 (response to RAI 2.3.2.7-1) and 10/28/2002 (response to Open Item 3.1.2.2.2-1) |
| 13. | Complete the Condenser Circulating Water Pump Expansion Joint Inspection. | 18.2.20.2 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Duke letter dated 11/14/2002 (response to New Open Item 3.3.6.2.1-1) |
| 14. | Implement the Reactor Vessel Internals Inspection. | 18.2.22 | The decision to perform inspections on Catawba Unit 1 and Catawba Unit 2 will depend on an evaluation of the internals inspections performed on McGuire Units 1 and 2. | Application B.3.27; Duke letter dated 10/28/2002 (response to New Open Items 3.1.4-1(a), (b), and (c)) |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 15. | Complete the Selective Leaching Inspection. | 18.2.23 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.28 |
| 16. | Complete the Sump Pump Systems Inspection. | 18.2.25 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.32 |
| 17. | Complete the Treated Water Systems Stainless Steel Inspection. | 18.2.26 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.34 |
| 18. | Complete the Ventilation Area Pressure Boundary Sealants Inspection. | 18.2.28 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Duke letters dated 10/28/2002 (response to Open Item 2.3-3) and 11/14/2002 (response to Open Item 2.3-3) |
| 19. | Complete the Waste Gas System Inspection. | 18.2.29 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Application B.3.36 |

**Catawba Nuclear Station**
**List of Committed Actions to be Implemented for License Renewal**

| Item | Commitment | UFSAR Section | Implementation Schedule | Source |
|---|---|---|---|---|
| 20. | Complete the visual inspections of the interior surfaces of Auxiliary Feedwater System and Main Feedwater System components. | 18.3.3 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Duke letter dated 10/28/2002 (response to New Open Item 3.4.1.2.2-1) |
| 21. | Implement the final version of the fuse holder interim staff guidance as provided to Duke by an NRC letter. | 18.3.4 | Following issuance of the renewed operating licenses for Catawba Nuclear Station and by December 6, 2024. | Duke letter dated 11/18/2002 (response to Item #1) |