Duke Power
A Duke Energy Company

M. S. Tuckman
Executive Vice President
Nuclear Generation

Duke Power
526 South Church St. EC07H
Charlotte, NC 28202
P. O. Box 1006 EC07H
Charlotte, NC 28201-1006
(704) 382-2200 OFFICE
(704) 382-4360 FAX

April 15, 2002

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Subject: Response to Requests for Additional Information in Support of the Staff Review of the Application to Renew the Facility Operating Licenses of McGuire Nuclear Station, Units 1 & 2 and Catawba Nuclear Station, Units 1 & 2

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

Dear Sir:

By letter dated June 13, 2001, Duke Energy Corporation (Duke) submitted an Application to Renew the Facility Operating Licenses of McGuire Nuclear Station and Catawba Nuclear Station (Application). The staff is reviewing the information provided in the Application and has identified areas where additional information is needed to complete its review.

In letters dated January 28 and 30, 2002, the staff requested additional information concerning Sections 2.3.1, 3.1, 4.2, 4.3, 4.7.1, and several sections of Appendix B of the Application. These sections contain information related to the Reactor Coolant System portion of the license renewal review. Attachment 1 provides the Duke response to these two letters. Some of these responses contain commitments. The commitments are restated in Attachment 5 to facilitate tracking and management.

In a letter dated January 23, 2002, the staff requested additional information concerning Section 2.3.2 of the Application. This section contains information related to the system scoping and screening results for engineered safety features. Attachment 2 provides the Duke response to this letter. Some of these responses contain commitments. The commitments are restated in Attachment 5 to facilitate tracking and management.

In a letter dated January 28, 2002, the staff requested additional information concerning Section 2.3.3 of the Application. This section contains information related to the system scoping and screening results for auxiliary systems. Attachment 3 provides the Duke response to this letter. None of these responses contain commitments.

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Duke letters dated March 1, 8, and 15, 2002 submitted responses to many staff requests for additional information (RAI). These letters also deferred the responses to RAIs 2.1.2a, 2.1.2b, 3.2-1, 3.3-1, 3.3-2, B.3.19-1 and B.3.19-2. Attachment 4 provides the Duke responses to these RAIs. Some of these responses contain commitments. The commitments are restated in Attachment 5 to facilitate tracking and management.

If there are any questions, please contact Bob Gill at (704) 382-3339.

Very truly yours,

M. S. Tuckman

M. S. Tuckman

Attachments

Affidavit

M. S. Tuckman, being duly sworn, states that he is Executive Vice President, Nuclear Generation Department, Duke Energy Corporation; that he is authorized on the part of said Corporation to sign and file with the U. S. Nuclear Regulatory Commission the attached responses to staff requests for additional information relative to its review of the Application to Renew the Facility Operating Licenses of McGuire Nuclear Station and Catawba Nuclear Station, Docket Nos. 50-369, 50-370, 50-413 and 50-414 dated June 13, 2001, and that all the statements and matters set forth herein are true and correct to the best of his knowledge and belief. To the extent that these statements are not based on his personal knowledge, they are based on information provided by Duke employees and/or consultants. Such information has been reviewed in accordance with Duke Energy Corporation practice and is believed to be reliable.

M. S. Tuckman

M. S. Tuckman, Executive Vice President
Duke Energy Corporation

Subscribed and sworn to before me this 15TH day of April 2002.

Mary P. Nelms
Notary Public

My Commission Expires:
JAN 22, 2006

xc: (w/ Attachment)

L. A. Reyes
Regional Administrator, Region II
U. S. Nuclear Regulatory Commission
Atlanta Federal Center
61 Forsyth Street, SW, Suite 23T85
Atlanta, GA 30303

D. B. Matthews
Director, Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

Senior NRC Resident Inspector
McGuire Nuclear Station

Senior NRC Resident Inspector
Catawba Nuclear Station

C. P. Patel
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

P. T. Kuo
Program Director, License Renewal and Environmental Impacts
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

R. L. Franovich
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

R. E. Martin
Senior Project Manager
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555

xc: (w/ Attachment)

Henry J. Porter
Assistant Director, Division of Waste Management
Bureau of Land & Waste Management
S.C. Department of Health and Environmental Control
2600 Bull St.
Columbia, SC 29201

R. M. Fry
Director, Division of Radiation Protection
North Carolina Department of Environment, Health, and Natural Resources
3825 Barrett Drive
Raleigh, NC 27609

North Carolina Municipal Power Agency Number 1
1427 Meadowwood Boulevard
P.O. Box 29513
Raleigh, NC 27626

North Carolina Electric Membership Corporation
P.O. Box 27306
Raleigh, NC 27611

Piedmont Municipal Power Agency
121 Village Drive
Greer, SC 29651

Saluda River Electric Cooperative, Inc.
P. O. Box 929
Laurens, SC 29360

Attachment 1
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letters dated January 28, 30, 2002

2.1 System Scoping and Screening Results: Reactor Coolant System

Note: During the preparation of the responses to these RAIs, Duke identified an error in Table 3.1-1 (page 3.1-21, row 1). The note "(CNS – 2 only)" should not have been in this entry. The "Primary Head/Cladding" is applicable to all four units of McGuire and Catawba.

Please also note Duke response to RAI 2.3.2.7-1 (contained in Attachment 2 of this letter) determined that the pressurizer spray head is subject to aging management review.

RAI 2.3.1-1

Borated water leakage through the pressure boundary in pressurized water reactors (PWRs), and resulting borated water induced wastage of carbon steel 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 Boric Acid Wastage Surveillance Program, then it may not require additional aging management. It appears that the subject components were not discussed in the LRA, and therefore, the staff requests the applicant to verify whether the components are within the surveillance program; and if not, to provide an explanation.

Response to RAI 2.3.1-1

The reactor vessel head lifting lugs are considered to be a part of the exterior surfaces of Reactor Coolant System pressure boundary components which are listed in Table 3.1-1 (page 3.1-5, row 1) of the Application. The aging effect of the reactor vessel head lifting lugs is managed by the *Fluid Leak Management Program* which is described in Appendix B.3.15 of the Application. 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.

RAI 2.3.1-2

Some Westinghouse pressurizers are designed with seismic lugs, and valve support bracket lugs. The staff requests the applicant to verify whether such components exist in McGuire and Catawba plants; and if they do, then to explain why the subject components do not require an aging management review (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.

Response to RAI 2.3.1-2

The pressurizer seismic lugs are integral attachments to the pressurizer and are included in Table 3.1-1 as "Reactor Vessel and Pressurizer Integral Attachments" (page 3.1-6, row 2) of the Application. 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. Because the valve support brackets do not perform an intended function, they are not subject to aging management review.

RAI 2.3.1-3

Section 3.9.1.3, page 3.9-4 of McGuire Updated Final Safety Analysis Report (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. Please confirm whether the subject component was identified to be within scope requiring aging management for McGuire. If not, explain why. If the UFSAR is incorrect, please indicate if a change to the UFSAR will be made to correct the information.

Response to RAI 2.3.1-3

Duke's investigation in preparing the response to RAI 2.3.1-3 has identified that the summary analysis provided in UFSAR Section 3.9.1.3 of the McGuire UFSAR is a generic analysis that has been provided by Westinghouse the McGuire NSSS 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 with Westinghouse confirms that the McGuire reactor vessel internals do not have a diffuser plate.

A corrective action report has been entered into the corrective action program to clarify McGuire UFSAR Section 3.9.1.3.

RAI 2.3.1-4
Table 3.1-1 of the LRA identifies components for the steam generators 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 UFSAR, the staff's view is that these components perform the intended function of providing structural and/or functional support for in-scope equipment, namely the steam generator tubes; and therefore, should be within the scope of license renewal requiring an AMR. If the applicant believes that the intended function of the above components to provide structural and/or functional support for the steam generator tubes is not within the scope of license renewal in accordance with 10 CFR 54.4(a)(2), then the staff requests the applicant to affirm 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.

Response to RAI 2.3.1-4
Upon further review, Duke has concluded 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 Units 1 and 2 and Catawba Unit 1). For Catawba Unit 2 items such as anti-vibration bars, stay rods, tube bundle wrapper, and tube support plates are included. The items for all four units are included as "Tube Supports" and the aging management review results are presented below. 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
Steam Generator					
Tube Supports	Support	Alloy Steel Stainless Steel Carbon Steel	Treated Water	Cracking Loss of Material	Chemistry Control Program Steam Generator Surveillance Program

RAI 2.3.1-5

Catawba drawing CN-1553-1.0, "Flow Diagram of Reactor Coolant System," indicates that piping and components downstream of valve 1NC299 is Duke Class F and is within the scope of the LRA. Catawba drawing CN-2553-1.0, "Flow Diagram of Reactor Coolant System," indicates that piping and components downstream of valve 2NC299 is Duke Class F but is not within the scope of the LRA. Explain why the Unit 2 Duke Class F piping and components of the reactor coolant system are not within the scope of license renewal.

Response to RAI 2.3.1-5

The Class F piping on drawing CN-2553-1.0 downstream of 2NC299 is within the scope of license renewal. While the piping is within the license renewal boundary defined by license renewal flags, highlighting was inadvertently omitted from that segment of piping. Piping and valve components in this segment of piping are contained in Table 3.3-41 (page 3.3-239, rows 2, 3, 4, 5; page 3.3-240, rows 2, 3, 4, 5) of the Application.

RAI 2.3.1-6

McGuire drawing MCFD-2553-02.01, "Flow Diagram of Reactor Coolant System," indicates that valves 2NC0264, 2NC0266, and 2NC0252 and interconnecting piping is Duke Class C but is not within the scope of the LRA. Section 2.1.1.1.1 of the LRA states that Duke Class C piping is within the scope of license renewal. Explain why the Duke Class C piping and components of the reactor coolant system are not within the scope of license renewal.

Response to RAI 2.3.1-6

The Class C piping on drawing MCFD-2553-02.01 containing valves 2NC0264, 2NC0266 and 2NC0052 (not 2NC0252 as the RAI states) is within the scope of license renewal. While the piping is within the license renewal boundary defined by license renewal flags, highlighting was inadvertently omitted from that segment of piping. Piping and valve components in this segment of piping are contained in Table 3.3-41(page 3.3-239, rows 2, 3, 4, 5; page 3.3-240, rows 2, 3, 4, and 5) of the Application.

Reactor Coolant System Class 1 Piping, Valves and Pump Casings

RAI 3.1.1-1
Per LRA Table 3.1-1, the loss of material and cracking in orifices are managed by the chemistry control program. Since these restricting orifices are relied upon to separate Class 1 portions from Class 2 portion of the reactor coolant system (RCS) piping in lieu of redundant valves, their continued functionality is extremely important to maintaining the current licensing basis (CLB). It is not evident to the staff how the effectiveness of the chemistry control program to manage loss of material and cracking is verified. No supplemental inservice inspection (ISI) or performance testing is identified. Clarify how the aging effects associated with orifices are adequately managed by the chemistry control program alone, and provide a description of supplemental activities which verify that the chemistry control program is effective.

Response to RAI 3.1.1-1
The *Chemistry Control Program* maintains the environment in the Reactor Coolant System by controlling contaminants that lead to loss of material and cracking. A review of the operating experience has not identified any failures of Reactor Coolant System components, including these orifices, 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.

RAI 3.1.2 Pressurizer

RAI 3.1.2-1

Section 3.1 of the LRA does not assess whether the potential exists for existing cracks in the pressurizer cladding to grow (as a result of thermal-fatigue induced crack growth) through the cladding and into the ferritic portions of the pressurizer subcomponents that the cladding is joined to. Discuss whether thermal fatigue-induced crack initiation and growth is an issue for the ferritic pressurizer subcomponents that are protected with austenitic stainless steel cladding, and whether propagation of the cracks through the cladding into the ferritic base material or weld material beneath the clad is an applicable effect that requires management. If propagation of the cracks through the cladding into the ferritic base material or weld material beneath the clad is an applicable effect that requires management, state which aging management programs (AMPs) will be used to manage this effect, and justify why you consider the AMPs to be sufficient to manage this effect during the extended periods of operation.

Response to RAI 3.1.2-1

Cracking of the pressurizer cladding, including welds that attach internal items to the cladding (e.g., heater support brackets), is an aging effect requiring management for license renewal. As specified in NUREG-1723, the staff is concerned that cracks in the cladding may extend into the underlying ferritic steel, and subsequent growth of the crack may propagate and remain undetected.

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. If cracking were to occur at the surface of the surge nozzle cladding and propagate to the base metal, volumetric examinations performed in accordance with ASME Section XI, Examination Category B-D, would detect the flaw prior to loss of the pressurizer intended function.

RAI 3.1.2-2
The staff is concerned that inter-granular stress corrosion cracking 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. The staff considers that these welds will not require aging management in the period of extended operation if the applicant can provide reasonable justification that sensitization has not occurred in these welds during the fabrication of these components. Provide a discussion of how the implementation of plant-specific procedures and quality assurance requirements, if any, for the welding and testing of these austenitic stainless steel components provides reasonable assurance that sensitization has not occurred in these welds and associated heat-affected zones.

Response to RAI 3.1.2-2
The possibility that sensitized areas exist in the 304 stainless steel supports or their welds cannot be precluded even with material selection and manufacturing processes that minimize sensitization.

The *Chemistry Control Program* which precludes stress corrosion cracking in other pressurized water reactor primary system materials is also effective in preventing stress corrosion cracking in these pressurizer components and welds. Rigorous control of oxygen and chlorides provides a benign environment which has been shown to be effective both in laboratory experiments and years of operating experience.

As discussed in the Catawba UFSAR Section 5.2.5.5 (page 5.2-33), the presence of sensitized stainless steel material does not necessarily result in any increase in susceptibility to intergranular stress corrosion cracking. Note that even in laboratory cases where severely sensitized stainless steels have been deliberately exposed to pressurized water reactor environments, no intergranular attack has been observed.

In summary, the *Chemistry Control Program* is an adequate aging management program to preclude stress corrosion cracking in the pressurizer internal attachment welds for the period of extended operation for the following reasons:

1. Studies and operating experience have shown that pressurized water reactor environments do not lead to stress corrosion cracking in sensitized stainless steel.
2. Service experience has demonstrated that stress corrosion cracking does not occur in stainless steels in a pressurized water reactor environment, whether or not they are sensitized.

RAI 3.1.2-3

LRA Table 3.1-1 identifies loss of preload as an aging effect for the manway cover bolts/studs. Table 3.1-1 also indicates that the aging effects associated with the bolts/studs will be managed using the inservice inspection plan and the fluid leak management program. From the description provided in LRA Appendix B for these two AMPs, it is not clear how loss of preload will be managed for the period of extended operation. Clarify how the inservice inspection plan and the fluid leak management program are sufficient to manage loss of preload of the manway cover bolts/studs.

Response to RAI 3.1.2-3

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. If there was a loss of mechanical closure integrity, there would be leakage, which 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 *Inservice Inspection Plan.*

3.1.3 Reactor Vessel and Control Rod Drive Mechanism Pressure Boundary

RAI 3.1.3-1

(a) In accordance with LRA Table 3.1-1, aging effects of cracking and loss of material associated with the thimble seal table are managed by the chemistry control program alone. Since mechanical seals between the retractable thimbles and the conduits are provided at the seal table, its continued functionality is extremely important for maintaining the CLB. The staff requests clarification on how the effectiveness of the chemistry control program to manage loss of material and cracking is verified, since no supplemental ISI or performance testing to quantify these effects is identified.

Response to RAI 3.1.3-1

In addition to the *Chemistry Control Program,* the mechanical seals are visually inspected during startup from each outage to ensure they are not leaking. The high pressure seals are disconnected every outage so that the flux thimbles may be retracted during refueling. Prior to restart, the flux thimbles are reinserted and the high pressure seal is reinstalled. These connections are visually inspected for leakage during startup of the units. This inspection is part of the *Inservice Inspection Plan*, ASME Section XI, Table IWB-2500, Examination Category B-P. Table 3.1-1 of the Application is supplemented with the addition of *Inservice Inspection Plan* to manage aging for the thimble seal table (page 3.1-14, row 3):

Component Type	Component Function	Material	Environment	Aging Effect	Aging Management Programs and Activities
Reactor Vessel and CRDM Pressure Boundary Components (continued)					
Thimble Seal Table	PB	Stainless Steel	Borated Water	Cracking Loss of Material	Chemistry Control Program Inservice Inspection Plan

3.1.4 Reactor Vessel Internals

RAI 3.1.4-1

In LRA Table 3.1-1, the applicant does not list the rod control cluster assembly guide tube support pins as a separate entry. The staff assumes that they are included with the guide tube assembly. Confirm whether the guide tube support pins at McGuire and Catawba are within the scope of license renewal, and whether the AMRs for the guide tube assemblies in Table 3.1-1 of the application (on pages 3.1-16 and 3.1-17 of the LRA) covers the scope of your AMR for the guide tube support pins. If the guide tube support pins are within scope of license renewal and Table 3.1-1 does not provide an AMR for them, provide an AMR for the guide tube support pins that identifies the aging effects that are applicable to the pins and the aging programs that will be capable of managing the effects.

Response to RAI 3.1.4-1

The guide tube support pins, "split pins," are included within the guide tube assemblies entry in Table 3.1-1 (page 3.1-16, row 3) of the Application. The split pins are fabricated from Type 316 cold worked stainless steel which has the same aging effects as the other stainless steel components in the guide tube assemblies.

RAI 3.1.4-2

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 reactor vessel internal for the lower support plate (forging) and lower core support columns. These materials are fabricated from austenitic stainless steel. In NUREG/CR-6048, Oakridge National Laboratory, on behalf of the NRC, has used 5×10^{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. In order to substantiate that loss of fracture toughness is not an applicable effect for these components, confirm that accumulated neutron fluence (E > 1 MeV) for these components during the extended period of operation will be lower than this threshold for radiation induced embrittlement. If the fluence levels for the lower support plate (forging) and lower core support columns are projected to be greater than 5×10^{20} neutrons/cm^2 (E > 1 MeV), discuss how you will manage reduction in fracture toughness in these components during the proposed extended periods of operation for the McGuire and Catawba units.

Response to RAI 3.1.4-2

The maximum projected fluence for the lower support forging at 54 EFPY is approximately 5×10^{18} neutrons/cm^2 (E > 1 MeV) which is less that the threshold fluence value stated in the RAI. Therefore, the lower support forging is not expected to experience reduction of fracture toughness.

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 $5x10^{21}$ neutrons/cm^2 (E > 1 MeV). Because the projected fluence at the top portion of the support columns exceeds the threshold $5x10^{20}$ neutrons/cm^2 (E > 1 MeV), reduction in fracture toughness will be included as an aging effect for the lower core support columns. This aging effect will be managed by the *Reactor Vessel Internals Inspection Program.* Table 3.1-1 of the Application is supplemented with the addition of reduction of fracture toughness as an aging effect managed by the *Reactor Vessel Internals Inspection Program* for the lower core support columns. 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
Lower Core Support Structure					
Lower Core Support Columns	1,3,4,5,6	Stainless Steel	Borated Water	Cracking Loss of Material Reduction in Fracture Toughness	Chemistry Control Program Inservice Inspection Plan Reactor Vessel Internals Inspection Program

RAI 3.1.4-3
In LRA 3.1-1 you list dimensional changes (as a result of radiation-induced void swelling) as an applicable effect for some reactor vessel internal components, but not for others. Confirm that the reactor vessel internal components that you have identified as being potentially susceptible to this effect are the limiting dimensional change (due to void swelling) locations within the reactor vessel cavity, as evaluated from an accumulated neutron fluence basis for the components.

Response to RAI 3.1.4-3
Uncertainty currently exists relative to the prediction of void swelling in pressurized water reactor conditions. This uncertainty is based on the fact that existing swelling data has been obtained from materials that were not irradiated in a pressurized water reactor 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 is not available that shows a specific threshold for the onset of void swelling in solution annealed Type 304 stainless steel in a pressurized water reactor 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 *(Effects of Radiation on Materials, ASTM STP725, Comparison of High-Fluence Swelling Behavior of Austenitic Stainless Steels, Page 484).* Pressurized water reactors operate at approximately 315 °C well below 440 °C. Duke conservatively estimated all reactor vessel internal components, which 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 the Application 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, irradiation and specimen holder fasteners. These locations do not fall within that 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 pressurized water reactors 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 phenomena of void swelling, as well as the safety significance. As understanding of the phenomena of void swelling increases, Duke will adjust programmatic management of the 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 *Reactor Vessel Internals Inspection* described in Appendix B.3.27 of the Application identifies the committed actions with respect to inspection of the internals for void swelling.

RAI 3.1.4-4 (from NRC lettered dated January 30, 2002)
The McGuire and Catawba UFSARs describe that the main radial support for the lower end of the core barrel is accomplished by "key" and "keyway" joints to the reactor vessel wall. In regard to these joints, an Inconel clevis block is welded to the vessel inner circumference at equally spaced points. Another Inconel insert block is bolted to each of these blocks and has a "keyway" geometry. Opposite each of these is a "key" which is attached to the internals. According to WCAP-14577, License Renewal Evaluation: Aging Management for Reactor Internals, the clevis insert bolts (fasteners) are susceptible to loss of preload due to stress relaxation during normal operation. In LRA Table 3.1-1, the applicant has not identified loss of preload as an applicable aging effect for the clevis insert fasteners. Discuss the technical basis for not including loss of preload as an applicable aging effect for the clevis insert fasteners.

Response to RAI 3.1.4-4
Upon further review, Duke has determined that "loss of preload" could be an applicable aging effect for the clevis insert bolts. The effects of loss of preload on the clevis inserts would be expected to be loose, cracked, or missing bolts or fasteners. Since a VT-3 examination may not be sufficient to detect cracking, Duke will perform a VT-1 examination of the clevis insert fasteners each inspection interval. Table 3.3-1 of the Application (page 3.1-20, row 1) is supplemented to include loss of preload.

Component Type	Component Function	Material	Environment	Aging Effect	Aging Management Programs and Activities
Lower Core Support Structure					
Clevis Inserts and fasteners	1	Nickel Based Alloy	Borated Water	Cracking Loss of Material Loss of Preload	Alloy 600 Aging Management Review Chemistry Control Program Inservice Inspection

The following statement will be added to Section 18.2.16 for and McGuire and Section 18.2.15 for Catawba in the respective UFSAR Supplement:

A VT-1 examination of the reactor vessel internals clevis insert fasteners will be performed in lieu of the VT-3 examination currently required by ASME Section XI.

3.1.5 Steam Generator

RAI 3.1.5-1

Per Table 3.1-1, the 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. No supplemental ISI or performance testing is identified for these SG components. Clarify how the Chemistry Control Program by itself is sufficient to manage loss of material and cracking in these components.

Response to RAI 3.1.5-1

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.

RAI 3.1.5-2
In accordance with UFSAR Section 5.4.2.4 for Catawba, the Unit 2 Westinghouse SGs are equipped with a preheater and feedwater flow restrictor with main feedwater delivered just above the tubesheet while the feedwater in the Unit 1 BWI RSGs delivered to the annulus area outside the top of the tube bundle and distributed by a feedring header. It is not clear if the feedwater delivery systems in BWI RSGs at Catawba 1, McGuire 1 and McGuire 2 have flow restrictors.

1. Clarify if the feedwater flow restrictors are present in all four subject plant SG units.

2. Table 3.1-1 identifies the Inservice Inspection Plan and the Chemistry Control Program to detect cracking and loss of material in the flow restrictors and steam flow limiters. Describe the types of inservice inspections performed on these components.

Response to RAI 3.1.5-2
Note: Table 3.3-1 of the Application (page 3.1-24 row 4) incorrectly includes the steam outlet nozzle for Catawba Unit 2(nickel based alloy material). The Catawba Unit 2 steam outlet nozzles are correctly shown in Table 3.3-1 of the Application (page 3.1-25 row 3).

For Item (1), feedwater flow restrictor as identified in the Catawba UFSAR and the "feedwater limiter" listed in Table 3.1-1 (page 3.1-24, row 4) of the Application are synonymous. The feedwater limiters are only present in the Catawba Unit 2 steam generators. The *Chemistry Control Program* provides aging management for the feedwater limiter.

For Item (2), the steam flow restrictor identified in Table 3.1-1 (page 3.1-25, row 1) of the Application as the "flow restrictor," incorrectly shows the *Inservice Inspection Plan* as an aging management program. The *Chemistry Control Program* provides aging management for the steam flow restrictor.

4.2 Reactor Vessel Neutron Embrittlement

RAI 4.2-1

In Tables 4.2-1 through 4.2-4 of the application you provide some time-limited aging analyses for upper shelf energies of beltline nozzle plates/forging materials and nozzle weld materials in the McGuire and Catawba vessels. In contrast you did not perform a corresponding pressurized thermal shock assessments for these materials, as would normally be done in Tables 4.2-5 through 4.2-8 of the application. In addition, the staff is not aware that the unirradiated Charpy impact, unirradiated initial RT_{NDT} data (i.e., $RT_{NDT(U)}$ data) and upper shelf energy data and alloying chemistry data (especially copper and nickel contents, as well as phosphorous and sulfur contents) for these nozzle materials have been place on the "dockets" for the McGuire and Catawba reactor units (Dockets 50-369, 50-370, 50-413 and 50-414). With respect to these materials:

1. Submit 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. Submit the unirradiated Charpy impact data, unirradiated initial RT_{NDT} data (i.e., $RT_{NDT(U)}$ data), unirradiated upper shelf energy 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). Provide your bases for the data being docketed.

Response to RAI 4.2-1

The response to RAI 4.2-1 is provided in three parts. First, Duke incorrectly represented the nozzle region USE values as limiting. Duke will correct errors found in Section 4.2.1 of the Application during the preparation of the Reponses to RAI 4.2-1. Then, Duke will provide its responses to Items (1) and (2) of RAI 4.2-1.

Section 4.2.1 of the Application addresses Upper Shelf Energy (USE). During the preparation of the responses to this RAI, Duke identified errors in Tables 4.2-1 through 4.2-4, which are contained in Section 4.2.1. The calculated USE values for the nozzle region materials presented in these four tables were incorrectly based on peak beltline ¼T end of life (EOL) fluences that are substantially higher than the actual estimated fluence in the nozzle region.

Some of the nozzle region locations have an estimated 60 year fluence greater than 10^{17} neutrons/cm^2. Therefore, in accordance with 10 CFR 50 Appendix H, Duke has performed an analysis of nozzle region locations and has 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 on-site 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. Table 4.2-1A provides the correct USE values for the bounding nozzle region locations and supercedes the USE values for the nozzle region materials previously provided in Section 4.2.1 of the Application:

Table 4.2-1A
Revised Evaluation of Upper Shelf Energy
for Bounding Nozzle Region Locations at 54 EFPY

Material	Weight % of Cu	¼T Fluence (E > 1 MeV) (neutrons/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)	Projected USE @ 54 EFPY (ft-lb)
McGuire Unit 1					
Bounding Nozzle Shell Material	0.14	5.83 E + 17	68	12.5	59.8
Bounding Nozzle Weld Material	0.213	5.83 E + 17	109	19.0	88.3
McGuire Unit 2					
Bounding Nozzle Shell Material	0.16	1.12 E + 18	98	13.9	84.4
Bounding Nozzle Weld Material	0.039	1.12 E + 18	>87	10.8	77.6
Catawba Unit 1					
Bounding Nozzle Shell Material	0.09	2.01 E + 18	60	13.3	52.0
Bounding Nozzle Weld Material	0.04	2.01 E + 18	92	13.3	79.7
Catawba Unit 2					
Bounding Nozzle Shell Material	0.11	6.26 E + 17	65	10.0	58.5
Bounding Nozzle Weld Material	0.156	6.26 E + 17	102	16.0	85.7

In response to Item (1) of RAI 4.2-1, Table 4.2-1B provides the pressurized thermal shock assessment for the bounding nozzle region materials for each vessel.

Table 4.2-1B
Pressurized Thermal Shock Assessments for the Bounding Nozzle Region Location for Each Reactor Vessel

Material	CF	Surface Fluence (E > 1 MeV) (neutrons/cm²)	FF	$RT_{NDT(U)}$ °F	ΔRT_{PTS}	M	RT_{PTS} °F
McGuire Unit 1							
Bounding Nozzle Shell Material	104.75	9.79 E + 17	0.41	60	43.2	34	137.2
Bounding Nozzle Weld Material	208.2	9.79 E + 17	0.41	-50	85.9	56	91.9
McGuire Unit 2							
Bounding Nozzle Shell Material	118.3	1.86 E + 18	0.55	25	65.3	34	124.3
Bounding Nozzle Weld Material	52.7	1.86 E + 18	0.55	0	29	29	58
Catawba Unit 1							
Bounding Nozzle Shell Material	58	3.34 E + 18	0.78	-4	40.5	34	70.5
Bounding Nozzle Weld Material	54	3.34 E + 18	0.78	0	37.7	37.7	75.4
Catawba Unit 2							
Bounding Nozzle Shell Material	77	1.05 E + 18	0.43	50	32.9	32.9	115.8
Bounding Nozzle Weld Material	81	1.05 E + 18	0.43	-40	34.6	34.6	29

In response to Item (2) of RAI 4.2-1, Table 4.2-1C provides the requested information for the bounding nozzle region materials for each vessel; except that the unirradiated Charpy impact data of the nozzle region materials are not available.

Table 4.2-1C
Selected Upper Shelf Energy Materials Data for the Bounding Nozzle Region Location for Each Reactor Vessel

Material	Unirradiated Initial RT_{NDT} °F	Unirradiated USE (ft-lb)	Cu (wt%)	Ni (wt%)	P (wt%)	S (wt%)
McGuire Unit 1						
Bounding Nozzle Shell Material	60	68	0.14	0.79	0.013	0.016
Bounding Nozzle Weld Material	-50	109	0.213	0.867	0.016	0.016
McGuire Unit 2						
Bounding Nozzle Shell Material	25	98	0.153	0.89	0.012	0.012
Bounding Nozzle Weld Material	0	>87	0.039	0.75	0.010	0.015
Catawba Unit 1						
Bounding Nozzle Shell Material	-4	60	0.09	0.86	0.013	0.015
Bounding Nozzle Weld Material	0	92	0.04	0.75	0.009	0.015
Catawba Unit 2						
Bounding Nozzle Shell Material	50	65	0.11	0.85	0.011	0.020
Bounding Nozzle Weld Material	-40	102	0.156	0.14	0.016	0.009

Based on the data provided in response to this RAI, the bounding nozzle region materials do not exceed the regulatory limits of PTS and USE nor are they required to be considered limiting materials as part of the reactor vessel surveillance program.

The following are commitments:

1. As a result of the responses to this RAI, Duke will review changes to McGuire UFSAR Section 5.4.3 as contained in the McGuire UFSAR Supplement to determine the appropriate changes that should be made.

2. As a result of the responses to this RAI, Duke will review changes to Catawba UFSAR Section 5.3.3 as contained in the Catawba UFSAR Supplement to determine the appropriate changes that should be made.

4.3 Metal Fatigue

RAI 4.3-1

Section 4.3.1 of the LRA discusses the Duke evaluation of the fatigue TLAA for ASME Class 1 components. The discussion indicates that Duke will rely on its Thermal Fatigue Management Program (TFMP) to assure that component fatigue evaluations remain valid for the period of extended operation. Tables 5-2 and 5-49 of the of the McGuire UFSAR and Table 3-50 of the Catawba UFSAR contain a list transient design conditions and associated design cycles. Provide the following information for each transient listed in these tables:

1. 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.

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

Response to RAI 4.3-1

The number of current operating cycles along with the number of cycles estimated for 60-years of plant operation are provided in Table 4.3-1 herein. For McGuire Unit 1 and Unit 2, the current unit cycles and projected unit cycles for each unit are presented in Table 4.3-1(M1) and Table 4.3-1(M2), respectively. For the Replacement Steam Generators (RSGs) (Table 5-49 of the McGuire UFSAR), in lieu of a current and projected cycles, comments are provided for each transient in Table 4.3-1(RSG). During the preparation of the response to this RAI, Duke identified the need to enhance the *Thermal Fatigue Management Program* to address several transients listed in McGuire UFSAR Table 5-49. A corrective action report has been entered into the corrective action program to evaluate enhancements to the *Thermal Fatigue Management Program* to address these RSG transients. For Catawba Unit 1 and Unit 2, the current unit cycles and projected unit cycles for each unit are presented in Table 4.3-1(C1) and Table 4.3-1(C2), respectively.

In response to Item (1) of RAI 4.3-1, the method used to determine the number and severity of the design transients from plant operating history is as follows. Plant operating conditions are continually monitored for conditions that meet the definition of a transient monitored by the *Thermal Fatigue Monitoring Program.* Upon discovery of each transient cycle required to be documented by the program, an entry is made into a database. For each cycle that is required to be counted, the *Thermal Fatigue Management Program* specifies appropriate parameters, such as minimum/maximum temperature limits and rates of temperature change that are assumed in the analysis. The logging process captures these values for review. This process captures both the number and severity of design transients that occur throughout the plant operating history.

In response to Item (2) of RAI 4.3-1, the method used to determine the projected number of cycles at 60 years of operation is as follows. A reasonable rate of occurrence was determined by considering both the total occurrences of a transient to date and the recent rate of occurrence for each transient. This accounts for the fact that the rate of occurrence for some transients is not linear. The rate of occurrence is multiplied by the remaining years of operation to determine the number of projected transient cycles at year 60.

Table 4.3-1(M1)

McGuire Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
	Normal Conditions			
1.	Heatup/Startup at ≤ 100 ºF/hr for 200 ºF ≤ T_{AVE} ≤ 551ºF	200	54	123
2.	Shutdown/Cooldown ≤ 100 ºF/hr for 200 ºF ≤ T_{AVE} ≤ 551ºF	200	53	120
3.	Pressurizer Cooldown ≤ 200 ºF/hr for 200 ºF ≤ T_{PZR} ≤ 650ºF	200	Note 3	N/A
4.	Unit loading at 5% of full power/min	18,300	Note 4	N/A
5.	Unit unloading at 5% of full power/min	18,300	Note 4	N/A
6.	Step load increase of 10% of full power	2,000	Note 5	N/A
7.	Step load decrease of 10% of full power	2,000	Note 5	N/A
8.	Large step load decrease, with steam dump (100% to 0% of rated thermal power with steam dump)	200	26	44
9.	Steady state fluctuations	∞	Note 5	N/A
	Upset Conditions			
10.	Loss of load, without immediate turbine or reactor trip	80	4	6
11.	Loss of power (blackout with natural circulation in the Reactor coolant System)(Loss of offsite AC electrical power source supplying the Onsite Class 1E Distribution System)	40	3	4
12.	Loss of flow (partial loss of flow one pump only) in only one Reactor Coolant Loop	80	4	6

Table 4.3-1(M1)

McGuire Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
13.	Reactor trip from full power (100% to 0% of rated thermal power)	400	74	140
14.	Inadvertent auxiliary spray	10	0	0
15.	Operating Basis Earthquake (OBE) • Steam Generator • Reactor Coolant Pump (20 earthquakes of 20 cycles each) • Pressurizer (20 earthquakes of 20 cycles each) • Reactor Vessel	600 cycles 400 cycles 400 cycles 50 cycles	OBE cycles are not counted	OBE cycles are not counted
	Faulted Conditions			
16.	Main reactor coolant branch line pipe break (Break in a reactor coolant pipe ≥ 6 inches equivalent diameter)	1	Faulted Events are not counted	Faulted Events are not counted
17.	Steam pipe break (Break in steam line ≥ 6.0 inches equivalent diameter)	1	Faulted Events are not counted	Faulted Events are not counted
18.	Steam generator tube rupture	8	Faulted Events are not counted	Faulted Events are not counted
19.	Safe Shutdown Earthquake	10 cycles	Faulted Events are not counted	Faulted Events are not counted

Table 4.3-1(M1)

McGuire Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
	Test Conditions			
20.	Turbine roll test	10	3	3
21.	Hydrostatic test conditions – Primary side (pressurized to 3107 psig)	5	1	1
22.	Hydrostatic test conditions – Secondary side (pressurized to 1481 psig)	10	2	2
23.	Primary side leak test (pressurized to 2500 psig)	50	26	39

Notes for Table 4.3-1(M1):

N/A = Not Applicable

1. McGuire UFSAR Table 5-2, Summary of Reactor Coolant System Design Transients.
2. Current cycles based on data as of 2001.
3. The counts for the Pressurizer are assumed to be the same as for the unit as a whole.
4. Due to the plant's operation as a base load plant rather than a load-follow plant, this transient need not be counted.
5. This transient causes insignificant fatigue and therefore counting is not needed.

Table 4.3-1(M2)

McGuire Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
	Normal Conditions			
1.	Heatup/Startup at ≤ 100 ºF/hr for 200 ºF ≤ T_{AVE} ≤ 551ºF	200	34	110
2.	Shutdown/Cooldown ≤ 100 ºF/hr for 200 ºF ≤ T_{AVE} ≤ 551ºF	200	36	109
3.	Pressurizer Cooldown ≤ 200 ºF/hr for 200 ºF ≤ T_{PZR} ≤ 650ºF	200	Note 3	N/A
4.	Unit loading at 5% of full power/min	18,300	Note 4	N/A
5.	Unit unloading at 5% of full power/min	18,300	Note 4	N/A
6.	Step load increase of 10% of full power	2,000	Note 5	N/A
7.	Step load decrease of 10% of full power	2,000	Note 5	N/A
8.	Large step load decrease, with steam dump (100% to 0% of rated thermal power with steam dump)	200	26	41
9.	Steady state fluctuations	∞	Note 5	N/A
	Upset Conditions			
10.	Loss of load, without immediate turbine or reactor trip	80	3	3
11.	Loss of power (blackout with natural circulation in the Reactor coolant System)(Loss of offsite AC electrical power source supplying the Onsite Class 1E Distribution System)	40	1	5
12.	Loss of flow (partial loss of flow one pump only) in only one Reactor Coolant Loop	80	2	6

Table 4.3-1(M2)

McGuire Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
13.	Reactor trip from full power (100% to 0% of rated thermal power)	400	61	129
14.	Inadvertent auxiliary spray	10	0	0
15.	Operating Basis Earthquake • Steam Generator • Reactor Coolant Pump (20 earthquakes of 20 cycles each) • Pressurizer (20 earthquakes of 20 cycles each) • Reactor Vessel	 600 cycles 400 cycles 400 cycles 50 cycles	OBE cycles are not counted	OBE cycles are not counted
	Faulted Conditions			
16.	Main reactor coolant branch line pipe break (Break in a reactor coolant pipe ≥ 6 inches equivalent diameter)	1	Faulted Events are not counted	Faulted Events are not counted
17.	Steam pipe break (Break in steam line ≥ 6.0 inches equivalent diameter)	1	Faulted Events are not counted	Faulted Events are not counted
18.	Steam generator tube rupture	8	Faulted Events are not counted	Faulted Events are not counted
19.	Safe Shutdown Earthquake	10 cycles	Faulted Events are not counted	Faulted Events are not counted

Table 4.3-1(M2)

McGuire Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
	Test Conditions			
20.	Turbine roll test	10	3	3
21.	Hydrostatic test conditions – Primary side (pressurized to 3107 psig)	5	1	1
22.	Hydrostatic test conditions – Secondary side (pressurized to 1481 psig)	10	2	2
23.	Primary side leak test (pressurized to 2500 psig)	50	18	34

Notes for Table 4.3-1(M2):

N/A = Not Applicable

1. McGuire UFSAR Table 5-2, Summary of Reactor Coolant System Design Transients.
2. Current cycles based on data as of 2001.
3. The counts for the Pressurizer are assumed to be the same as for the unit as a whole.
4. Due to the plant's operation as a base load plant rather than a load-follow plant, this transient need not be counted.
5. This transient causes insignificant fatigue and therefore counting is not needed.

Table 4.3-1(RSG)

BWI Replacement Steam Generator – McGuire Units 1 & 2

Transient Number	Transient Description	Design Cycles (Note 1)	Comment
Normal (Level A) Transients			
1.	Plant Heatup	400	Note 2
2.	Plant Cooldown	400	Note 2
3.	Plant Loading	19,800	Note 3
4.	Plant Unloading	19,800	Note 3
5.	Small Step Load Increase 15 – 25%	300	Note 4
6.	Small Step Load Increase 90 – 100%	2700	Note 4
7.	Small Step Load Decrease 25 – 15%	300	Note 4
8.	Small Step Load Decrease 100 – 90%	2700	Note 4
9.	Large Step Load Decrease	300	Note 2
10.	Feedwater Cycling at No Load	7500	Note 4
11.	Steady State Fluctuations ± 3°F, ± 50 psig	2.25×10^5	Note 4
12.	Steady State Fluctuations ± 0.5°F, ± 6 psig	4.5×10^6	Note 4
13.	Steady State Fluctuations +11°F, - 0°F ± 0 psig	3.00×10^7	Note 4
14.	Plant Loading between 0% and 15% power	750	Note 5
15.	Plant Unloading between 15% and 0% power	750	Note 5
16.	Loop Out of Service – Normal Pump Shutdown	120	Note 4
17.	Loop Out of Service – Normal Pump Startup	105	Note 4
18.	Boron Concentration Equalization	39, 600	Note 4

Table 4.3-1(RSG)

BWI Replacement Steam Generator – McGuire Units 1 & 2

Transient Number	Transient Description	Design Cycles (Note 1)	Comment
19.	Reactor Coolant Pump Startup/Shutdown – Cold Conditions	750	Note 5
20.	Reactor Coolant Pump Startup/Shutdown – Hot Conditions	3750	Note 5
21.	RCS Venting – Affected Loops	480	Note 5
22.	RCS Venting – Unaffected Loops	1440	Note 5
23.	Vacuum Refill	480	Note 4
24.	Swap of main feedwater supply from the auxiliary to the main feedwater nozzle without tempering flow	200	Note 6
25.	Swap of main feedwater supply from the auxiliary to the main feedwater nozzle with tempering flow	750	Note 6
Upset (Level B) Transients			
26.	Loss of Load	120	Note 2
27.	Loss of Power	60	Note 2
28.	Partial Loss of Flow	120	Note 2
29.	Reactor Trip from Full Power – Nominal	450	Note 2
30.	Reactor Trip from Full Power – Inadvertent Heatup	300	Note 5
31.	Reactor Trip from Full Power – Inadvertent Cooldown	15	Note 2
32.	Inadvertent RCS Depressurization	30	Note 5
33.	Inadvertent Startup of an Inactive Loop	15	Note 5
34.	Control Rod Drop	120	Note 5

Table 4.3-1(RSG)

BWI Replacement Steam Generator – McGuire Units 1 & 2

Transient Number	Transient Description	Design Cycles (Note 1)	Comment
35.	Operating Basis Earthquake (OBE)	30	20 cycles per occurrence – OBE cycles are not counted
36.	Excessive Feedwater Flow	45	Note 5
37.	Inadvertent Safety Injection Actuation	90	Note 2
38.	Excessive Bypass Feedwater	60	Note 5
39.	Cold Feedwater to Dry, Pressurized RSG	2	Note 7
40.	Complete Loss of Flow	8	Note 5
Emergency (Level C) Transients			
41.	Small Loss of Coolant Accident	8	Emergency Events are not counted
42.	Small Steam Line Break	8	Emergency Events are not counted
Faulted (Level D) Transients			
43.	Reactor Coolant Pipe Break (Large LOCA)	N/A	Faulted Events are not counted
44.	Large Steam Line Break	1	Faulted Events are not counted
45.	Feedwater Line Break	1	Faulted Events are not counted
46.	Safe Shutdown Earthquake (SSE)	1	Faulted Events are not counted
47.	Locked Rotor	1	Faulted Events are not counted
48.	Rod Ejection	1	Faulted Events are not counted

Table 4.3-1(RSG) BWI Replacement Steam Generator – McGuire Units 1 & 2			
Transient Number	**Transient Description**	**Design Cycles (Note 1)**	**Comment**
49.	Steam Generator Tube Rupture	8	Faulted Events are not counted
50.	Cold Feedwater to Dry, Depressurized RSG	1	Faulted Events are not counted
Test Conditions			
51.	Primary Side Hydrostatic Test	10	Note 2
52.	Secondary Side Hydrostatic Test	10	Note 2
53.	Primary Side Leakage Test	200	Note 2
54.	Secondary Side Leakage Test	80	Note 5
55.	Tube Leak Test – Secondary Side Pressure 200	600	Note 5
56.	Tube Leak Test – Secondary Side Pressure 400	300	Note 5
57.	Tube Leak Test – Secondary Side Pressure 600	180	Note 5
58.	Tube Leak Test – Secondary Side Pressure 840	80	Note 5

Notes for Table 4.3-1(RSG):

N/A = Not Applicable

1. McGuire UFSAR Table 5-49, BWI Replacement Steam Generator.
2. Limited by the unit specific cycle limit to less than the RSG limit.
3. Due to the plant's operation as a base load plant rather than a load-follow plant, this transient need not be counted.
4. This transient causes insignificant fatigue and therefore counting is not needed.
5. A corrective action report has been entered into the corrective action program to evaluate revising the Thermal Fatigue Management Program to monitor this transient in the future.
6. Transient from Note 1 of McGuire UFSAR Table 5-49. A corrective action report has been entered into the corrective action program to evaluate revising the Thermal Fatigue Management Program to monitor this transient in the future.
7. This transient is will be addressed by monitoring of swap of main feedwater supply from the auxiliary to the main feedwater nozzle with or without tempering flow.

Table 4.3-1(C1)

Catawba Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
	Normal (Level A) Transients			
1.	Heatup/Startup	200	36	98
2.	Shutdown/Cooldown	200	35	97
3.	Plant Loading at 5% of full power	18,300	Note 3	N/A
4.	Plant Unloading at 5% of full power	18,300	Note 3	N/A
5.	Step load increase of 10% of full power	2,000	Note 4	N/A
6.	Step load decrease of 10% of full power	2,000	Note 4	N/A
7.	Large Step Load decrease (with steam dump)	200	14	38
8.	Steady State Fluctuations	∞	Note 4	N/A
9.	Pressurizer Safety Valve Operation	40	0	0
10.	Pressurizer Relief Valve Operation	100	25	33
11.	RTD Manifold Maintenance	50	Note 5	N/A
12.	Auxiliary Spray Actuation during Cooldown	200	3	4
13.	Refueling	80	Note 4	N/A
14.	Normal charging/letdown Shutoff and return to service	Note 6	N/A	N/A
15.	Letdown Trip with Prompt Return to Service	200	14	23
16.	Letdown Trip with Delayed Return to Service	20	13	20
17.	Charging Trip with Prompt Return to Service	20	Note 4	N/A
18.	Charging Trip with Delayed Return to Service	80 Note 6	2	3
19.	Charging Flow 50% Increase	24,000	Note 4	N/A

Table 4.3-1(C1)

Catawba Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
20.	Charging Flow 50% Decrease	24,000	Note 4	N/A
21.	Letdown Flow 40% Decrease and Return to Normal	2,000	Note 4	N/A
22.	Letdown Flow 60% Increase	24,000	Note 4	N/A
23.	Letdown Shutoff and Momentary Excess Letdown	100	Note 7	N/A
24.	Switch of Charging. Pump Suction	180	13	17
	Upset (Level B) Transients			
25.	Reactor Trip from Full Power	400	41	74
26.	Inadvertent Auxiliary Spray	10	0	0
27.	Loss of Power (Blackout with Natural Circulation)	40	2	6
28.	Loss of Load without Immediate Turbine or Reactor Trip	80	3	5
29.	Loss of Flow in One Loop	80	3	4
30.	Reactor Trip with Cooldown and Inadvertent SIS Actuation	10	1	2
31.	Inadvertent RCS Depressurization	20	1	2
32.	Inadvertent SI Accumulator Blowdown during Plant Cooldown	4	0	0
33.	High Head Safety Injection	22	1	5
34.	Boron Injection	48	4	5

Table 4.3-1(C1)

Catawba Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
Faulted (Level D) Transients				
35.	Large Steam Break	1	Faulted Events are not counted	Faulted Events are not counted
36.	Pipe Rupture	1	Faulted Events are not counted	Faulted Events are not counted
37.	High Head Safety Injection	2	Faulted Events are not counted	Faulted Events are not counted
38.	Boron Injection	2	Faulted Events are not counted	Faulted Events are not counted

Table 4.3-1(C1)

Catawba Unit 1, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 1 Cycles (Note 2)	Projected Unit 1 Cycles
Test Conditions				
39.	Turbine Roll Test	10	3	3
40.	Hydrostatic Test	5	1	1
41.	Primary Side Leak Test	50	13	26
42.	Inadvertent Auxiliary Spray	1	1	1

Notes for Table 4.3-1(C1):

N/A = Not Applicable

1. Catawba UFSAR Table 3-50, Design Transients for ASME Code Class 1 Piping.
2. Current cycles based on data as of 2001.
3. Due to the plant's operation as a base load plant rather than a load-follow plant, this transient need not be counted.
4. This transient causes insignificant fatigue and therefore counting is not needed.
5. RTD Manifold has been permanently removed from service.
6. Normal charging/letdown Shutoff and Return to Service is essentially identical to and is thus absorbed into Charging Trip with Delayed Return to Service, which then has the combined total allowable occurrences.
7. This transient only affects a 1-inch Class 1 line, for which fatigue qualification is not required; therefore counting of cycles is not needed.

Table 4.3-1(C2)

Catawba Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
	Normal (Level A) Transients			
1.	Heatup/Startup	200	38	118
2.	Shutdown/Cooldown	200	37	117
3.	Plant Loading at 5% of full power	18,300	Note 3	N/A
4.	Plant Unloading at 5% of full power	18,300	Note 3	N/A
5.	Step load increase of 10% of full power	2,000	Note 4	N/A
6.	Step load decrease of 10% of full power	2,000	Note 4	N/A
7.	Large Step Load decrease (with steam dump)	200	11	42
8.	Steady State Fluctuations	∞	Note 4	N/A
9.	Pressurizer Safety Valve Operation	40	0	0
10.	Pressurizer Relief Valve Operation	100	18	28
11.	RTD Manifold Maintenance	50	Note 5	N/A
12.	Auxiliary Spray Actuation during Cooldown	200	10	13
13.	Refueling	80	Note 4	N/A
14.	Normal charging/letdown Shutoff and return to service	Note 6	N/A	N/A
15.	Letdown Trip with Prompt Return to Service	200	38	70
16.	Letdown Trip with Delayed Return to Service	20	10	13
17.	Charging Trip with Prompt Return to Service	20	Note 4	N/A
18.	Charging Trip with Delayed Return to Service	80 Note 6	2	2
19.	Charging Flow 50% Increase	24,000	Note 4	N/A

Table 4.3-1(C2)

Catawba Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
20.	Charging Flow 50% Decrease	24,000	Note 4	N/A
21.	Letdown Flow 40% Decrease and Return to Normal	2,000	Note 4	N/A
22.	Letdown Flow 60% Increase	24,000	Note 4	N/A
23.	Letdown Shutoff and Momentary Excess Letdown	100	Note 7	N/A
24.	Switch of Charging. Pump Suction	180	16	20
	Upset (Level B) Transients			
25.	Reactor Trip from Full Power	400	48	129
26.	Inadvertent Auxiliary Spray	10	0	0
27.	Loss of Power (Blackout with Natural Circulation)	40	1	5
28.	Loss of Load without Immediate Turbine or Reactor Trip	80	13	26
29.	Loss of Flow in One Loop	80	4	9
30.	Reactor Trip with Cooldown and Inadvertent SIS Actuation	10	1	1
31.	Inadvertent RCS Depressurization	20	0	0
32.	Inadvertent SI Accumulator Blowdown during Plant Cooldown	4	2	4
33.	High Head Safety Injection	22	1	1
34.	Boron Injection	48	5	9

Table 4.3-1(C2)

Catawba Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
	Faulted (Level D) Transients			
35.	Large Steam Break	1	Faulted Events are not counted	Faulted Events are not counted
36.	Pipe Rupture	1	Faulted Events are not counted	Faulted Events are not counted
37.	High Head Safety Injection	2	Faulted Events are not counted	Faulted Events are not counted
38.	Boron Injection	2	Faulted Events are not counted	Faulted Events are not counted

Table 4.3-1(C2)

Catawba Unit 2, Projected Cycles at 60 Years of Operation

Transient Number	Transient Description	Design Cycles (Note 1)	Current Unit 2 Cycles (Note 2)	Projected Unit 2 Cycles
Test Conditions				
39.	Turbine Roll Test	10	2	2
40.	Hydrostatic Test	5	1	1
41.	Primary Side Leak Test	50	12	16
42.	Inadvertent Auxiliary Spray	1	1	1

Notes for Table 4.3-1(C2):

N/A = Not Applicable

1. Catawba UFSAR Table 3-50, Design Transients for ASME Code Class 1 Piping.
2. Current cycles based on data as of 2001.
3. Due to the plant's operation as a base load plant rather than a load-follow plant, this transient need not be counted.
4. This transient causes insignificant fatigue and therefore counting is not needed.
5. RTD Manifold has been permanently removed from service.
6. Normal charging/letdown Shutoff and Return to Service is essentially identical to and is thus absorbed into Charging Trip with Delayed Return to Service, which then has the combined total allowable occurrences.
7. This transient only affects a 1-inch Class 1 line, for which fatigue qualification is not required; therefore counting of cycles is not needed.

RAI 4.3-2
The Westinghouse Owners Group issued Topical Report WCAP-14577, Revision 1-A, "Aging Management for Reactor Internals," to address the aging management of the reactor vessel internals (RVI). The staff review of WCAP-14577, Revision 1-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 11 specified in WCAP -14577, Revision 1-A indicates that the fatigue TLAA of the reactor vessel internals should be addressed on a plant specific basis. In the LRA, Duke indicates that the TFMP will assure that component fatigue analyses will remain within their design values for the period of extended operation. 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.

Response to RAI 4.3-2
RAI 4.3-2 seeks information related to a document that was not considered by Duke in the Application. Regarding the fatigue TLAA of reactor internals, no time-limited aging analyses were identified for the McGuire or Catawba reactor internals. The original design for the reactor vessel internals for all four units did not include any time-limited assumptions. The reactor vessel internals were designed to ASME Section III, Class 2 which specified no time or cycle-dependent requirements for the internals. Modifications to the original design were completed in 1999 for McGuire Unit 1, 2000 for McGuire Unit 2 and Catawba Unit 1 and 2001 for Catawba Unit 2 when the rod control cluster assembly guide tube support pins, "split pins," were replaced at each of the four units. Replacement split pins are the only reactor vessel internals parts with an explicit fatigue design basis.

The split pin replacement did consider low cycle fatigue, but considered it for 60 years, not 40 years, which is the definitional requirement for a TLAA under §54.21(c). Details of the split pin replacement including the considerations of low cycle fatigue were included in WCAP-15252, Revision 1 [Reference 1 below] which was approved by the NRC. Section 3.7 of WCAP-15252, Revision 1 describes a design based on a 60 year design life. Therefore, no license renewal TLAA issue exists. The transients that contribute to the fatigue usage of the split pins are included in those described in Response to RAI 4.3-1. So even though the transients are not associated with a reactor internals TLAA, the transient set is monitored by the *Thermal Fatigue Management Program.* The discussion of how the *Thermal Fatigue Management Program* monitors these transients is provided in the Application and in Response to RAI 4.3-1.

Reference 1
"Duke Energy Corporation, McGuire and Catawba Units 1 and 2, Replacement CW 316 Split Pins Design Qualification Report," WCAP-15252, Revision 1, Westinghouse Electric Company, LLC, March 2000.

RAI 4.3-3

The Westinghouse Owners Group 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. Tables 3-2 through 3-16 of WCAP-14575-A list RCS components where fatigue is considered significant. The staff review of WCAP-14575-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 8 requests that the applicant to address components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575-A. Duke indicates that the TFMP will assure that component fatigue analyses will remain within their design values for the period of extended operation. Discuss how the TFMP addresses the components labeled I-M and I-RA in Tables 3-2 through 3-16 of WCAP-14575-A.

Response to RAI 4.3-3

RAI 4.3-3 seeks information related to a document that was not considered by Duke in the Application. To better understand the request, Duke has reviewed WCAP-14575-A and notes that the components labeled I-M and I-RA in Tables 3-2 through 3-16 are Class 1 piping and pressure boundary components whose plant-specific counterparts were considered in the stress and fatigue analyses of original design. The thermal fatigue design basis for the McGuire and Catawba Class 1 piping components is managed by the *Thermal Fatigue Management Program.* The discussion of how the *Thermal Fatigue Management Program* manages the thermal fatigue design basis of these components is provided in the Application and in Response to RAI 4.3-1.

RAI 4.3-4

The Westinghouse Owners Group has issued the generic Topical Report WCAP-14574-A to address aging management of pressurizers. The staff review of WCAP-14574-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 1 requests that the applicant demonstrate that the pressurizer sub-component cumulative usage factors (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, including inflow/outflow thermal transients. Provide the following information:

1. Confirm that the additional transients discussed in WCAP-14574-A, not considered in the original design, have been addressed at McGuire and Catawba.

2. Show 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.

3. Discuss the impact of the environmental fatigue correlations provided in NUREG/CR-6583, "Effects of LWR [Light Water Reactor] 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," on the above results.

Response to RAI 4.3-4

RAI 4.3-4 seeks information related to a document that was not considered by Duke in the Application. To better understand the request, Duke has reviewed WCAP-14574-A and notes that Item 1 in the above request refers to off normal transients and other additional transients that, if applicable to a particular plant, were imposed on a plant-specific basis. Such transients, once analyzed, would then become part of that plant's design basis.

For the pressurizers at McGuire and Catawba, pressurizer insurge/outsurge is the only off normal or additional transient that has been analyzed and incorporated into the thermal fatigue design basis. To mitigate the effects of insurge/outsurge, McGuire and Catawba implemented modified operating procedures in the mid 1990's. Additionally, historical plant instrument data was analyzed to determine an insurge/outsurge history encompassing pre- and post-application of the modified operating procedures with an extrapolation for all appropriate design transient occurrences. Analysis of these occurrences of insurge/outsurge were analyzed and it was found that the CUF of the affected pressurizer parts will remain less than 1.0 for all appropriate design transient occurrences. As can be seen in RAI Response 4.3-1, management of all appropriate fatigue design transient occurrences allows the effects of insurge/outsurge on the pressurizer to be managed by the *Thermal Fatigue Management Program.* The discussion of how the *Thermal Fatigue Management Program* manages the thermal fatigue design basis is provided in the Application and in Response to RAI 4.3-1.

The information requested in Item 2 above asks for a comparison of Duke information to information in WCAP-14574-A which, again, is not an exercise valid to the Duke Application. The details of the design, including stress and fatigue analysis results, are contained in engineering documents maintained onsite and available for inspection. For the information requested in Item 3 above, refer to the Response to RAI 4.3-5 for additional discussion of fatigue reactor water effects and the Duke design.

RAI 4.3-5

Section 4.3.1.2 of the LRA discusses Duke's evaluation of the impact of the reactor water environment on the fatigue life of components. The discussion indicates that Duke's evaluation will use method 2 contained in draft Electric Power Research institute (EPRI) report, "Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application." 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." Provide the following additional information regarding the evaluation of reactor water environmental effects:

1. Confirm 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.

2. Provide the design basis usage factors for each of the six component locations listed in NUREG/CR-6260.

3. Note 1 of the Duke procedure indicates that ASME Section XI flaw tolerance and inspection procedures may be used as an alternative method to manage environmental fatigue. The NRC staff has not endorsed a procedure on a generic basis which allows for ASME Section XI inspections in lieu of meeting the fatigue usage criteria. Duke has not provided a technical basis demonstrating the technical adequacy of its proposal. Provide a detailed technical evaluation which demonstrates the proposed inspections provide an adequate technical basis for detecting fatigue cracking before such cracking leads to through wall cracking or pipe failure. The detailed technical evaluation should 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 alternative to the detailed technical evaluation, provide a commitment 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 is projected to exceed one.

4. Note 2 of the Duke procedure indicates that the environmental factor will be adjusted to 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 (Meeting summary dated March 1, 2001). Provide additional data and additional data evaluations that demonstrate (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, (2)

that environmental effects and surface effects are not independent effects. As an alternative, revise the Duke procedure to eliminate the use of the Z factor.

Response to RAI 4.3-5
In response to Item (1), Duke confirms 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 Duke must complete by year 2021. As stated in the Application, Duke may choose to exercise a different course of action should the NRC approve a less restrictive approach in the future, either through agreement with the industry, or individually with Duke.

In response to Item (2), the NUREG/CR-6260 locations applicable to McGuire and Catawba are identified below in Table 4.3-5, "Newer Vintage Westinghouse Plant Locations Identified in NUREG/CR-6260." The current design basis usage factors for each of these locations is less than one. The details of the design, including stress and fatigue analysis results, are contained in engineering documents maintained onsite and available for inspection

Table 4.3-5
Newer Vintage Westinghouse Plant Locations Identified in NUREG/CR 6260

Reactor Vessel	At lower head to shell juncture
	Inlet Nozzle
	Outlet Nozzle
Surge Line	Hot Leg Nozzle
Charging Nozzle	Nozzle
Safety Injection Nozzle	Nozzle
Residual Heat Removal Line	Inlet Transition

In response to Item (3), Duke has stated that it may wish to use flaw tolerance and inspection procedures to validate a plant component for cyclic duty. Duke recognizes that the NRC staff has not endorsed a procedure on a generic basis which allows for flaw tolerance evaluations combined with ASME Section XI inspections in lieu of meeting the fatigue usage criteria.

Duke agrees not to use flaw tolerance/inspection procedures unless such procedures have been accepted by the NRC. At the appropriate time during the period of extended operation, if no procedure is as yet agreed to between the NRC and the industry or with Duke, Duke agrees to obtain concurrence from the NRC on the technical processes involved in such procedures on a case by case basis. As stated in the Application, Duke may choose to exercise a different course of action should the NRC approve a less restrictive approach in the future, either through agreement with the industry, or individually with Duke.

In response to Item (4), Duke recognizes the ongoing discussions between the industry and the NRC staff on the use of a Z factor with a value greater than 1.0 in the equations associated with fatigue reactor water effects. These discussions will likely result in clarifying the entire fatigue reactor water environmental effects issue sometime in the future. Since the specific issue of fatigue reactor water effects is only applicable to the period of extended operation (earliest start date for the extended period of operation for McGuire and Catawba is 2021 for McGuire 1), Duke anticipates that the equations specified as a part of the Application may be revised to better reflect the then current best practice. As stated in the Application, Duke may choose to exercise a different course of action should the NRC approve a less restrictive approach in the future, either through agreement with the industry, or individually with Duke. With this in mind, the Duke procedure specified in Application Section 4.3.1.2 will be revised to set Z factor equal to 1.0 unless a different value is warranted by then acceptable practice.

RAI 4.3-6

The LRA does not address the issue of underclad cracks. The Westinghouse Owners Group (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. This report describes the fracture mechanics analysis that evaluates the impact of 60 years of operation on reactor vessel underclad crack growth and reactor vessel integrity. However, in a letter dated April 12, 2001, the staff identified area where additional information is needed to complete its review of WCAP-15338. The WOG response to the RAI is contained in letters dated June 15, 2001, and July 31, 2001. The WOG response indicates that the pressurized thermal shock portion of the analysis applies to three loop Westinghouse plants. WCAP-15338 indicates that underclad cracks are confined to forging materials, SA 508 Class 2 and 3. 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. Provide the following information:

1. Identify any reactor vessel components that were fabricated from SA 508 Class 2 or 3 forgings.

2. Indicate whether any of the SA 508 Class 2 or 3 forgings identified above are susceptible to underclad cracking.

3. Indicate whether any of the SA 508 Class 2 or 3 forgings are subject to neutron embrittlement (i.e., subject to a neutron fluence greater than or equal to 10^{17} n/cm^2 [E>1MeV]).

4. If any forgings are susceptible to underclad cracking, identify the basis for concluding that the cracks will not result in loss of reactor vessel integrity during the period of extended operation. The assessment should consider the impact of fatigue and neutron embrittlement on the underclad cracks.

Response to RAI 4.3-6

The Application does not address the issue of underclad cracks because underclad cracking was not identified as a time-limited aging analyses for McGuire or Catawba. In order to be considered as time-limited aging analyses, calculations or analyses must meet the six criteria contained §54.3. For McGuire and Catawba, no calculations or analyses were identified that considered the issue of underclad cracks for any period of time. All six of these criteria have not been met. Therefore, this issue is not a time-limited aging analysis for either McGuire or Catawba.

Regarding Item (1) in RAI 4.3-6, for McGuire Unit 2 and Catawba Unit 1, the vessel flange, upper shell course, nozzles, intermediate shell coarse, lower shell coarse, and the top head ring and flange (parts of the closure head assembly) were fabricated from SA 508 Class 2 forgings. The McGuire Unit 1 and Catawba Unit 2 closure head flange, vessel flange and the reactor vessel inlet and outlet nozzles are fabricated from SA 508 Class 2 forgings.

Regarding Item (2) in RAI 4.3-6, manufacturing records for the forgings that describe the method of cladding application have not been located. Therefore, a conservative assumption has been made that the forgings are potentially susceptible to underclad cracking.

For Item (3), the SA 508 Class 2 forgings that are subject to neutron fluence greater than or equal to 10^{17} neutrons/cm^2 (E > 1 MeV) are:

- Intermediate shell and the lower shell for McGuire Unit 2 and Catawba Unit 1
- Inlet and outlet nozzles for McGuire Unit 2 and Catawba Unit 1 [Estimated fluence is below 3 x 10^{17} neutrons/cm^2 (E > 1 MeV)]
- Inlet nozzles for McGuire Unit 1 and Catawba Unit 2 [Estimated fluence is below 3 x 10^{17} neutrons/cm^2 (E > 1 MeV)]

For Item (4), underclad cracking typically occurs only in the grain-coarsened region of the base metal heat-affected zone at the weld bead overlap. The subsurface location and the size of these cracks make them difficult to detect using standard non-destructive examination methods. Detection normally requires destructive examination through removal of the cladding to the weld fusion line and examination of the underlying base metal. In May 1973, the NRC issued Regulatory Guide 1.43 to address underclad cracking. Regulatory Guide 1.43 includes recommended controls that may be used to limit the occurrence of underclad cracking in low-alloy steel Class 1 components. As identified in McGuire UFSAR Table 1-4 and Catawba UFSAR Section 1.7, Regulatory Guide 1.43 was adopted for the fabrication of McGuire and Catawba Class 1 components and it is unlikely that these components fabricated from SA 508 Class 2 material contain the subject fabrication flaws.

In order to provide additional assurance that underclad cracking is not a concern during the period of extended operation, a bounding analysis for all Westinghouse plants is contained in WCAP-15338, "A Review of Cracking Associated with Weld Deposited Cladding in Operating PWR Plants," that has been previously prepared and submitted to the NRC. In its safety evaluation report dated October 15, 2001, the NRC found WCAP-15338 acceptable for referencing in license renewal applications. WCAP-15338 provides flaw evaluations based on Section XI of the American Society of Mechanical Engineers Code to justify that the

Westinghouse reactor pressure vessels with underclad cracks are acceptable for operation for 60 years.

The staff safety evaluation report for WCAP-15338 includes two renewal applicant action items that must be addressed. Renewal Applicant Action Item (1) requires the license renewal applicant to verify that its plant is bounded by the WCAP-15338 report. On January 22, 2002 Westinghouse submitted a letter to the Document Control Desk stating that, "The 3-loop RPV evaluation presented in the report is intended to be a bounding evaluation for all Westinghouse plant sizes, including both 2-loop and 4-loop RPVs." Duke confirms that the McGuire and Catawba vessels are bounded by WCAP-15338. The analysis presented in WCAP-15338 provides additional assurance that underclad cracks will not result in a loss of reactor vessel integrity during the period of extended operation for both McGuire and Catawba.

Renewal Applicant Action Item (2) requires license renewal applicants referencing WCAP-15338 to ensure that the evaluation of the TLAA is summarily described in the FSAR Supplement. For the reasons discussed above, the issue of underclad cracks is not a time-limited aging analysis for either McGuire or Catawba. Therefore, no summary description is required to be included in the UFSAR Supplements.

RAI 4.3-7

Section 4.3.2 of the LRA addresses ASME Section III, Class 2 and 3 piping fatigue. The LRA indicates that two locations at McGuire and Catawba could reach the 7,000 cycle limit during the period of extended operation. Identify these locations and indicate how the number of expected cycles was determined. Also describe the re-evaluation that was performed to demonstrate these locations will be acceptable for the period of extended operation.

Response to RAI 4.3-7

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. A comparison of actual operating experience to the design thermal cycle assumptions, including a projection of assumed future cycles, was performed to determine the number of expected thermal cycles for 60 years of operation.

For McGuire, a location in the Diesel Generator Starting Air (VG) starting air compressor discharge piping was found to experience a thermal cycle every time the compressor cycles. The compressor cycles frequently. A projected number of cycles was extrapolated for 60 years of operation and was found to exceed 7000 thermal cycles. A conservative stress range reduction factor was applied to the stress calculation and the results were found to be within Code compliance. The second McGuire location in a portion of drain piping of the Main Steam (SM) System was found to experience significant thermal cycling each unit startup. Plant computer data was retrieved for the past 5 years and extrapolated for 60 years of operation and found to exceed 7000 thermal cycles. A conservative stress range reduction factor was applied to the stress calculation and the results were found to be within Code compliance.

For Catawba, the same Diesel Generator Starting Air (VG) starting air compressor discharge piping was found to be susceptible to thermal cycling. A conservative stress range reduction factor was applied to the stress calculation and the results were found to be within Code compliance. Additionally, the pressurizer liquid sample piping is used to sample boron frequently and was found susceptible to thermal cycling. A projected number of cycles was extrapolated for 60 years of operation for each location and was found to exceed 7000 thermal cycles. A conservative stress range reduction factor was applied to the stress calculation and the results were found to be within Code compliance.

4.7.1 Reactor Coolant Pump Flywheel Fatigue

RAI 4.7.1-1

Section 4.7.1 of the LRA discusses the analysis related to a 60-year fatigue life for the reactor coolant pump fly wheel. Provide a summary of the existing design basis analysis to enable the staff to evaluate the validity of fatigue life for the extended period of operation.

Response to RAI 4.7.1-1

The analysis related to a 60-year fatigue life for the reactor coolant pump flywheel is discussed on page 4.7-1 of the Application. As provided in the reference to Section 4.7.1, the analysis was provided to the staff in WCAP-14535A, *Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination*, November 1996. In the staff's safety evaluation for License Amendment No. 190 and No. 171, dated December 21, 1999, the staff concluded that the requirements had been met to show that WCAP-14535A was applicable to McGuire Nuclear Station. A similar conclusion was reached for Catawba Nuclear Station in the safety evaluation for License Amendments No. 182 and No. 174, dated December 21, 1999.

B.3.1 Alloy 600 Review

RAI B.3.1-1
Confirm that the following aspects of your Alloy 600 Review are valid:

1. The Alloy 600 Review 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.

2. The program attributes are normally provided in the application for programs that are listed in the LRA as aging management programs. Since the Alloy 600 Review is simply a review program, the program attributes for the review are not necessary.

Response to RAI B.3.1-1
The staff description of the *Alloy 600 Program* provided in RAI B.3.1-1 is correct. As stated in Appendix B.3.1 of the Application, the purpose of the *Alloy 600 Aging Management Review* is 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 Head Penetration Program* (Appendix B.3.9), the *Reactor Vessel Internals Inspection* (Appendix B.3.27), and the *Steam Generator Integrity Program* (Appendix B.3.31). 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 the review.

B.3.5 Bottom-Mounted Instrumentation Thimble Tube Inspection Program

RAI B.3.5-1

For Catawba Unit 1, the applicant had performed thimble inspections in 1988, 1993, and 1999; for Catawba Unit 2, the applicant had performed inspections in 1989, 1990, and 1993. No significant changes in wear rates were detected in both units, and no tubes are capped in Unit 1; however, two tubes are capped in Unit 2 due to wear concerns. The LRA indicates that no further testing will be required until 2008 for Unit 1, and 2007 for Unit 2. Based on the description in the LRA, it appears that tube wear condition is more severe in Unit 2 than Unit 1. Explain why the projected next testing for Unit 2 (in 2007) is fourteen years after the previous testing (in 1993) in comparison with nine years (1999 to 2008) in Unit 1, and provide details of wear projection calculations of both units. Are the thimble tubes designed similarly (such as same tube wall thickness) for both units? Or is there a modified design that is used in Unit 2? What is the allowable number of thimbles that may be capped? Will the allowable capped number be exceeded for extended plant operation of 20 more years? Should this happen, what corrective actions will be taken?

Response to RAI B.3.5-1

The expanded test interval for both Catawba Unit 1 and 2 bottom-mounted thimble tubes is warranted based on historical data trends. However, since the Application was submitted, the plans for future testing presented in Section B.3.5 of the Application have been updated. The next testing for Catawba Unit 2 is scheduled to be performed in 2004 and not 2007 as previously stated in the Application. The next scheduled testing for the thimble tubes in Catawba Unit 1 remains in 2008.

Thimble tube wear is conservatively assumed to occur any time the reactor coolant pumps are operating as tube wear is caused by flow induced vibration. Because thimble tube wall loss is a function of operating time, a mathematical relationship has been established between the current tube wall condition and a projected, future condition in order to establish inspection time intervals. Each inspected thimble tube has its own set of data that characterizes its current condition and that data is used to extrapolate a future time interval for re-inspection. The calculations associated with thimble tube wear and the establishment of inspection intervals are contained in engineering documents maintained on site and available for inspection.

The design of the bottom-mounted thimble tubes is the same for both Catawba Unit 1 and 2. The maximum number of thimble tubes that can be capped on a unit is 14. As defined in Catawba UFSAR Chapter 16.7-7, "Movable Core Detectors," a minimum of 75% or 44 of 58 total tubes are required to be in service in order to properly perform core power distribution surveillance. Given the current state of the thimble tubes and the current rate of wear of the tubes, it is not anticipated that more than 14 tubes per unit would require removal from service due to wear by the conclusion of the period of extended operation. While not directly related to aging, another challenge to the life of the individual tubes is physical damage due to handling and exposure during refueling outages. In the event that the total number of tubes removed from service by the corrective action steps of the *Bottom-Mounted Instrumentation Thimble Tube Inspection Program* begins to approach the limit where required surveillances could not be adequately conducted, then the plant modification process would instigate wholesale replacement of the thimble tubes.

RAI B.3.5-2

For McGuire, the LRA indicates that the Unit 1 thimble inspections had been performed in 1988 and 2001 with 10 tubes showing detectable wall loss. Two tubes were capped due to other types of damage. The Unit 2 inspections had been performed in 1989 and 1993 with eight tubes showing wear. The future inspections are planned in 2008 for Unit 1 and in 2005 for Unit 2. Clarify the type of "other damage" in the two capped tubes at Unit 1, and provide more details of tube wear projection calculations at both units. Are tubes with modified design being used in either units?

Response to RAI B.3.5-2

The other types of damage that caused thimble tubes to be capped were (1) a bent thimble and (2) an obstruction from a tube that had been inserted for flushing during a previous outage and not removed. The issues described above are not related to aging. The tube wear projection calculations are performed using the same methodology as described in Response to RAI B.3.5-1. Tubes with a modified design are not being used in either unit.

RAI B.3.5-3
Since a thimble tube failure will result in leakage of reactor coolant, verify whether a leaking thimble tube can be isolated, and describe the corrective actions to be taken under such circumstances.

Response to RAI B.3.5-3
Each incore thimble has a manual isolation valve installed just above the high pressure fitting at the seal table. These manual valves could be used to initially isolate any leakage through a thimble. Following plant shutdown and depressurization, the leaking thimble tube would be capped.

RAI B.3.5-4

The design of thimble tubes has evolved with respect to their thickness, gap size between tube wall and guide tube, and isolation techniques since the issuance of Inspection and Enforcement (IE) Bulletin 88-09. In order to demonstrate that continued implementation of the existing thimble tube inspection program is capable of monitoring tube wall thinning prior to loss of component intended function during the extended plant operation for 20 more years, supplement the summary of industry experience regarding the performance of bottom-mounted instrumentation thimble tubes, specifically with the same design, if any, as the tubes used in McGuire and Catawba.

Response to RAI B.3.5-4

Searches of industry operating experience, LERs, and knowledge gained by plant personnel through interaction with their peers have provided no indication that the inspection programs implemented in response to Inspection and Enforcement Bulletin 88-09 are inadequate. Currently, Duke-specific experience indicates that continued implementation of the existing thimble tube inspection program is capable of monitoring tube wall thinning and taking corrective actions prior to loss of component intended function.

B.3.9 Control Rod Drive Mechanism (CRDM) Nozzle and Other Vessel Closure Penetrations Inspection Program

RAI B.3.9-1

The CRDM Nozzle and Other Vessel Closure Penetration Inspection Program, described in Section B.3.9 of Appendix B the LRA, is designed to manage cracking in the Alloy 600 vessel head penetration (VHP) nozzles of the McGuire and Catawba units. In Section B.3.9 of the LRA, the applicant did not specify whether it would continue to be a participant in the NEI program for managing primary water stress corrosion cracking (PWSCC) type aging in Alloy 600 VHP nozzles of U.S. pressurized water reactor (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:

1. Discuss how the recent circumferential cracking discussed in NRC Bulletin 2001-01 will impact your management program for the McGuire and Catawba CRDM penetration nozzles and other vessel head penetration nozzles.

2. Discuss what additional activities you will be participating in, if any, that will be implemented as part of this program.

Response to RAI B.3.9-1

The recent circumferential cracking issue discussed in NRC Bulletin 2001-01 will not affect the *Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program* as proposed in the Application. Since the circumferential cracking was identified at Oconee Nuclear Station in November 2000, Duke has been aware of the concern prior to the NRC issuance of NRC Bulletin 2001-01. 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 & 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 Owner's Group.

Duke's response to NRC Bulletin 2001-01 dated August 31, 2001 states that both McGuire and Catawba Nuclear Stations are included in the grouping of plants with the lowest susceptibility to PWSCC and no additional activities are currently planned to be added to the *Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program* described in B.3.9 of the Application.

As permitted by §54.17(e), Duke incorporates by reference the McGuire and Catawba information contained in the following two transmittals:

(1) Alex Marion (NEI) letter dated March 28, 2002 to Dr. Brian Sheron (NRC), *Industry Survey Questions on PWR Head Inspections,* Project 689.
(2) K.S. Canady (Duke) letter dated April 1, 2002 to Document Control Desk (NRC), *Response to NRC Bulletin 2002-01: Reactor Pressure Vessel head Degradation and Reactor Coolant Pressure Boundary Integrity,* Docket Nos. 50- 369, -370, -413, and -414.

B.3.26 Reactor Vessel Integrity Program

RAIs B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4.

Note: The four NRC Staff 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 vessels each contain the following two imbedded 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?*

These two questions will be answered generically prior to addressing the plant specific issues raised in RAIs B B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4.

For fluence values, the following references should be used for each reactor as follows:

- McGuire Unit 1, WCAP-15253, "Duke Power Company Reactor cavity Neutron Measurement Program for William B. McGuire Unit 1 Cycle 12," Submitted by Duke letter dated March 19, 2002.

- McGuire Unit 2, WCAP-15334, "Duke Power Company Reactor cavity Neutron Measurement Program for William B. McGuire Unit 2 Cycle 12," Submitted by Duke letter dated March 19, 2002.

- Catawba Unit 1, WCAP-15117, "Analysis of Capsule V and Dosimeters from Capsules U and X from the Duke Power Company Catawba Unit 1 Reactor Vessel Radiation Surveillance Program," Submitted by Duke letter dated December 16, 1998.

- Catawba Unit 2, WCAP-15243, "Analysis of Capsule V and Capsule Y Dosimeters from the Duke Energy Catawba Unit 2 Reactor Vessel radiation Surveillance Program," Submitted by Duke letter dated September 13, 1999.

In general, the following three major factors govern the projection of end-of-license fast neutron exposure of Light Water Reactor (LWR) pressure vessels:

1. The actual plant specific fuel cycle designs and system operating temperatures and pressures implemented between initial plant startup and the time of the projection to end-of-license.

2. The assumed future fuel management strategy and system operating temperatures and pressures for the period between the time of projection and the end-of-license date.

3. The analytical methods used to compute the neutron exposure of the pressure vessel.

The first, and most influential, factor influencing changes in the calculated end-of-license fluence at the pressure vessel wall is the trend towards low leakage fuel management over the operating lifetime of the respective reactors. A second, though less influential, factor is the continuous improvement in fluence evaluation methodology over the last twenty years.

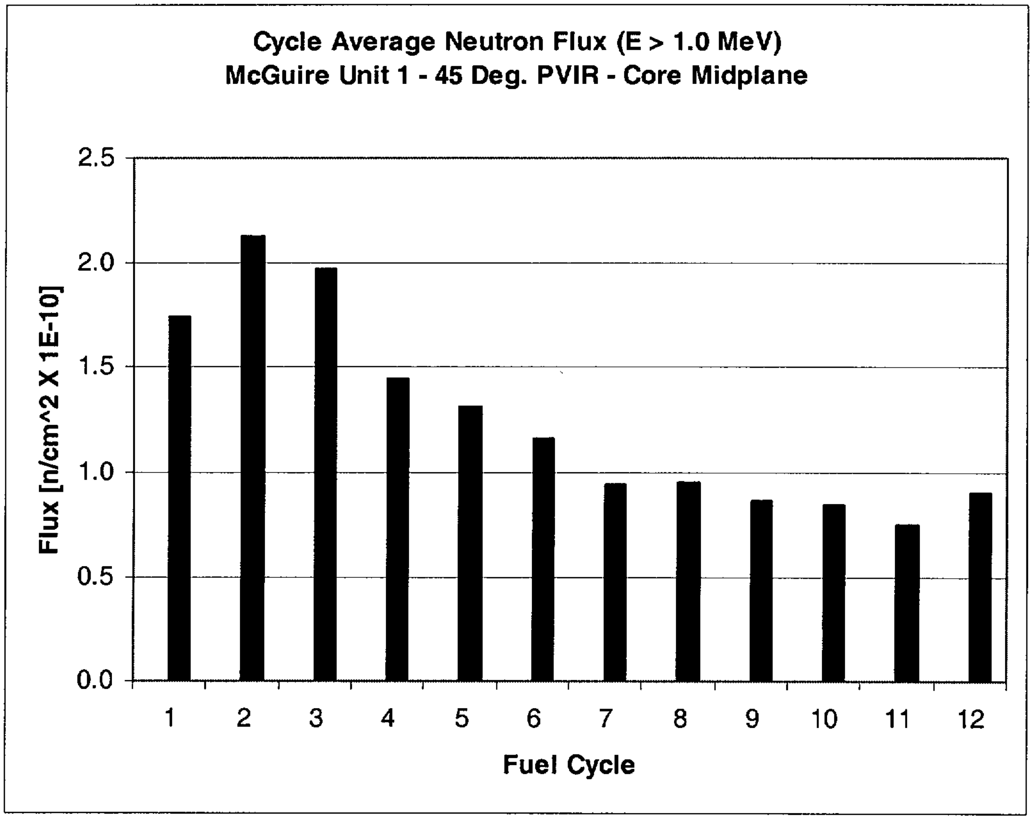
In terms of fuel management, the operating histories of the McGuire and Catawba reactors can be divided into the following three periods:

1 - An early operational period characterized by the use of out-in fuel loading patterns that resulted in the placement of unburned fuel assemblies along the periphery of the core.

2 - A transitional period during which partially burned fuel assemblies began to be placed at selected locations along the core periphery.

3 - A later operational period during which low leakage fuel management became fully established with the placement of highly burned fuel assemblies at most, if not all, of the peripheral fuel assembly locations.

Since the neutron exposure of the pressure vessel wall is dominated by the neutron source in the peripheral fuel assemblies (approximately 90% - 95% of the vessel fluence is due to neutrons produced in the assemblies adjacent to the baffle plates), the implementation of low leakage fuel management has a profound effect on the magnitude, and in some cases, the location of the projected maximum vessel fluence. The following figure illustrates the effect of changing fuel management on the calculated neutron flux (E > 1.0 MeV) at the core midplane elevation along the 45° azimuth at McGuire Unit 1.



The data in this figure show a reduction of approximately a factor of two in the neutron flux at the pressure vessel wall due to the introduction of low leakage fuel management. Similar behavior is characteristic of the neutron flux profiles calculated for McGuire Unit 2, Catawba Unit 1, and Catawba Unit 2.

Fluence projections for future operating periods are generally performed prior to initial plant startup as well as coincident with each surveillance capsule withdrawal. When new projections are made, the plant specific fluence based on actual core loading patterns implemented up to the time of capsule withdrawal is determined and projections from that point to the end-of-license are made based on an assumed mode of future operation.

Prior to plant startup and in the early stages of plant life, when little historical fuel management data are available, fluence projections are made using a conservative design basis or reference core power distribution. As more operational history becomes available and the future fuel management strategies become clear, projections are updated to account for the anticipated future operational mode. As an example, the past and current projections for the McGuire Unit 1 reactor pressure vessel were based on the following:

Report	Report Completion	Cycles Included in Plant Specific Evaluation	Basis for Future Fluence Projections
WCAP-10786	End of Cycle 1	1	Design Basis
WCAP-12354	End of Cycle 5	1 through 5	Avg. of Cycles 1-5
WCAP-13949	End of Cycle 8	1 through 8	Avg. of Cycles 1-8
WCAP-14993	End of Cycle 11	1 through 11	Avg. of Cycles 9-11
WCAP-15253	End of Cycle 12	1 through 12	Avg. of Cycles 9-12

As can be seen from this tabulation, the basis for fluence projections for future operation at McGuire Unit 1 has evolved from the use of design basis information, through a transitional period accounting for both out-in and in-out fuel loading patterns, and finally to the use of fully established low leakage loading patterns. In addition, at each re-analysis a larger portion of the total fluence assessment is based on the plant specific evaluation of past fuel cycle loading patterns.

In addition to the trend towards the implementation of low leakage fuel management, a methods improvement based on the use of neutron transport cross-sections derived from the ENDF/B-VI rather than ENDF/B-IV data files has taken place over the last 8 years. This improvement in methods results in an increase in the calculated vessel fluence of 10%-20% depending on the amount of steel located between the reactor core and the pressure vessel wall. The use of low leakage fuel management, however, more than offsets this increase in fluence caused by the methods upgrade. As can be seen from the above figure, the incident neutron flux at the vessel wall is reduced by approximately a factor of two relative to that calculated for out-in loading patterns. The combination of a fluence decrease due to low leakage fuel management and an offsetting increase due to methods improvements generally results in a net reduction in projected end-of-license fluence relative to earlier predictions based on design basis or out-in loading pattern assumptions.

Plant specific core loading patterns can also impact the azimuthal distribution of neutron flux incident on the pressure vessel. The flux at a given azimuthal location is dominated by a relatively small subset of fuel assemblies located on the core periphery. Since low leakage loading patterns do not necessarily result in a uniform power reduction around the periphery of the core, the relative azimuthal distribution of neutron flux can change from cycle to cycle. In turn, the integrated effect of these cycle specific core power distributions can result in a change over time in the location of the maximum neutron exposure of the pressure vessel. The changes in the location of the maximum exposure of the pressure vessel are accounted for in the plant specific evaluations that are carried out over the course of the Reactor Vessel Materials Surveillance Program.

An example of this behavior for Catawba Unit 2 is illustrated in Table 6-2 of WCAP-15243. The pertinent portion of that table is reproduced here as follows:

Fuel Cycle	Calculated Neutron Flux (E > 1.0 MeV) [n/cm^2-s]		
	15 Degrees	30 Degrees	45 Degrees
1	2.23E10	2.65E10	**2.88E10**
2	1.93E10	**2.04E10**	1.98E10
3	2.03E10	2.13E10	**2.21E10**
4	**1.92E10**	1.87E10	1.43E10
5	**1.90E10**	1.81E10	1.43E10
6	1.91E10	**2.03E10**	1.85E10
7	1.77E10	**1.94E10**	1.85E10
8	1.72E10	**1.80E10**	1.58E10
9	1.49E10	**1.75E10**	1.60E10

In the above tabulation, the maximum neutron flux incident on the pressure vessel for each individual fuel cycle is given in **boldface** type. The movement in the location of the maximum flux from cycle to cycle is clearly evident.

The integrated effect of the changing fuel management on reactor pressure vessel fluence is summarized as follows:

End of Fuel Cycle	Cumulative Neutron Fluence (E > 1.0 MeV) [n/cm^2]		
	15 Degrees	30 Degrees	45 Degrees
1	6.05E17	7.19E17	**7.82E17**
2	1.08E18	1.22E18	**1.27E18**
3	1.66E18	1.83E18	**1.90E18**
4	2.24E18	**2.39E18**	2.33E18
5	2.85E18	**2.97E18**	2.79E18
6	3.47E18	**3.64E18**	3.40E18
7	4.13E18	**4.36E18**	4.08E18
8	4.78E18	**5.04E18**	4.68E18
9	5.40E18	**5.76E18**	5.34E18

Again, in the above tabulation, the maximum neutron exposure of the pressure vessel is highlighted in **boldface** type. The shift in the maximum from the 45° to the 30° azimuthal location is clearly evident as low leakage fuel management is implemented.

The comparisons listed in the two preceding tables were based on the BUGLE-96 calculations provided in WCAP-15243. The methods change from ENDF/B-IV to ENDF/B-VI neutron transport cross-sections also resulted in changes in the calculated relative azimuthal distributions at the reactor vessel wall. This change was due to the fact that the reactor internals designs for the McGuire and Catawba units includes azimuthally segmented neutron pads mounted on the core barrel. The effect of the ENDF/B-VI cross-sections was to increase the calculated neutron flux at locations behind the neutron pads to a greater degree than at azimuthal locations away from the pads, thus changing the relative azimuthal flux distribution. This effect was a one-time, historical change that is fully accounted for in the latest fluence evaluations for the McGuire and Catawba units.

The following discussion addresses the unit specific issues relative to RAIs B.3.26-1, B.3.26-2, B.3.26-3, and B.3.26-4.

RAI B.3.26-1

For Catawba Unit 1: In Table B.3.26-2, the staff notes that the 32 EFPY ID vessel fluence is 2.334 [in terms of 10^{19} n/cm^2]. However, the projected value in WCAP-11527, Table 6-11 is 3.17 [no azimuth is specified], in WCAP-13720 Table 6-17, at 25° is 2.52 and in WCAP-15117, Table 6-14 for 34 EFPY's is 1.98 at 30°. The updating of the older values should have resulted in higher values. Please explain the apparent discrepancies [projected low leakage loadings] and the physics of the updating which justifies the differences. Why does the maximum occur at slightly different azimuths?

Response to RAI B.3.26-1

The neutron fluence values listed in Table B.3.26-2 provide the actual or projected neutron exposure of the reactor vessel materials surveillance capsules irradiated in Catawba Unit 1. Since surveillance Capsules Z, Y, X, U, and V have been withdrawn from the reactor, the fluence values listed in Table B.3.26-2 represent the calculated plant specific neutron exposure accrued by each capsule up to the time of withdrawal. For Capsule W, which still remains in the reactor, the fluence value listed represents the projected neutron exposure at the scheduled withdrawal date (End of cycle 14). The fluence values provided in Table B.3.26-2 do not represent the plant specific exposure of the Catawba Unit 1 pressure vessel wall.

The following table provides a comparison of the capsule fluence values provided in the series of reports that summarize the Catawba Unit 1 Reactor Vessel Materials Surveillance Program:

	Reported Fluence (E > 1.0 MeV) [n/cm^2]		
Capsule	**WCAP-11527 (1987)**	**WCAP-13720 (1993)**	**WCAP-15117 (1998)**
Z	3.08E18	3.43E18	2.99E18
Y	-	1.35E19	1.32E19
X	-	-	2.44E19
U	-	-	2.44E19
V	-	-	2.33E19

The changes in the assigned capsule fluences are due in part to a continuous methodology improvement over the last 15 years as well as to a change in NRC staff philosophy relative to the use of calculated rather than measured or adjusted fluence in vessel integrity assessments.

The methodologies reflected in each of these surveillance capsule evaluation reports are summarized as follows:

WCAP	Basis for Capsule Fluence	Transport Calculation Methodology	Transport X-Sec Basis	Dosimetry Evaluation Methodology	Dosimetry X-Sec Basis
11527	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Spectrum Averaged X-Sec Based On S_n Calc.	ENDF/B-IV
13720	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
15117	Calculation	S_n Transport	ENDF/B-VI (BUGLE-93)	Least Squares	ENDF/B-VI (SNLRML)

The capsule fluence values reported in WCAP-15117 are based on calculations using neutron transport cross-sections derived from the ENDF/B-VI data files rather than on the capsule dosimetry measurements. As such, these assigned fluences are based on a methodology that meets the requirements of Regulatory Guide 1.190 and are intended to supersede the neutron exposure values provided in the older reports.

In addition to the calculated surveillance capsule fluence levels reported in Table 6-12 of WCAP-15117, the best estimate maximum neutron exposure of the pressure vessel wall projected to 22, 34 and 54 effective full power years is given in Table 6-14. These best estimate values can be converted to calculated maximum vessel exposures by dividing the best estimate value by the average BE/C bias factor of 0.954 noted on Table 6-12 of WCAP-15117. The resultant projected fluence values based on calculation alone are 1.30E19 n/cm^2, 1.98E19 n/cm^2 and 3.11E19 n/cm^2 for 22, 34, and 54 EFPY, respectively. Using linear interpolation, a corresponding maximum fluence value of 1.87E19 n/cm^2 is calculated for 32 EFPY of operation.

The footnotes accompanying Table B.3.26-2 of the Application are intended to indicate which of the Catawba Unit 1 surveillance capsule exposures most closely match the corresponding projected vessel fluence at the irradiation times stated. For example, footnote (b) indicates that the actual Capsule V exposure of 2.33E19 n/cm^2 is the closest available data set to the projected 32 EFPY vessel exposure of 1.87E19 n/cm^2. Likewise, footnote (d) indicates that the projected fluence of 3.0E19 n/cm^2 at the EOC 14 withdrawal date of Capsule W will provide a data set that closely matches the projected 54 EFPY vessel exposure of 3.11E19 n/cm^2.

RAI B.3.26-2

For Catawba Unit 2: Same as in Catawba Unit 1 (see RAI B.3.26.2-3) regarding reported values for 32 EFPY's in WCAP-11941 and WCAP-13875 vs the submittal Table B.3.26-2. In addition, WCAP-13875 does not report calculated values. (Note: in WCAP-11941, Table 6-13 values at 25°, 30°, and 45° is there a typo? Max should be at 25°). Please explain the apparent discrepancies [projected low leakage loadings] and the physics of the updating which justifies the differences. Why does the maximum occur at slightly different azimuths?

Response to RAI B.3.26-2

The neutron fluence values listed in Table B.3.26-2 of Appendix B of the Application provide the actual or projected neutron exposure of the reactor vessel materials surveillance capsules irradiated in Catawba Unit 2. Since surveillance Capsules Z, X, V, and Y have been withdrawn from the reactor, the fluence values listed in Table B.3.26-2-3 of the Application represent the calculated plant specific neutron exposure accrued by each capsule up to the time of withdrawal. For Capsule W, which still remains in the reactor, the fluence value listed represents the projected neutron exposure at the scheduled withdrawal date (End of cycle 14). Capsule U is currently designated as a standby capsule with no scheduled withdrawal date. Therefore, no projected fluence is reported. The fluence values provided in Table B.3.26-2 do not represent the plant specific exposure of the Catawba Unit 2 pressure vessel wall.

The following table provides a comparison of the capsule fluence values provided in the series of reports that summarize the Catawba Unit 2 Reactor Vessel Materials Surveillance Program:

	Reported Fluence (E > 1.0 MeV) [n/cm^2]		
Capsule	**WCAP-11941 (1988)**	**WCAP-13875 (1994)**	**WCAP-15243 (1999)**
Z	3.36E18	3.44E18	3.23E18
X	-	1.22E19	1.23E19
V	-	-	2.38E19
Y	-	-	2.49E19

The changes in the assigned capsule fluences are due in part to a continuous methodology improvement over the last 18 years as well as to a change in NRC staff philosophy relative to the use of calculated rather than measured or adjusted fluence in vessel integrity assessments.

The methodologies reflected in each of these surveillance capsule evaluation reports are summarized as follows:

WCAP	Basis for Capsule Fluence	Transport Calculation Methodology	Transport X-Sec Basis	Dosimetry Evaluation Methodology	Dosimetry X-Sec Basis
11941	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
13875	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
15243	Calculation	S_n Transport	ENDF/B-VI (BUGLE-96)	Least Squares	ENDF/B-VI (SNLRML)

The capsule fluence values reported in WCAP-15243 are based on calculations using neutron transport cross-sections derived from the ENDF/B-VI data files rather than on the capsule dosimetry measurements. As such, these assigned fluences are based on a methodology that meets the requirements of Regulatory Guide 1.190 and are intended to supersede the neutron exposure values provided in the older reports.

In addition to the calculated surveillance capsule fluence levels reported in Table 6-12 of WCAP-15243, the calculated maximum neutron exposure of the pressure vessel wall projected to 22, 34 and 54 effective full power years is given in Table 6-13. These projected fluence values are 1.31E19 n/cm^2, 2.01E19 n/cm^2 and 3.16E19 n/cm^2, respectively. Using linear interpolation, a corresponding maximum fluence value of 1.89E19 n/cm^2 for a 32 EFPY irradiation period.

The footnotes accompanying Table B.3.26-2 of the Application are intended to indicate which of the Catawba Unit 2 surveillance capsule exposures most closely match the corresponding projected vessel fluence at the irradiation times stated. For example, footnote (b) indicates that the actual Capsule V exposure of 2.38E19 n/cm^2 is the closest available data set to the projected 32 EFPY vessel exposure of 1.89E19 n/cm^2. Likewise, footnote (d) indicates that the projected fluence of 3.0E19 n/cm^2 at the EOC 14 withdrawal date of Capsule W will provide a data set that closely matches the projected 54 EFPY vessel exposure of 3.16E19 n/cm^2.

RAI B.3.26-3
For McGuire Unit 1: In Table B.3.26-1 of the submittal, a 54 EFPY fluence is reported and referenced to WCAP-14993 which does not include 54 EFPY values. Please explain. The 1/4T value for 32 EFPY's reported in WCAP-12354 is significantly different than the value reported in the submittal and referenced to WCAP-12354. Please explain. The value reported in WCAP-10786 for 32 EFPY's and the corresponding value reported in the submittal and referenced to WCAP-13949 are significantly different. Please explain. A fluence value is reported in Table B.3.26-1 of the submittal for 54 EFPY of the vessel and referenced to WCAP-14993 which does not report values at 54 EFPY's. In addition, the value reported for 50.3 EFPY is almost the same. Please explain.

Response to RAI B.3.26-3
The neutron fluence values listed in Table B.3.26-1 of the Application provide the actual or projected neutron exposure of the reactor vessel materials surveillance capsules irradiated in McGuire Unit 1. Since surveillance Capsules U, X, Y, Z, and V have been withdrawn from the reactor, the fluence values listed in Table B.3.26-2-1 of the Application represent the calculated plant specific neutron exposure accrued by each capsule up to the time of withdrawal. For Capsule W, which still remains in the reactor, the fluence value listed represents the projected neutron exposure at the scheduled withdrawal date (End of cycle 16). The fluence values provided in Table B.3.26-1 do not represent the plant specific exposure of the McGuire Unit 1 pressure vessel wall.

The following table provides a comparison of the capsule fluence values provided in the series of reports that summarize the McGuire Unit 1 Reactor Vessel Materials Surveillance Program:

	Reported Fluence (E > 1.0 MeV) [n/cm^2]				
Capsule	WCAP 10786 (1985)	WCAP 12354 (1989)	WCAP 13949 (1994)	WCAP 14993 (1998)	WCAP 15253 (1999)
U	4.13E18	-	4.71E18	4.03E18	4.05E18
X	-	1.38E19	1.41E19	1.49E19	1.50E19
V	-	-	2.18E19	2.07E19	2.08E19
Z	-	-	2.29E19	2.37E19	2.38E19
Y	-	-	-	2.85E19	2.86E19

The changes in the assigned capsule fluences are due in part to a continuous methodology improvement over the last 18 years as well as to a change in NRC staff philosophy relative to the use of calculated rather than measured or adjusted fluence in vessel integrity assessments.

The methodologies reflected in each of these surveillance capsule evaluation reports are summarized as follows:

WCAP	Basis for Capsule Fluence	Transport Calculation Methodology	Transport X-Sec Basis	Dosimetry Evaluation Methodology	Dosimetry X-Sec Basis
10786	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Spectrum Averaged X-Sec Based On S_n Calc.	ENDF/B-IV
12354	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
13949	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
14993	Calculation	S_n Transport	ENDF/B-VI (BUGLE-93)	Least Squares	ENDF/B-VI (SNLRML)
15253	Calculation	S_n Transport	ENDF/B-VI (BUGLE-93)	Least Squares	ENDF/B-VI (SNLRML)

The capsule fluence values reported in WCAP-15253 are based on calculations using neutron transport cross-sections derived from the ENDF/B-VI data files rather than on the capsule dosimetry measurements. As such, these assigned fluences are based on a methodology that meets the requirements of Regulatory Guide 1.190 and are intended to supersede the neutron exposure values provided in the older reports.

In addition to the calculated surveillance capsule fluence levels reported in Table 7.1-1 of WCAP-15253, the best estimate maximum neutron exposure of the pressure vessel wall projected to 21, 34 and 51 effective full power years is given in Table 8.2-1. These best estimate values can be converted to calculated maximum vessel exposures by dividing the best estimate value by the average BE/C bias factor of 0.87 noted on Table 7.1-1 of WCAP-15253. The resultant projected fluence values based on calculation alone are 1.18E19 n/cm^2, 1.88E19 n/cm^2 and 2.79E19 n/cm^2 for 21, 34, and 51 EFPY, respectively. Using linear interpolation and extrapolation, corresponding maximum fluence values of 1.77E19 n/cm^2 and 2.95E19 n/cm^2 are calculated for 32 EFPY and 54 EFPY of operation, respectively.

The footnotes accompanying Table B.3.26-1 of the Application are intended to indicate which of the McGuire Unit 1 surveillance capsule exposures most closely match the corresponding projected vessel fluence at the irradiation times stated. For example, footnote (b) indicates that the actual Capsule V exposure of 2.08E19 n/cm^2 is the closest available data set to the projected 32 EFPY vessel exposure of 1.77E19 n/cm^2. Likewise, footnote (d) indicates that the actual Capsule Y fluence of 2.86E19 n/cm^2 provides a data set that is close to the projected 54 EFPY vessel exposure of 2.95E19 n/cm^2.

RAI B.3.26-4

For McGuire Unit 2:Table B.3.26-1 of the submittal reports a 54 EFPY value at 1/4T referenced to WCAP-13516 which does not report values above 32 EFPY. How was that value derived? The 1/4T, 32 EFPY value reported in the same table and referenced to WCAP-12556 does not agree with the value reported in the table. Please explain. The 54 EFPY ID value reported in the same table and referenced to WCAP-14799 does not exist in WCAP-14799 which does not report 54 EFPY values. Please explain why. The 32 EFPY ID value reported in the same table was calculated with ENDF/B-IV cross-sections in WCAP-13516. In addition, justify why this value was not re-evaluated especially when the location of the surveillance capsule is behind the neutron pad.

Response to RAI B.3.26-4

The neutron fluence values listed in Table B.3.26-1 provide the actual or projected neutron exposure of the reactor vessel materials surveillance capsules irradiated in McGuire Unit 2. Since all of the surveillance capsules have been withdrawn from the reactor, the fluence values listed in Table B.3.26-2-1 of the Application represent the calculated plant specific neutron exposure accrued by each capsule up to the time of withdrawal. The fluence values provided in Table B.3.26-1 do not represent the plant specific exposure of the McGuire Unit 2 pressure vessel wall.

The following table provides a comparison of the capsule fluence values provided in the series of reports that summarize the McGuire Unit 2 Reactor Vessel Materials Surveillance Program:

	Reported Fluence (E > 1.0 MeV) [n/cm^2]					
Capsule	WCAP 11029 (1986)	WCAP 12556 (1990)	WCAP 13516 (1992)	WCAP 14231 (1994)	WCAP 14799 (1997)	WCAP 15334 (1999)
V	3.06E18	-	3.37E18	3.33E18	3.20E18	3.23E18
X	-	1.45E19	1.45E19	1.38E19	1.46E19	1.47E19
U	-	-	2.02E19	2.12E19	2.02E19	2.04E19
Z	-	-	-	2.28E19	2.36E19	2.41E19
Y	-	-	-	2.03E19	2.06E19	2.08E19
W	-	-	-	-	3.01E19	3.07E19

The changes in the assigned capsule fluences are due in part to a continuous methodology improvement over the last 18 years as well as to a change in NRC staff philosophy relative to the use of calculated rather than measured or adjusted fluence in vessel integrity assessments.

The methodologies reflected in each of these surveillance capsule evaluation reports are summarized as follows:

WCAP	Basis for Capsule Fluence	Transport Calculation Methodology	Transport X-Sec Basis	Dosimetry Evaluation Methodology	Dosimetry X-Sec Basis
11029	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Spectrum Averaged X-Sec Based On S_n Calc.	ENDF/B-IV
12556	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
13516	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
14231	Measurement	S_n Transport	ENDF/B-IV (SAILOR)	Least Squares	ENDF/B-V
14799	Calculation	S_n Transport	ENDF/B-VI (BUGLE-93)	Least Squares	ENDF/B-VI (SNLRML)
15334	Calculation	S_n Transport	ENDF/B-VI (BUGLE-96)	Least Squares	ENDF/B-VI (SNLRML)

The capsule fluence values reported in WCAP-15334 are based on calculations using neutron transport cross-sections derived from the ENDF/B-VI data files rather than on the capsule dosimetry measurements. As such, these assigned fluences are based on a methodology that meets the requirements of Regulatory Guide 1.190 and are intended to supersede the neutron exposure values provided in the older reports.

In addition to the calculated surveillance capsule fluence levels reported in Table 7.1-1 of WCAP-15334, the best estimate maximum neutron exposure of the pressure vessel wall projected to 21, 34 and 51 effective full power years is given in Table 8.2-1. These best estimate values can be converted to calculated maximum vessel exposures by dividing the best estimate value by the average BE/C bias factor of 0.91 noted on Table 7.1-1 of WCAP-15334. The resultant projected fluence values based on calculation alone are 1.18E19 n/cm^2, 1.85E19 n/cm^2 and 2.71E19 n/cm^2 for 21, 34, and 51 EFPY, respectively. Using linear interpolation and extrapolation, corresponding maximum fluence values of 1.74E19 n/cm^2 and 2.87E19 n/cm^2 are calculated for 32 EFPY and 54 EFPY of operation, respectively.

The footnotes accompanying Table B.3.26-1 of the Application are intended to indicate which of the McGuire Unit 2 surveillance Capsule exposures most closely match the corresponding projected vessel fluence at the irradiation times stated. For example, footnote (b) indicates that the actual Capsule U exposure of 2.04E19 n/cm^2 is the closest available data set to the projected 32 EFPY vessel exposure of 1.74E19 n/cm^2. Likewise, footnote (d) indicates that the actual Capsule W fluence of 3.07E19 n/cm^2 will provide a data set close to the projected 54 EFPY vessel exposure of 2.87E19 n/cm^2.

B.3.27 Reactor Vessel Internals Inspection Program

RAI B.3.27-1

The applicant has identified change in dimensions due to void swelling as an applicable aging effect; it will be managed by the Reactor Vessel Internals Inspection. In Section B.3.27 "Monitoring and Trending", the applicant states that McGuire and Catawba will rely upon the results of the inspections at Oconee to assess the effects of void swelling. It is not clear to the staff whether the Oconee results will be applicable to McGuire and Catawba, because the RVI components are of different designs (B&W vs. Westinghouse), may utilize different materials of construction, and may be subject to different fluence rates. Provide additional information that supports the technical validity of this extrapolation, specifically addressing the similarities and differences pertaining to RVI design details; materials of construction; reactor power rating and neutron fluence levels; and critical locations where dimensional changes may compromise performance of intended functions.

Response to RAI B.3.27-1

Currently, limited data from pressurized water reactor internals are available to properly evaluate the potential for dimensional changes due to swelling. Additional data is needed to properly evaluate the most susceptible locations for inspections. Oconee inspections will provide some of that data prior to 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 twenty-year period of extended operation or about 2015. Based on the Oconee inspections as well as results from other internals inspections in the industry, Duke prepared the inspection plan for McGuire 1. The McGuire Unit 1 internals inspection is currently planned during the fifth inservice inspection interval.

Based on the information presented in the following table, Duke believes that design and operation of Oconee is similar to that of McGuire and Catawba (e.g., power level, materials of construction temperatures and estimated fluences):

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

RAI B.27-2 (from NRC letter dated January 30, 2002)
Examination Category B-N-3, for removable core support structures, is directly applicable to the RVI components. This requires visual VT-3 examination of all accessible parts of the RVI components. Cracks initiated by stress corrosion cracking or fatigue will start off very small and will grow over time. VT-3 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 RVI components, indicates that a visual inspection will be performed on components fabricated from plates, forgings and welds to detect the effects of cracking. For RVI plates, forgings and welds, the staff requests 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. If VT-3 is the proposed inspection method, please justify the use of this method for identifying small cracks, or describe enhancements planned to augment this inspection activity. Also, please indicate the frequency of inspections for all inspection types described in this aging management program.

Response to RAI B.27-2
The *Reactor Vessel Internals Inspection* is a program that is completely separate from the *Inservice Inspection Plan*. As described in Section B.27 of the Application, the *Reactor Vessel Internals Inspection* has been developed to supplement the *Inservice Inspection Plan* and is separate from and in addition to the VT-3 examinations currently required by examination category B-N-3.

The *Reactor Vessel Internals Inspection* includes several inspections and examinations. For items comprised of plates, forgings, and welds that will be visually inspected, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed prior to the inspection. The visual inspection method will be sufficient to detect the critical crack size determined by analysis.

Currently an inspection for McGuire Unit 1 is planned during the fifth inservice inspection interval (approximately between forty and fifty years of operation). The decision of whether to perform inspections on McGuire Unit 2, Catawba Unit 1 and Catawba Unit 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 Unit 1. Refer to the discussion in response to RAI B.27-1 for more details on the relevance of the Oconee experience.

Attachment 2
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letter dated January 23, 2002

2.3.2 System Scoping and Screening Results - Engineered Safety Features

General Ventilation System Questions (from Sections 2.3.2 and 2.3.3 of LRA)

RAI 2.3-1

The following are seven staff observations pertaining to fan housings and air handling unit housings identified on various McGuire and Catawba ventilation system flow diagrams that were referenced in the LRA:

1. Fan housings are not consistently highlighted on McGuire annulus ventilation system flow diagrams. Fan housings are highlighted on McGuire unit 2 (MC-2564-1 at I-7 and F-7), but not on unit 1 (MC-1564-1 at I-7 and G-7).

2. Fan housings are highlighted on auxiliary building ventilation system flow diagrams for McGuire (MC-1577-1 at H-11 and G-11; MC-1577-2 at F-2, F-13, H-2 and H-13; MC-2577-1 at G-12 and F-12) and Catawba (CN-1577-1.2 at F-3, F-5, F-10 and F-12; CN-1577-1.8 at H-9, H-12, K-9 and K-12).

3. Fan housings are highlighted on control area ventilation system flow diagrams for McGuire (MC-1577-1 at H-11 and G-11; MC-1578-1 at I-6, G-7 and E-6; MC-1578-3 at B-8 and C-9; MC-1578-4 at C-2, C-9, E-2, E-9, I-2, I-9, K-2 and K-9) and Catawba (CN-1578-1 at E-10 and H-10).

4. Air handling unit housings are highlighted on control area ventilation system flow diagrams for McGuire (MC-1578-1 at H-10 and E-10; MC-1578-1.1 at I-8 and D-8) and Catawba (CN-1578-1 at H-7and E-7; CN-1578-1.1 at I-5 and I-10; CN-1578-1.3 at C-4, C-10, E-4, E-10, H-4, H-10, K-4 and K-10).

5. Fan housings are highlighted on diesel building ventilation flow diagrams for McGuire (MC-1579-1 at C-6, E-6, G-6, H-6, J-6 and K-6; MC-2579-1 at C-6, E-6, G-6, H-6, J-6 and K-6) and Catawba (CN-1579-1 at C-6, D-6, F-6, G-6, I-6 and K-6). However, Catawba Unit 2 diesel building ventilation fan housings are not highlighted (CN-2579-1 at C-6, D-6, F-6, G-6, I-6 and K-6). The highlighting of diesel building ventilation fan housings on the flow diagrams is inconsistent.

6. Fan housings are highlighted on the fuel handling building ventilation system flow diagrams for McGuire (MC-1577-1 at H-11 and G11; MC-1577-3 at K-12 and J-12; MC-2577-1 at G-12 and F-12; MC-2577-3 at K-12 and J-12) and Catawba (CN-1577-2.0 at K-6, K-13, C-6 and C13; CN-2577-2.0 at K-6, K-13, D-6 and D-13).

7. Ventilation fan housings are highlighted on the McGuire turbine building ventilation system flow diagram (MC-1614-4 at J-5, J-11, H-11 and G-9).

Some, but not all fan housings, were highlighted to indicate that they within scope, presumably based on the ventilation pressure boundary intended function. Ventilation fan housings and air handling unit housings are passive, long-lived components that serve a pressure boundary function. However, these components were not identified in the ventilation aging management review results tables to indicate that they were subject to an AMR. The staff also notes that containment air return fan housings were not included in Table 3.2-3 of the LRA for either McGuire or Catawba. Please indicate if ventilation fan housings and air handling unit housings are subject to an AMR and, if so, provide the relevant information about these components to complete the AMR results tables of the LRA. If these components are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-1

The red, triangular LR flags define the license renewal evaluation boundaries on mechanical system flow diagrams, and highlighting was used as an aid to Duke in component screening and for the reviewer in understanding the system under review. In some cases, components were outlined in highlighting, and in others, the highlighting was simply drawn through components. Either way is acceptable for achieving the purpose of the drawings. The components are shown to be within the license renewal evaluation boundaries, and therefore, within the scope of license renewal.

The air handling unit housings cited in RAI 2.3-1, Item 4, are subject to aging management review and are listed in Table 3.3-11 (page 3.3-111, row 1) as Air Handling Units (Heat Exchanger Shells).

Cooling fans are not included in the aging management review results tables in the Application. Cooling fans, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (<u>underline</u> added to highlight cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment

hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

RAI 2.3-2

Ventilation damper housings are identified and highlighted as within scope on various McGuire and Catawba ventilation system flow diagrams that were referenced in the LRA. For example, ventilation damper housings are highlighted on the McGuire fuel handling building ventilation system flow diagram (MC-2577-1 at H-11 and F-10) and on the McGuire turbine building ventilation system flow diagram (MC-1614-4 at K-5, G-8, G-11, E-11 and D-11). Ventilation damper housings are passive, long-lived components that serve a pressure boundary function. However, these damper housings are not identified in the ventilation system aging management review results tables of the LRA. The staff also notes that containment air return damper housings were not included in Table 3.2-3 of the LRA for either McGuire or Catawba. In addition, most other McGuire and Catawba damper housings are not identified on either system flow diagrams or in aging management results tables, which list the components subject to an AMR. Identify whether ventilation damper housings are subject to an AMR and, if so, provide the relevant information about these components to complete the aging management review results tables of the LRA. If these components are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-2

Ventilation dampers are not included in the aging management review results tables in the Application. Ventilation dampers, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight ventilation damper exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

RAI 2.3-3
The following are seven staff observations pertaining to ventilation system instrument monitors identified on various McGuire and Catawba ventilation system flow diagrams that were referenced in the LRA:

1. McGuire radiation monitors are not highlighted on either auxiliary building ventilation system flow diagrams (MC-1577-1 at H-10; MC-2577-1 at G-9) or identified in Table 3.3-1 of the LRA.

2. Smoke detectors are identified on Catawba auxiliary building ventilation system flow diagrams (CN-1577-1.0 at H-3, H-6, H-9 and H-11).

3. Air flow sensors identified in Table 3.3-1 of the LRA are not highlighted on either McGuire or Catawba auxiliary building ventilation system flow diagrams.

4. Radiation monitors are highlighted on a McGuire control area ventilation system flow diagram (MC-1578-1 at I-1 and F-1). Radiation monitors are shown but not highlighted on a Catawba control area ventilation system flow diagram (CN-1578-1 at J-13 and C-13).

5. Chlorine and smoke detection monitors are not consistently highlighted on the control area ventilation flow diagrams or Table 3.3-11 of the LRA with respect to the ventilation pressure boundary intended function. These monitors are not mentioned in Section 2.3.3.8 of the LR relative to scope and an AMR.

6. Radiation monitors are highlighted on McGuire fuel handling building ventilation system flow diagrams (MC-1577-3 at K-8) and (MC-2577-3 at K-8).

7. Smoke detectors are highlighted on Catawba fuel handling building ventilation system flow diagrams (CN-1577-2.1 at G-4) and (CN-2577-2.1 at G-4).

These ventilation system instrument monitors would appear to perform a pressure boundary intended function. However, they are not consistently highlighted on the system flow diagrams referenced in the LRA. Nor are they listed in the AMR result tables, which identify those instruments subject to an AMR. Indicate if the identified instruments are open to ventilation process flow, perform a pressure boundary intended function, and are subject to an AMR. If so, provide the relevant information to clarify any discrepancy between the AMR results tables and ventilation system flow diagrams in the LRA. Similarly, provide the relevant information about the chlorine and smoke detection monitors to complete Table 3.3-11 in the LRA. If these monitors or other ventilation system instruments are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-3

Referring to the seven numbered staff observations in RAI 2.3-3, for items (1), (4) and (6), radiation monitors should have been highlighted on all referenced flow diagrams, indicating that they are within the license renewal evaluation boundaries of the Auxiliary Building Ventilation System, the Control Area Ventilation System and the Fuel Handling Building Ventilation System. The radiation monitors are, therefore, within the scope of license renewal. However, in accordance with the guidance provided in NEI 95-10, Revision 3, radiation monitors are not considered passive components (Appendix B, Item 95), and are therefore not subject to an aging management review.

For items (2), (5) and (7), smoke detectors are also shown on CN-1577-1.0 at coordinates C-3, E-5, E-10, and C-12. Smoke detectors and chlorine detectors are within the component group "alarm units, gas analyzers or instruments" that, in accordance with the guidance provided in NEI 95-10, Revision 3, are not considered passive components, and are therefore not subject to an aging management review. Also, the passive components of smoke and chlorine detectors (e.g., housings) do not have either a pressure boundary function (they are duct-mounted with only electrical components penetrating the ductwork pressure boundary) or any other component intended function for license renewal. Therefore, smoke detectors and chlorine detectors are not subject to an aging management review

For item (3), the air flow sensors (air flow monitors) listed in Table 3.3-1 of the Application are the components identified as air flow monitors are highlighted on Auxiliary Building Ventilation System flow diagrams as follows:

- MC-1577-1 (D-8 and H-12)
- MC-2577-1 (D-8 and G-13)
- CN-1577-1.2 (E-4 and E-11)
- CN-1577-1.3 (H-2, H-7, H-8 and H-13)

RAI 2.3-4

Clarify whether or not sealants used to maintain the power block building pressure boundary envelopes (e.g., main control room, auxiliary building, fuel handling building, containment) at design pressure with respect to the adjacent area are included in the scope of the application and subject to an AMR. In particular, please indicate if sealant material was used to remove potential bypass leak paths following the McGuire modification (described in the LRA and the UFSAR) to install containment personnel access hatches and pipe penetrations. If so, please indicate if the sealant material is within the scope of license renewal and subject to an aging management review. If so, please provide the relevant information necessary for the staff to complete its review of the aging management review result tables in the LRA. If the sealants are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-4

Duke does not define materials such as sealants to be structures or components. However, Duke recognizes that limited situations may exist where these materials are important in maintaining the integrity of the component to which they are connected. For this situation, the license renewal or component intended function supported by the sealant is to maintain the building pressure boundary envelope. The pressure boundary function is addressed by surveillance testing to demonstrate compliance with McGuire and Catawba Technical Specifications. The testing is performed on the frequency specified in the technical specifications to ensure the integrity of the building pressure boundary envelope. The following information identifies the building envelopes and the technical specifications which address those envelopes:

- The sealants for the Control Room pressure boundary envelope are addressed by surveillance testing to demonstrate compliance with McGuire Technical Specification 3.7.9 and Catawba Technical Specification 3.7.10.
- The sealants for the Auxiliary Building pressure boundary envelope are addressed by surveillance testing to demonstrate compliance with McGuire Technical Specification 3.7.11 and Catawba Technical Specification 3.7.12.
- The sealants for the Fuel Building pressure boundary envelope are addressed by surveillance testing to demonstrate compliance with McGuire Technical Specification 3.7.12 and Catawba Technical Specification 3.7.13.
- The sealants for the Reactor Building pressure boundary envelope are addressed by surveillance testing to demonstrate compliance with McGuire and Catawba Technical Specification 3.6.10.

The McGuire modifications discussed in the RAI were described in McGuire UFSAR Section 6.2.3.3 and were not described in the Application. The modifications were made to the containment personnel access hatches and to the mainsteam and feedwater piping penetrations in order to remove potential bypass leak paths. In the case of the personnel hatches, an enclosure was added around the outside of the hatch such that any leakage past the doors seals is directed back to the annulus. Similarly, for the main steam and feedwater penetrations, the test connections on the outer bellows of each penetration were routed back to the annulus such that any leakage past the inner bellows is into the annulus. In both of these modifications, sealants were not used.

RAI 2.3-5
The following five passive components associated with ventilation system ductwork are not identified as within scope of license renewal or subject to an AMR:

1. Ductwork turning vanes
2. Ventilation system elastomer seals and flexible collars
3. Ventilation equipment vibration isolators flexible connections
4. Ductwork test connections
5. Supply and return air grilles highlighted on ventilation system flow diagrams

Indicate if these components are subject to an AMR, and if so provide relevant information about the components to complete the aging management review result tables. If these components are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-5
Referring to the five passive components identified in RAI 2.3-5, for item (1), ductwork turning vanes are within the scope of license renewal and subject to an aging management review. Turning vanes are constructed of the same material as the duct in which they reside and are considered to be a subcomponent of the duct. Therefore, turning vanes are included in the aging management review result for ductwork.

For items (2) and (3), ventilation system elastomer seals and flexible collars along with ventilation equipment vibration isolator flexible connections are within scope and subject to an aging management review. The results of the aging management review are presented in the response to RAI 3.3-1 in Attachment 4.

For item (4), ductwork test connections are within the scope of license renewal and subject to an aging management review. Ductwork test connections are considered to be a fitting in the ductwork and are included in the table entries for "Ductwork" in the Application. Treatment of the test connections is consistent with the treatment of pipe fittings in piping systems included in the Application. In both instances, the fittings are not listed in the Application.

For item (5), supply and return air grilles are within the scope of license renewal but are not subject to an aging management review. The grilles do not perform a component intended function in support of any system function that meets the criteria of §54.4. The grilles are installed for aesthetic purposes only.

RAI 2.3-6

Describe the areas that constitute the main control room envelope for the McGuire and Catawba nuclear station units. Verify that all control area ventilation system components inside the main control room envelope relied on to perform safety-related cooling and filtration functions to maintain the control room habitable are identified. Please indicate if components inside the main control room envelope (e.g., air handling units; fan coil units with their associated ductwork; ventilation dampers; fire dampers; control valves; air intake dampers; exhaust fan with purge ductwork; and transfer grilles) are within the scope of license renewal and, for the active components, please indicate if their housings are subject to an AMR. If these components are not within the scope of license renewal, or if their housings are not considered subject to an AMR, please provide a justification for their exclusion.

Response to RAI 2.3-6

Referring to the flow diagrams provided with the Application, the areas that constitute the McGuire control room envelope are areas designated on MC-1578-2 as the Control Room, Instrument Room, and Storage Room. For Catawba, the areas that constitute the control room envelope are areas designated on CN-1578-1.0 as the Control Room, Operator's Office, and Interface Office. The control area ventilation system components inside the main control room envelope relied on to perform safety-related cooling and filtration functions to maintain the control room habitable are within the license renewal evaluation boundaries shown on the highlighted flow diagrams for the Control Area Ventilation System. Components within those evaluation boundaries that are subject to aging management review are presented in Table 3.3-11 of the Application. Table 3.3-11 lists components such as air handling units, ductwork, and valve bodies. Components such as ventilation dampers and cooling fans are not included in the aging management review results tables in the Application as ventilation dampers and cooling fans, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (<u>underline</u> added to highlight ventilation damper and cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, <u>excluding</u>, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, <u>ventilation dampers</u>, pressure transmitters, pressure indicators, water level indicators, switchgears, <u>cooling fans</u>, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

RAI 2.3-7
The following component housings are identified on ventilation system flow diagrams referenced in the LRA as being within the scope of license renewal:

1. Auxiliary building ventilation moisture eliminators are identified on Catawba flow diagrams (CN-1577-1.3 at J-2, J-7, J-8 and J-13).

2. Control area ventilation system moisture eliminators and pre-filters are highlighted on a Catawba flow diagram (CN-1578-1 at E-12 and H-12).

3. McGuire diesel building duct heater housings are highlighted on McGuire unit 1 flow diagram (MC-1579-1 at E-7 and J-8) and not highlighted on McGuire unit 2 flow diagram (MC-2579-1 at E-8 and J-8).

4. The ductwork connection from the auxiliary building ventilation system to the Catawba unit 1 vent is shown highlighted as within scope (CN-1577-1.2 at F-11) but is not highlighted as within scope on the Catawba interface drawing to the unit 2 vent (CN-2577-3.0 at E-7).

5. A transfer damper is highlighted on a Catawba fuel handling building ventilation system flow diagram (CN-2577-2.0 at J-5).

6. Turbine building ventilation duct heater housings are highlighted on a McGuire flow diagram (MC-1614-4 at J-7 and H-7).

7. A turbine building ventilation system pre-filter housing is highlighted on a McGuire flow diagram (MC-1614-4 at I-5).

These components would appear to perform some pressure boundary intended function; however, they are not included in the aging management review results tables of the LRA. Indicate if these components are subject to an AMR and, if so, provide the relevant information about these components to enable the staff to complete its review of the aging management review result tables in the LRA. If these components are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-7
Referring to the seven components identified in RAI 2.3-7, for item (1), the Auxiliary Building Ventilation System moisture eliminators are subject to aging management review and are a subcomponent of the component on drawing CN-1577-1.3 named "PRHDS-XX" (where "XX" is

the unit and train designation). This set of components is identified in Table 3.3-1 (page 3.3-8, row 1) of the Application as "Pump Room Heater-Demister (CNS Only)."

For item (2), the Control Area Ventilation System moisture eliminators and pre-filters are subject to aging management review and are a subcomponent of the component on drawing CN-1578-1 named "CRA-PFT." This set of components is identified in Table 3.3-11 (page 3.3-111, row 5) of the Application as "Control Room Area Pressurizing Filter Trains (CNS Only)."

For item (3), the Diesel Building Ventilation System duct heaters should have been highlighted on flow diagram MC-2579-1, indicating that they are within the scope of license renewal. This issue is the same as RAI 2.3.3.10-1. For the Diesel Building Ventilation System duct heaters in item (3) and the Turbine Building Ventilation System duct heaters in item (6), the duct heaters consist of electric heating elements that are mounted inside the ductwork. The duct-mounted electrical heating elements do not have a pressure boundary function or any other component intended function for license renewal and are, therefore, not subject to an aging management review.

For item (4), the ductwork connection from the Auxiliary Building Ventilation System to the Unit 2 Vent (shown on flow diagram CN-1577-1.2 at F-11) should have been highlighted on flow diagram CN-2577-3.0 at E-7. Ductwork for this section is contained in Table 3.3-1 (page 3.3-6, row 4) of the Application.

For item (5), while the ventilation damper is highlighted on flow diagram CN-2577-2.0, indicating that it is within the scope of license renewal, ventilation dampers are not included in the aging management review results tables in the Application. Ventilation dampers, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (<u>underline</u> added to highlight ventilation damper exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, <u>excluding</u>, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, <u>ventilation dampers</u>, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

For item (7), the Turbine Building Ventilation System pre-filters that are shown on flow diagram MC-1614-4 are removable components within the air handling units. The air handling units are listed in Table 3.3-46 (page 3.3-257, row 1) in the Application. Filtration is not required of the pre-filters in support of the Turbine Building Ventilation System function within the scope of license renewal. Therefore, system pre-filters are excluded from an aging management review.

RAI 2.3-8

The following components were identified in sections and tables of the LRA as being within scope, but were not highlighted on the referenced ventilation flow diagrams.

1. Control area ventilation system orifices identified in Table 3.3-11 of the LRA are not highlighted on McGuire control area ventilation system flow diagrams.

2. Control area ventilation system air handling unit heat exchanger shells and pre-filters are not highlighted to indicate they are within license renewal scope on a McGuire system flow diagram (MC-1578-4 at K-2, K-8, I-2, I-8, E-2, E-8, C-2 and C-8).

3. McGuire and Catawba valve bodies (or damper housings) are not highlighted on diesel building ventilation system flow diagram drawings.

4. Pipe (McGuire only) is not highlighted on diesel building ventilation system flow diagrams.

5. Catawba unit 1 diesel building ventilation system inlet ductwork (CN-1579-1) is highlighted with a single LR flag. Diesel building ventilation system inlet ductwork at McGuire (MC-1579-1 at 1-E and 1-J; MC-2579-1 at 1-E and 1-J) and Catawba unit 2 (CN-2579-1 at 10 locations) is highlighted with double LR flags.

6. A filter housing located on a McGuire fuel handling building ventilation system flow diagram is not highlighted (MC-1577-3 at J-10).

7. McGuire and Catawba valve bodies (or damper housings) are not highlighted on any fuel building ventilation system flow diagram.

8. Nuclear service water pump structure ventilation system valve bodies (or damper housings) identified in Table 3.3-38 of the LRA as being within scope are not included in the Catawba nuclear service water pump structure ventilation system flow diagram.

Please indicate if these components are within the scope of license renewal and subject to an AMR. If so, provide the relevant information about the components to coordinate between the table and drawings and complete the aging management review result tables of the LRA. If the components are not in scope or considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-8

Prior to providing specific responses to each item in RAI 2.3-8, a point of clarification is offered to the reviewer. The tables in the Application indicate those components that are subject to an aging management review. The tables do not indicate all components within the scope of license renewal as stated in the RAI. The red, triangular LR flags define the license renewal evaluation boundaries on mechanical system flow diagrams.

Referring to the eight components identified in RAI 2.3-8, for item (1), the Control Area Ventilation System orifice that is identified in Table 3.3-11 (page 3.3-112, row 3) of the Application is highlighted on flow diagram MC-1578-1.0 at E-3.

For item (2), the red, triangular LR flags define the license renewal evaluation boundaries on mechanical system flow diagrams, and highlighting was used as an aid to Duke in component screening and for the reviewer in understanding the system under review. In some cases, components were outlined in highlighting, and in others, the highlighting was simply drawn through components. Either way is acceptable for achieving the purpose of the drawings. The components are shown to be within the license renewal evaluation boundaries, and therefore, within the scope of license renewal. The Control Area Ventilation System air handling units cited are shown on MC-1578-4.0 to be within the evaluation boundaries, indicating that they are within the scope of license renewal. The air handling units are included in Table 3.3-11 (page 3.3-111, row 1) of the Application.

For item (3), by the highlighting convention described in the response to item (2) above, ventilation dampers are highlighted and shown on the flow diagrams to be within the license renewal evaluation boundaries of the Diesel Building Ventilation System. While the ventilation dampers are within the scope of license renewal, ventilation dampers are not included in the aging management review results tables in the Application. Ventilation dampers, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (<u>underline</u> added to highlight ventilation damper exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, <u>excluding</u>, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air

compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

The valve bodies listed in Table 3.3-13 (page 3.3-116, rows 5 through 9) of the Application for the Diesel Building Ventilation System are associated with in-scope instruments, which by convention, are not highlighted on mechanical system flow diagrams. Instruments and instrumentation components are within scope if they are attached to process pipe, ductwork or other components that are within scope.

For item (4), the pipe components listed in Table 3.3-13 (page 3.3-116, rows 2 and 3) of the Application for the Diesel Building Ventilation System are associated with in-scope instruments which by convention, are not highlighted on mechanical system flow diagrams.

For item (5), double LR flags should have been shown for the inlet ductwork on CN-1579-1. Ductwork for this section is contained in Table 3.3-13 (page 3.3-116, row 1) of the Application.

For item (6), by the highlighting convention described in the response to item (2) above, the filter units are highlighted and shown on the flow diagrams to be within the license renewal evaluation boundaries of the Fuel Handling Building Ventilation System. Filters consist of a housing and medium. The filter housing is listed in Table 3.3-28 (page 3.3-192, row 3) of the Application as "Filter." From the March 10, 2000 letter to Douglas J. Walters (NEI) from Christopher I. Grimes (NRC), filter mediums are excluded from an aging management review in that they are replaced on condition. The Fuel Handling Building Ventilation System filter mediums are periodically tested and replaced when test results warrant. Therefore, filter mediums are excluded from an aging management review.

For item (7), by the highlighting convention described in the response to item (2) above, dampers are highlighted and shown on the flow diagrams to be within the license renewal evaluation boundaries of the Fuel Handling Building Ventilation System. While the ventilation dampers are within the scope of license renewal, ventilation dampers are not included in the aging management review results tables in the Application. Ventilation dampers, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. Further details to aid to the reviewer are provided in the response to item (3) above.

The valve bodies listed in Table 3.3-28 (page 3.3-192, rows 7 through 9) of the Application for the Fuel Handling Building Ventilation System are associated with in-scope instruments which by convention, are not highlighted on mechanical system flow diagrams.

For item (8), by the highlighting convention described in the response to item (2) above, dampers are highlighted and shown on the flow diagrams to be within the license renewal evaluation boundaries of the Nuclear Service Water Pump Structure Ventilation System. While the ventilation dampers are within the scope of license renewal, ventilation dampers are not included in the aging management review results tables in the Application. Ventilation dampers, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. Further details to aid to the reviewer are provided in the response to item (3) above.

The valve bodies listed in Table 3.3-38 (page 3.3-229) of the Application for the Nuclear Service Water Pump Structure Ventilation System are associated with in-scope instruments which by convention, are not highlighted on mechanical system flow diagrams.

RAI 2.3-9

The following ventilation components identified in the application and discussed in each plant's respective UFSAR have not been included as part of the application screening process.

1. Catawba refrigerant coils serving the shutdown panel areas for both units 1 and 2 are not highlighted (CN-1577-1.8 at K-9, K-12, H-9 and H-12). Review of Catawba UFSAR design basis section 9.4.3.1 indicates that the auxiliary shutdown panel room air-conditioning subsystem is an engineered safety feature. This system flow diagram highlighting is inconsistent with a similar Catawba standby shutdown facility (SSF) self contained air-conditioning packages. Contrary to the sectional auxiliary shutdown panel room air-conditioning subsystem highlighting, the entire SSF self-contained air-conditioning components are highlighted to include the condensing unit, air handling unit, and pre-filter (CN-1579-4.3 at H-3).

2. The nuclear service water pump structure ventilation system full capacity fan housings are not identified in the aging management review results table 3.3-38 of the application or highlighted on the system flow diagram(CN-1557-2.0 at G-3, G-5, G-10 and G-12). Section 9.4.8.3 of the Catawba UFSAR identify the nuclear service water pump structure ventilation system as an engineered safety feature.

3. The fuel handling building ventilation 'filtration' intended function is not identified in the aging management review results table 3.3-28 of the LRA for filter component types. This is not consistent with the identified component intended function of another application filter train (refer to table 3.3-11 of the control area ventilation system). Section 2.3.3.20 of the fuel handling building ventilation system section of the application identifies control of airborne radioactivity in the fuel pool area following a postulated fuel handling accident as a design basis. In addition, Section 9.4.2.3 of the Catawba UFSAR safety evaluation identifies the fuel building exhaust system as an engineered safety feature.

Indicate if these ventilation components are subject to an AMR and, if so, provide the relevant information about the components to enable the staff to complete its review of the aging management review result tables in the LRA. If these components are not considered subject to an AMR, provide a justification for their exclusion.

Response to RAI 2.3-9

Referring to the three components identified in RAI 2.3-8, for item (1), the refrigerant coils associated with the auxiliary shutdown panel room air-conditioning sub-system of the Catawba Auxiliary Building Ventilation System are within the scope of license renewal and should have been highlighted on flow diagram CN-1577-1.8. They are shown to be within the license renewal evaluation boundaries, as defined by the red, triangular LR flags. The coils are listed in Table 3.3-1 (page 3.3-8, rows 2 through 4 and page 3.3-9, rows 1 through 3) of the Application as "Shutdown Panel Area Air-Conditioning Unit Condenser (CNS Only)," with tubes, tube sheets, shells and bonnets listed separately, along with the associated aging management review results.

For item (2), cooling fans are not included in the aging management review results tables in the Application. Cooling fans, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

For item (3), the Fuel Handling Building Ventilation System filters consist of housings and mediums. The "filter" entry in Table 3.3-28 (page 3.3-192, row 3) in the Application applies only to the filter housing in this case which do serve a pressure boundary function. From the March 10, 2000 letter to Douglas J. Walters (NEI) from Christopher I. Grimes (NRC), filter mediums are excluded from an aging management review in that they are replaced on condition. The Fuel Handling Building Ventilation System filter mediums are periodically tested and replaced when test results warrant. Therefore, filter mediums are excluded from an aging management review.

2.3.2.3 Containment Air Return Exchange & Hydrogen Skimmer System

RAI 2.3.2.3-1

The applicant has not included within the scope of license renewal any of the containment air return ventilation ductwork at the McGuire Nuclear Station. Though this ductwork is non-safety-related, it appears to support the safety function of the containment air return fans. For instance, the containment peak pressure calculation in the McGuire Updated Final Safety Analysis Report (UFSAR) credits the containment air return fans with providing a 30,000 cfm flow rate from upper to lower containment. Without sufficient integrity of the associated ventilation ductwork, it appears that the containment air return fans would not be capable of performing as assumed to assure containment integrity.

Regulation 10 CFR 54.4(a)(2) states that a non-safety related component whose failure could prevent the satisfactory accomplishment of a safety function is within the scope of license renewal. In that a loss of the integrity of the containment air return ventilation ductwork would apparently prevent satisfactory accomplishment of the accident mitigation function performed by the containment air return fans, the applicant's basis for considering this ductwork outside the scope of license renewal is not understood by the staff.

The staff and the applicant participated in a conference call on October 11, 2001. A summary of this conference call was issued November 14, 2001. The staff and applicant discussed drawings MC-1557-1.0, and MC-2557-1.0, specifically. The staff questioned why the ductwork between the containment air return fans and dampers was not considered to be a pressure boundary and not highlighted as within the scope of license renewal. The staff additionally noted that on drawings CN-1557-1.0 and CN 2557-1.0, the (apparently) analogous ductwork at Catawba was within the scope of license renewal. The applicant indicated that, for McGuire, the dampers are Quality Assurance (QA) Condition 1, safety-related, and within the scope of license renewal as noted by the highlighting on the referenced drawings. The ductwork, however, is classified as QA Condition 4, which is nonsafety-related. As such, only the hangers are within the scope of license renewal because of their function to hold up the ductwork in a seismic event. That is why the MNS drawings are not highlighted for the ductwork between the dampers. The applicant stated that leakage or failure is not a concern for this ductwork (i.e. a failure of the ductwork is not likely) during a non-seismic event. As such, the ductwork is not Class F and is not within the scope of license renewal.

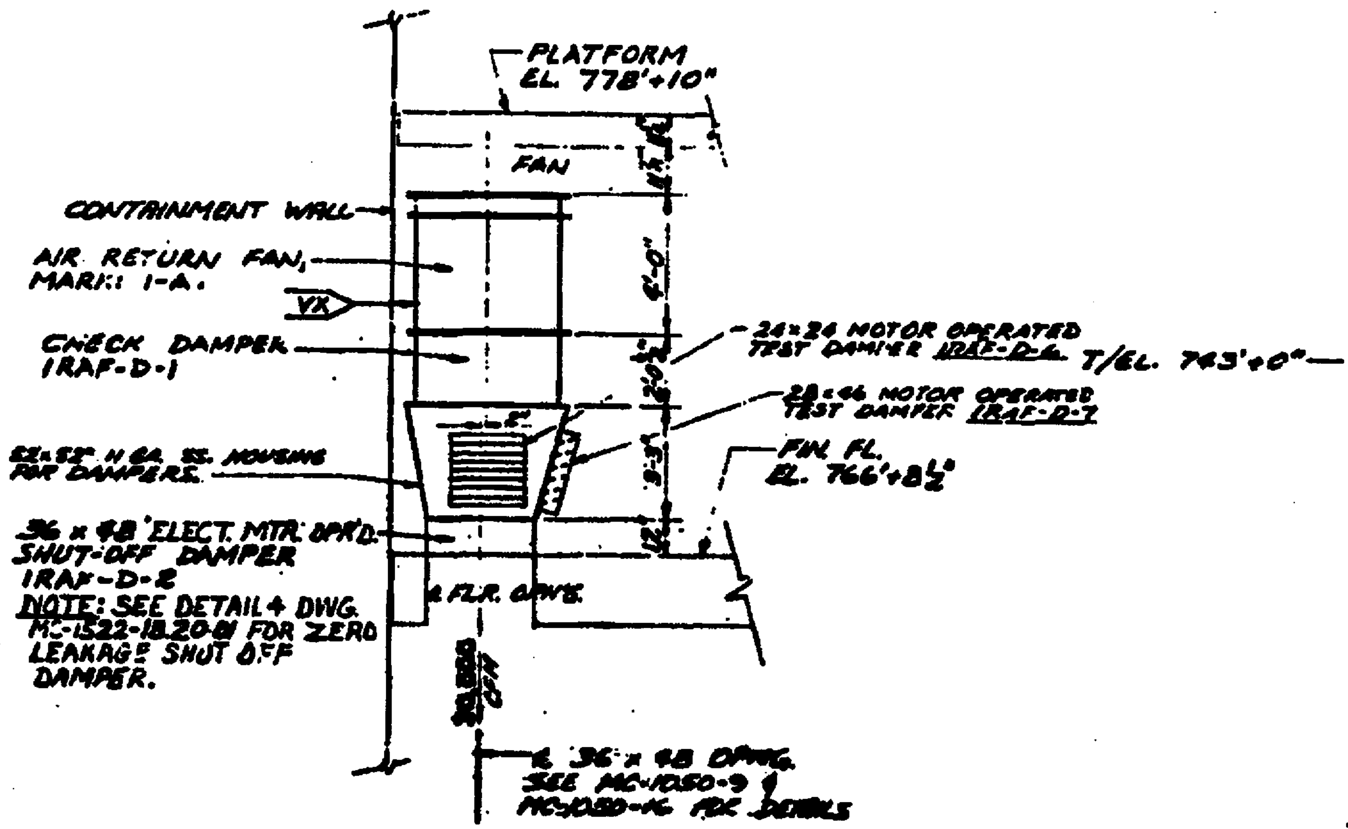
The applicant's statement did not provide a complete resolution, however, because nonsafety-related components may be within the scope of license renewal according to 10 CFR 54.4(a)(2) because their postulated failure could cause the loss of a safety-related function. Specifically, failure of the ventilation ductwork could result from age-related degradation (during the proposed license extension period) and invalidate the UFSAR's assumption concerning containment air return fan performance. Therefore, to complete the staff's evaluation, the following information is requested:

1. Is sufficient integrity of the McGuire containment air return ventilation ductwork necessary in order to satisfy the assumptions made in the UFSAR concerning the safety function of the containment air return fans? (If the applicant believes that the ventilation ductwork is not necessary to support the UFSAR's assumptions, the staff additionally requests a supporting justification and/or analysis.)

2. Considering specifically the criterion given by 10 CFR 54.4(a)(2) and the staff's discussion above, please justify why the McGuire containment air return ductwork has not been included within the scope of license renewal.

Response to RAI 2.3.2.3-1
Upon further review, the flow diagram is misleading with respect to the existence of ductwork in this portion of the system. The flow diagram is intended to be a schematic representation of the physical plant. In contrast, the attached drawing shows a representation of the actual equipment layout as it exists in the plant. It can be seen that no ductwork exists between the containment air return fan and the dampers. The fan is bolted to the check damper (1RAF-D-1), which is bolted to the test damper assembly (the assembly consists of 1RAF-D-5 (which cannot be seen from the view on the drawing), 1RAF-D-6, and 1RAF-D-7). The assembly, in turn, is bolted to the electric motor-operated damper (1RAF-D-2). That entire assembly, which is about 10 feet in height, is mounted to the floor over the floor opening that allows the movement of air. The whole assembly is vendor-supplied and the vendor drawing shows the bolting configuration details. The corresponding train and the Unit 2 configurations are the same as the drawing attached.

Therefore, although the McGuire highlighted drawings are confusing, there are no components missing from within the scope of license renewal. A corrective action report has been entered into the corrective action program to clarify the flow diagrams MC-1557-1.0 and MC-2557-1.0.



SECTION K-K
SCALE: ¼" = 1'-0"

Scanned in drawing for RAI response 2.3.2.3-1

RAI 2.3.2.3-2

The applicant did not expressly include the safety-related hydrogen analyzers for the McGuire and Catawba Nuclear Stations in LRA Section 2.3.2.3. However, the staff reviewer for Section 2.3.2.3 was unable to locate a treatment of their supporting mechanical components elsewhere in the LRA. Because the hydrogen analyzers appear to support the successful operation of the containment hydrogen recombiners, the staff wishes to verify that the applicant has appropriately reviewed hydrogen analyzers' mechanical components. Mechanical components typically used to support hydrogen analyzers' functionality include components used to handle the sampled gas, such as tubing, valves, and a fan or blower.

The UFSARs for McGuire and Catawba indicate that the containment hydrogen recombiners are manually actuated and controlled following an accident. The Catawba UFSAR further specifies that one of the decision criteria for the manual actuation and control of the hydrogen recombiners would be the indications of containment hydrogen concentration provided by the hydrogen analyzers. Therefore, it appears possible that, if failures of the mechanical components supporting the hydrogen analyzers were postulated, the analyzers' false indications could potentially mislead operators into not actuating the recombiners or securing them too early following an accident. If the hydrogen recombiners are not operated as required, it is possible that the analyzed containment hydrogen concentration could be exceeded.

Exceeding the analyzed containment hydrogen concentration could jeopardize the ability to prevent or mitigate the consequences of an accident. Thus, if the analyzed hydrogen concentration could be exceeded in a scenario similar to that postulated in the previous paragraph, it would appear to the staff that the mechanical components supporting the hydrogen analyzers should be included Within the scope of license renewal based upon either 10 CFR 54.4(a)(1)(iii) or (a)(2), depending upon whether or not the supporting mechanical components are safety-related.

Therefore, to complete the staff's evaluation, the following information is requested:

1. To what extent are the safety-related hydrogen analyzers relied upon in the decision-making process governing the manual actuation and control of the containment hydrogen recombiners at McGuire and Catawba? What other factors are considered?

2. Could failures of the mechanical components supporting the hydrogen analyzers result in a containment hydrogen concentration which exceeds the analyzed value at McGuire and Catawba? For example, if failures of the mechanical components supporting the hydrogen analyzers were postulated, would the false indications from the analyzers mislead the operators into not actuating the hydrogen recombiners or securing them too

early following an accident, thereby allowing the containment hydrogen concentration to exceed its analyzed value?

3. What mechanical components are used to support the functioning of the hydrogen analyzers at McGuire and Catawba, and are they safety-related?

4. Does the applicant consider the mechanical components supporting the functioning of the hydrogen analyzers to be within the scope of license renewal for McGuire and Catawba?

5. If piping and instrumentation diagrams exist for the mechanical components supporting the hydrogen analyzers at McGuire and Catawba, the staff would like to receive a copy, with license renewal boundaries marked, as applicable.

Response to RAI 2.3.2.3-2

At issue in RAI 2.3.2.3-2 is the inclusion of the hydrogen analyzers and supporting mechanical components within the scope of license renewal. To address this issue, Duke provides the information below with respect to the hydrogen analyzers and supporting mechanical equipment. In addition, the review performed by Duke for the hydrogen analyzers has identified additional components associated with the Miscellaneous Instrumentation System, including the integrated leak rate test panels and radiation monitors that require review for inclusion within the scope of license renewal. A discussion of these additional components and the Miscellaneous Instrumentation System is provided following the hydrogen analyzer discussion.

The hydrogen analyzers are electrical components, are within the scope of license renewal and are included implicitly in the electrical component sections of the Application. Consistent with guidance contained in NEI 95-10, analyzers are not passive components and are not subject to aging management review. Associated with the hydrogen analyzers are mechanical process components that enable the air to be analyzed. The entire configuration consists of tubing that is open to atmosphere inside the Reactor Building Containment in three locations: upper Containment, the operation level, and steam generator B cavity. The tubing is routed through the steel containment wall, with containment isolation valves on either side. In the Auxiliary Building, the tubing is routed to the hydrogen analyzer. A return line from the hydrogen analyzer is routed back to containment. All of the tubing and valves associated with the hydrogen analyzer as described above are safety-related and within the scope of license renewal. The tubing and valves associated with the hydrogen analyzer are passive, long-lived mechanical components and are subject to aging management review.

The aging management review results for the mechanical components supporting the hydrogen analyzers are presented in the table that follows the discussion of the integrated leak rate test panels and radiation monitors below.

In researching the response to RAI 2.3.2.3-2, Duke referred to the plants' UFSARs. Catawba UFSAR Table 6-77 and McGuire UFSAR Table 6-111 contain lists of the containment penetrations and associated relevant information pertaining to each. (Note: Catawba UFSAR Table 6-77 is not available on the electronic version; a hardcopy version must be reviewed.) Toward the end of each table are the entries associated with the hydrogen analyzers. The hydrogen analyzers are listed in McGuire UFSAR Table 6-111 as Penetration Numbers M239A, M239B, M239C, and M239D. In Catawba UFSAR Table 6-77, the hydrogen analyzers are listed as item numbers 116, 117, 118, and 119. The tables indicate that the hydrogen analyzer penetrations are part of the Miscellaneous Instrumentation (MI) System.

Other penetrations in the tables associated with the Miscellaneous Instrumentation System are the integrated leak rate test (ILRT) connections and containment radiation monitoring. The ILRT connections are in the McGuire UFSAR Table 6-111 as Penetration Numbers 1M255A/2E118A, 1M255B/2E118B, and 1M255C/2E118B and the Catawba UFSAR Table 6-77 as Item Numbers 113, 114, and 115. (Note: McGuire Penetration 1M255C/2E118B contains a typographical error and should be 1M255C/2E118C; this item has been entered into the UFSAR editorial change process.) The penetration class or valve arrangement is listed as A4. McGuire UFSAR Figure 6-172 and Catawba UFSAR Figure 6-112 provide a graphical representation of the piping penetration and valve arrangement. The containment isolation valves and tubing between them are safety related and within the scope of license renewal. The valves, tubing and piping are passive, long-lived components that perform a pressure boundary function and are subject to aging management review. The aging management review results are presented in the table that follows the discussion of the radiation monitors below.

The containment radiation monitors are the third component set in the Miscellaneous Instrumentation System. These monitors are associated with McGuire Penetration Numbers M323A and M323B in McGuire UFSAR Table 6-111 and Catawba Item Numbers 111 and 112 in Catawba UFSAR Table 6-77. The penetration class or valve arrangement is listed as A1. McGuire UFSAR Figure 6-172 and Catawba UFSAR Figure 6-112 provide a graphical representation of the piping penetration and valve arrangement. The containment isolation valves, tubing, and piping (McGuire Unit 1 only) between them are safety related and within the scope of license renewal. The valves, tubing, and piping are passive, long-lived components that perform a pressure boundary function and are subject to aging management review. The aging management review results are presented in the table that follows.

The aging management review results for the Miscellaneous Instrumentation System components which include the hydrogen analyzers, integrated leak rate test connections, and containment radiation monitors are provided in the following table which supplements information provided in the Application.

Aging Management Review Results – Miscellaneous Instrumentation System

Component Type	Component Function (Note 1)	Material (Note 2)	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
Pipe (MNS only)	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Reactor Building	None Identified	None Required
Pipe (MNS only)	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Sheltered	None Identified	None Required
Tubing	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Reactor Building	None Identified	None Required
Tubing	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Sheltered	None Identified	None Required
Valve Bodies	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Reactor Building	None Identified	None Required
Valve Bodies	PB	SS	Ventilation (Note 3)	None Identified	None Required
			Sheltered	None Identified	None Required

Notes for Table, Aging Management Review Results – Miscellaneous Instrumentation System:

(1) Component Function

PB Maintain mechanical pressure boundary integrity so that sufficient flow and/or sufficient pressure are delivered, effect Containment isolation for fission product retention, or prevent physical interaction with safety-related equipment.

(2) Material

SS Stainless Steel

(3) The subject components are normally open to the Reactor Building ambient air (considered a ventilation environment for license renewal considerations).

RAI 2.3.2.3-3

The staff wishes to verify that the applicant has properly treated the containment hydrogen recombiners in the LRA. In the containment air return and hydrogen skimmer system diagrams for McGuire, MC-1557-1.0 and MC-2557-1.0, the hydrogen recombiners are shown but not highlighted as being within the scope of license renewal. In the containment air return and hydrogen skimmer system diagrams for Catawba, CN-1557-1.0 and CN-2557-1.0, the hydrogen recombiners are not shown, and thus are also not highlighted as being within the scope of license renewal. It appears to the staff that the containment hydrogen recombiners would meet the scoping criterion of 10 CFR 54.4(a)(1)(iii), and thus be within the scope of license renewal. It also appears possible that there may be recombiner components or components associated with the recombiners which could meet the screening criteria of 10 CFR 54.21 for an AMR.

Furthermore, based upon the treatment of the containment hydrogen recombiners in the drawings cited above and the fact that the recombiners are not described in the UFSAR section which concerns the containment air return and hydrogen skimmer systems for both McGuire and Catawba, the staff is uncertain as to which LRA section the applicant intended to include the containment hydrogen recombiners.

1. For both Catawba and McGuire, in which section of the LRA did the applicant include the containment hydrogen recombiners?

2. For both Catawba and McGuire, did the applicant determine the containment hydrogen recombiners to be within the scope of license renewal? If the applicant has determined the containment hydrogen recombiners to be outside the scope of license renewal, the staff additionally requests a justification for this considering the scoping criterion of 10 CFR 54.4(a)(1)(iii).

3. For both Catawba and McGuire, did the applicant determine any mechanical or electrical components to be subject to an AMR which are either part of or which support the operation of the containment hydrogen recombiners? Though it appears from the information in the UFSAR that the hydrogen recombination reaction may be accomplished through an active process, the staff wishes to verify that the applicant has properly considered any passive components which are necessary to support the operation of the containment hydrogen recombiners.

Response to RAI 2.3.2.3-3

The hydrogen recombiners for both McGuire and Catawba are Westinghouse/Sturtevant electrical hydrogen recombiners. These recombiners are electrical (versus mechanical) components, are included in the Environmental Qualification (EQ) Program at each site and are within the scope of license renewal. Electrical components included in the EQ program in accordance with §50.49 are replaced based on qualified life and are thus short-lived components. Because the hydrogen recombiners are short-lived, they do not meet the criteria of §54.21(a)(1)(ii), are not subject to an aging management review, and are not included in Section 3 of the Application.

2.3.2.6 Refueling Water System

RAI 2.3.2.6-1

Section 3.6.5.1.2 of the McGuire Updated Final Safety Analysis Report (UFSAR), and Section 3.6.1.1.3.1 of the Catawba UFSAR, credits refueling cavity walls as a barrier between reactor coolant loops and other vital equipment or piping to protect against the dynamic effects of a postulated pipe break (e.g., pipe whip, blowdown jet, etc.). Accordingly, the refueling cavity should be within the scope of license renewal because it is relied upon to mitigate the consequences of an accident. Drawings MCFD-1571-01.00, MCFD-2571-01.00, CN-1571-1.0 and CN-2571-1.0 are highlighted to indicate the portions of the refueling water system (FW) that are within the scope of license renewal for McGuire and Catawba. The McGuire unit 1 drawing indicates that the refueling cavity is not within the scope of license renewal. The McGuire unit 2 drawing, however, shows the refueling cavity as being within the scope of license renewal. Similarly, neither Catawba drawing indicates that the refueling cavity is within the scope of license renewal. Please explain which represents the applicant's position on whether the refueling cavity is within the scope of license renewal. If the refueling cavity is not within the scope of license renewal, please provide the basis for its exclusion considering the intended function cited in Section 3.6.5.1.2 of the Section 3.6.1.1.3.1 of the McGuire and Catawba UFSARs. If the refueling cavity is within the scope of license renewal, please explain where the AMR results for the refueling cavity are included in the LRA. [Note that the refueling cavity is not included in Table 3.2-6 of the application. This table provides the aging management review results for the FW system.]

Response to RAI 2.3.2.6-1

The refueling cavity is a structural component and is within the scope of license renewal. The refueling cavity is a poured-in-place reinforced concrete structure that is cast integrally with the reactor cavity wall, the crane wall, the operating floor and the base slab. It is lined on its inside face with stainless steel plates. The aging management review results for the refueling cavity are addressed in Table 3.5-1 of the Application (page 3.5-8, rows 2 and 6).

As clarification, highlighted flow diagrams show mechanical system evaluation boundaries. Structural components are generally not represented on flow diagrams, but in cases where they are, as in this case, the structural components are not addressed by the highlighting conventions.

RAI 2.3.2.6-2

As noted above, drawings MCFD-1571-01.00 and MCFD-2571-01.00 are highlighted to indicate the portions of the FW system that are within the scope of license renewal for McGuire, Units 1 and 2, respectively. During our review of these drawings, we identified two inconsistencies between the two units regarding the boundaries of piping/valves that are included within the scope of license renewal. Specifically,

1. On drawing MCFD-1571-01.00, the 3/4 inch system low point drain piping and associated valve 1FW0003 located at coordinates E-9 on the drawing are not shown as being within scope. The same piping and valve (2FW0003) on drawing MCFD-2571-01.00 are shown as being within the scope of license renewal.

2. On drawing MCFD-1571-01.00, the 3/4 inch test vent piping and associated valve 1FW0006 located at coordinates C-6 on the drawing are not shown as being within scope. The same piping and valve (2FW0006) on drawing MCFD-2571-01.00 are shown as being within the scope of license renewal.

It appears that in both cases, drawing MCFD-1571-01.00 may be incorrect. The drain and test vent piping and valves should be within scope to ensure the pressure boundary of the in scope FW system piping. Please verify that the drain and test connections cited above are within the scope of license renewal. If they are not within the scope of license renewal, please provide the basis for their exclusion.

Response to RAI 2.3.2.6-2

The drain and test connections associated with valves 1FW0003 and 1FW0006 are both 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 and valves for these drain and test connections are contained in Table 3.2-6 (page 3.2-36, row 2 and page 3.2-39, row 1) of the Application.

RAI 2.3.2.6-3

As noted above, drawings CN-1571-1.0 and CN-2571-1.0 are highlighted to indicate the portions of the FW system that are within the scope of license renewal for Catawba, Units 1 and 2, respectively. During our review of these drawings, we identified inconsistencies between regarding the boundaries of piping/valves that are included within the scope of license renewal. Specifically,

1. On drawings CN-1571-1.0 and CN-2571-1.0, the 3/4 inch system low point drain piping and associated valve (1FW3 for Unit 1 and 2FW3 for Unit 2) located at coordinates L-9 on both drawings are shown as not within the scope of license renewal.

2. On drawings CN-1571-1.0 and CN-2571-1.0, the 3/4 inch test drain piping and associated valve 1FW59 and 2FW59 located at coordinates L-4 on both drawings are shown as not within the scope of license renewal.

3. On drawing CN-2571-1.0, the vent piping and associated valve (2FW75) located at coordinates L-7 on the drawing are shown as not within the scope of license renewal. No equivalent vent is shown on the Unit 1 drawing, CN-1571-1.0.

4. On drawing CN-2571-1.0, the test vent piping and associated valve (2FW6) located at coordinates L-4 on the drawing are shown as not within the scope of license renewal. This test vent is shown as being within the scope of license renewal on the Unit 1 drawing, CN-1571-1.0.

5. On drawing CN-2571-1.0, the piping connection between the refueling water storage tank (RWST) and the safety injection (SI) and charging pump suction headers located at coordinates F-10 on the drawing is shown as not being within the scope of license renewal. This pipe connection to the SI and charging pump suction headers is shown as being within the scope of license renewal on the Unit 1 drawing, CN-1571-1.0.

6. The system high point vent piping and associated valve (2FW68) located at coordinates F-10 on the drawing are shown as not within the scope of license renewal. This pipe connection to the SI and charging pump suction headers and the vent are shown as being within the scope of license renewal on the Unit 1 drawing, CN-1571-1.0.

Typically, vent, test and drain piping connected to in scope piping systems are included in the scope of license renewal through the vent, test, or drain piping isolation valve as shown in several other locations on both drawings. It appears that in all of these cases, the piping and associated valves should be within scope to ensure the pressure boundary of the in scope FW system piping.

Please verify that the piping and valves cited above are within the scope of license renewal. If they are not within the scope of license renewal, please provide the basis for their exclusion.

Response to RAI 2.3.2.6-3

The vent, test and drain piping and valves described in items 1 through 6 in RAI 2.3.2.6-3 are all within the scope of license renewal and subject to aging management review. While the piping and valves are within the license renewal boundary defined by license renewal flags, highlighting was inadvertently left off these segments. The piping and valves associated with these vent, test and drain connections are contained in Table 3.2-6 (page 3.2-36, rows 2 and 3; page 3.2-38, row 2; page 3.2-39, row 1) of the Application.

RAI 2.3.2.6-4

Both drawings MCFD-1571-01.00 and MCFD-2571-01.00 show three piping connections between piping designated as being within the scope of license renewal (between the RWST and the refueling cavity) and 4 inch diameter piping to the spent fuel pool makeup (one piping connection) and refueling water pump suction and discharge (two piping connections) at coordinates E-8 and E-9 on both drawings. In the case of these three connections, there appears to be no physical boundary (i.e., a valve) separating the in scope piping from the piping that is not within scope. Accordingly, failure of these pipes could prevent the in scope piping from performing its intended function.

Similarly, both drawings CN-1571-1.0 and CN-2571-1.0 show two piping connections between piping designated as being within the scope of license renewal (between the RWST and the refueling cavity) and 4 inch diameter piping to the refueling water pump suction and 8 inch diameter piping from the discharge of the refueling water pump at coordinates J-12 on both drawings. In the case of these two connections, there appears to be no physical boundary (i.e., a valve) separating the in scope piping from the piping that is not within scope. Accordingly, failure of these pipes could prevent the in scope piping from performing its intended function.

Therefore, please provide the basis for not including these McGuire and Catawba FW system pipes within the scope of license renewal through the first shutoff valve on each pipe.

Response to RAI 2.3.2.6-4

The piping between valves 1FW4 and 1FW1A on drawings CN-1571-1.0 and MCFD 1571-1.0 are not within the evaluation boundaries for license renewal. License renewal boundary flags should have been placed at 1FW4 and 1FW1A, and the highlighting omitted from the piping between those valves. Likewise, the piping between valves 2FW4 and 2FW1A on drawings CN-2571-1.0 and MCFD 2571-1.0 are not within the evaluation boundaries for license renewal. License renewal boundary flags should have been placed at 2FW4 and 2FW1A, and the highlighting omitted from the piping between those valves.

RAI 2.3.2.6-5

According to the Catawba and McGuire UFSARs, the SI system is provided with a minimum flow bypass line from each pump discharge line to recirculate flow to the refueling storage tank in the event that the pumps are started during shutoff head conditions. This line prevents damage to the pump (e.g., warped vanes, damaged bearings, or binding of pump moving parts) that can occur due to rapid overheating of the water if the pump is operating against shutoff head conditions. If there are transients or design basis events (e.g., small loss-of-coolant accident) where the SI pumps may receive a start signal before reactor coolant system pressure is reduced to a low enough level for the safety injection pumps to provide flow, then it is logical to assume that the minimum flow piping is necessary to ensure that the SI pumps are capable of performing their intended function.

Drawings MCFD-1562-03.00 and MCFD-2562-03.00 show the portions of the SI that are designated as being within the scope of license renewal for McGuire, Units 1 and 2 respectively. The minimum flow line is only designated as being within scope through valve 1NI0147A for Unit 1 and 2NI0147A for Unit 2. The rest of the piping from that valve back to the RWST is designated as not being safety-related and is shown as not within the scope of license renewal.

Similarly, drawings CN-1562-1.2 and CN-2562-1.2 show the portions of the SI that are designated as being within the scope of license renewal for Catawba, Units 1 and 2 respectively. The minimum flow line is only designated as being within scope through valve 1NI147B for Unit 1 and 2NI147B for Unit 2. The rest of the piping from that valve back to the RWST is designated as not being safety-related and is shown as not within the scope of license renewal.

Please provide the basis for not including **all** of the minimum flow piping associated with the McGuire and Catawba SI pumps within the scope of license renewal.

Response to RAI 2.3.2.6-5

The safety related portions of the minimum flow piping associated with the McGuire and Catawba Safety Injection System pumps are within the scope of license renewal. The nonsafety-related portions of this line are not within the scope of license renewal, since they do not support any Safety Injection System intended function. Loss of pressure boundary of the nonsafety-related portion of the minimum flow piping does not adversely impact the ability to achieve minimum recirculation flow.

2.3.2.7 Residual Heat Removal System

RAI 2.3.2.7-1

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 the auxiliary spray is relied upon to mitigate design-basis events, or relied on in safety analyses or plant evaluations to perform a function that demonstrate compliance with the regulated events (e.g., fire protection and station blackout), then the staff requests the applicant to explain why the spray head (the component which actually sprays the water inside the pressurizer) need not require aging management to detect cracking and/or clogging of the spray holes, or any other aging related degradation over the extended period of operation. If the applicant believes that the intended function of the subject component to depressurize the system by spraying water inside the pressurizer is not within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) or (3), then the staff requests the applicant to affirm that the subject component in McGuire and Catawba units are not credited for immediate pressure reduction during design basis events, postulated fire events or station blackout.

Response to RAI 2.3.2.7-1

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 3.3-1 of the Application is supplemented with the following information:

Component Type	Component Function	Material)	Environment	Aging Effect	Aging Management Programs and Activities
Steam Generator					
Pressurizer Spray Head	Spray	Cast Stainless Steel	Borated Water	Cracking	Chemistry Control Pressurizer Spray Head Examination

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 assure 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 following summary description of the *Pressurizer Spray Head Examination:*

Pressurizer Spray Head Examination

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 thermal embrittlement.

Detection of Aging Effects – The *Pressurizer Spray Head Examination* is a one-time inspection will detect the presence of cracking due to thermal embrittlement for 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.

2.3.2.8 Safety Injection System

RAI 2.3.2.8-1

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 to be within scope that requires an AMR. Please explain why.

Response to RAI 2.3.2.8-1

The vortex suppressor is a sub-component of the recirculation intake sump screen assembly, is subject to aging management review and is addressed in Table 3.5-1 (page 3.5-9, row 3) of the Application. 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).

Attachment 3
Application to Renew the Operating Licenses of McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letter dated January 28, 2002

2.3.3.3 Building Heating Water System

RAI 2.3.3.3-1

The building heating 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) and are within the license renewal boundary. Catawba drawings CN 1606-1.0 (at J-14), CN 1606-1.6 (at J-3), CN 1606-1.7 (at J-7/8), CN 1606-1.8 (at J-5 and J-9), and CN-1606-1.9 (at K-14) indicate that the boundaries end in segments of pipe that are non-isolable and do not appear to coincide with structural boundaries (e.g., building walls). The staff questions the termination of Class F piping depicted on the license renewal drawings at locations other than building walls or valves. Please provide the function(s) that is (are) being protected from failure of the building heating water Class F piping at these locations and the nature of the postulated failure (e.g., pipe whip, flooding, etc.) so that the staff can confirm that the safety-related functions are being adequately protected considering the extent of the boundaries for the Class F pipe designations.

Response to RAI 2.3.3.3-1

As described in Section 2.1.1.2.1 of the Application, Duke Class F piping at McGuire and Catawba is nonsafety-related piping whose pressure boundary loss may adversely affect essential systems or equipment. Loss of pressure boundary of the Class F piping in the Building Heating Water System could be a flood concern for certain areas of the Auxiliary Building.

During design of 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. See the response to RAI 2.1-2.a and RAI 2.1-2.b in Attachment 4 of this letter.

The piping class breaks on the flow diagram are misleading. On CN 1606-1.0, the class break is shown at a flange inside the Auxiliary Building. A review of layout drawings indicates that the class break occurs on the Turbine Building side of the Auxiliary Building - Turbine Building wall. Of the other locations in question on the remaining flow diagrams, a review of layout drawings indicates that the class break occurs at the branch line tees, although the flow diagram would lead the reviewer to believe the class break is some distance down the small diameter piping. A corrective action report has been entered into the corrective action program to clarify the flow diagrams. The piping and valves associated with the Class F portions of these lines is contained in Table 3.3-3 (page 3.3-16, rows 1 through 3) of the Application.

2.3.3.5 Component Cooling System

RAI 2.3.3.5-1

For Catawba Unit 1, component cooling water (KC) pumps 1, 2, 3 and 4 on drawing CN-1573-1.0 contain license renewal boundary changes at what appear to be two 3/4" lines from each pump with an apparent class change (2 to 3) immediately adjacent to the pumps. Similarly sized lines for these pumps have boundary changes at the first valve. For Unit 2 drawing CN-2573-1.0, the analogous pipe segments are also not highlighted; however, these segments do not have a License Renewal Flag to indicate the boundary. What are the functions of these lines and why is it acceptable to have a boundary that is non-isolable (i.e., are these non-valved leak-off lines)?

Response to RAI 2.3.3.5-1

The non-highlighted pipe segments at the Component Cooling Water System pumps on drawing CN-1573-1.0 are stuffing box overflow lines. These lines do not support any system intended function and do not serve a pressure boundary function. The boundary flags on the Unit 1 drawing are correct and a similar set of boundary flags should have been shown on the analogous Unit 2 drawing CN-2573-1.0.

RAI 2.3.3.5-2

The Post Accident Liquid Sample Panel II+ cooler is depicted as outside the license renewal boundary on drawings CN-1573-1.0 and CN-2573-1.0. The KC pipe class changes to Class E (nonsafety-related; QA CONDITION 2 which is applied to systems designed to normally carry a radioactive fluid; however, they are considered non-nuclear safety systems, since a component failure would not result in a calculated potential exposure in excess of the limits established in 10 CFR 20) at the boundaries. However, failure of this piping would appear to prevent satisfactory accomplishment of the functions of 10 CFR 54.4(a) (prevention or the mitigation of an accident based on results obtained from the sample panel). Explain why these lines are not within scope of license renewal.

Response to RAI 2.3.3.5-2

Results from the nonsafety-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 Application that "eliminate the requirements to have and maintain the post-accident sampling systems." [References 1 and 2 below]

Reference 1: Chandu P. Patel (NRC) to G. R. Peterson (Duke), "Catawba Nuclear Stations, Units 1 and 2 Re: Issuance of Amendments (TAC Nos. MB2332 and MB2333)", September 11, 2001.

Reference 2: Robert E. Martin (NRC) to H. B. Barron (Duke), "McGuire Nuclear Station, Units 1 and 2 – Issuance of Amendments Re: Elimination of Post Accident Sampling Requirements (TAC Nos. MB2307 and MB2308)", September 17, 2001.

RAI 2.3.3.5-3

Note 9 on drawing CN-1573-1.1 states that "Crossover/overflow line connects near the top of each surge tank." Does this note apply separately to what appears to be a single crossover line (J-5 to J-10) and a single overflow line (I-5 to I-10) connecting KC Surge Tanks 1A and 1B? If so, and since the overflow line is depicted as outside the license renewal boundary, how can the crossover line fulfill its license renewal function if the overflow line is not intact? Also address the analogous situation for Catawba Unit 2, which is described in note 10 on drawing CN-2573-1.1.

Response to RAI 2.3.3.5-3

Note 9 on drawing CN-1573-1.1 applies only to the line shown at J-5 to J-10. As stated in the note, 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. This overflow line is not intended to be a cross-connect; the system is not designed assuming the tanks are cross-connected. This overflow line is within the scope of license renewal.

Note 9 on drawing CN-1573-1.1 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. Both tanks would have to be completely filled before water would flow through this line. With the tank pressures equalized, water would not flow through the loop seals from one tank to the other. The water would flow to the sump. This line is not required for the system to perform its function, which is why it is not safety-related. Likewise, because it taps off the top of the tank, its failure would not impact the ability of the system to perform its function. Since this line does not meet the license renewal scoping criteria, it is not within the scope of license renewal.

Note 10 on drawing CN-2573-1.1 is the same as Note 9 on CN-1573-1.1. The discussion above applies analogously to Unit 2.

RAI 2.3.3.5-4
Catawba Unit 1 Drawing CN-1573-1.2 depicts what appears to be a (non-highlighted) blank flange at coordinates G-2. Is this component within the license renewal boundary? If not, state the basis. If so, is there a stated convention for depicting such components on the license renewal drawings?

Response to RAI 2.3.3.5-4
The blank flange at coordinate G-2 on drawing CN-1573-1.2 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, row 4) of the Application.

RAI 2.3.3.5-5

Catawba Unit 1 and Unit 2 Drawings CN-1573-1.3 and CN-2573-1.3 identify that the KC coolers for the reactor vessel supports and associated piping are classified safety-related (line listing 01 and 37; both class C). Similarly, McGuire Unit 1 and Unit 2 Drawings MCFD-1573-03.01 and MCFD-2573-03.01 identify that the KC coolers for the reactor vessel supports and associated piping are classified safety-related (line listing 16 and 40; both class C). Why are these coolers and piping considered outside the scope of license renewal?

Response to RAI 2.3.3.5-5

The Component Cooling System (KC) coolers for the reactor vessel supports and associated piping are classified as safety-related (Duke Pipe Class C). This portion of the system, however, is not within the scope of license renewal because the coolers are no longer used and are isolated by administratively closed valves. Each McGuire drawing contains a note (Note 8 on MCFD-1573-3.1 and Note 11 on MCFD-2573-3.1) at the closed valves that explains that flow is isolated from the coolers. The Catawba drawings do not contain a note, but the same situation exists at Catawba. 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.

RAI 2.3.3.5-6

Catawba Unit 2 Drawing CN-2573-1.3 appears to have been erroneously drafted omitting the highlighting to depict the reactor coolant drain tank heat exchanger as within the scope of license renewal. The similar heat exchanger for Unit 1 on drawing CN-1573-1.3 is within scope; and Table 3.3-7 Aging Management Review Results – Component Cooling System, has appropriate entries for the reactor coolant drain tank heat exchanger. Please confirm above understanding of the correct boundary highlighting.

Response to RAI 2.3.3.5-6

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. As pointed out in RAI 2.3.3.5-6, the reactor coolant drain tank heat exchanger is included in Table 3.3-7 (page 3.3-77, rows 3 and 4; page 3.3-78, row 1) of the Application.

RAI 2.3.3.5-7
Catawba Unit 1 and Unit 2 Drawings CN-1573-1.4, CN-1573-1.7, CN-2573-1.4, and CN-2573-1.7 have indications that are unclear to the reviewer (not explained in the drawings for flow diagrams) for the various reactor coolant pump motor coolers and thermal barriers. Confirm whether these (D, E, H, I, J, K, and U) are bolted connection points or some other component.

Response to RAI 2.3.3.5-7
Indications (D, E, H, I, J, K, and U) for the various reactor coolant pump motor coolers and thermal barriers are references to connection details on manufacturer's outline drawing(s). These connections could either be bolted or welded as specified in the original design documents.

RAI 2.3.3.5-8

Note 5 on Catawba Unit 1 and Unit 2 Drawings CN-1573-1.4, CN-1573-1.7, CN-2573-1.4, and CN-2573-1.7, indicates that the reactor coolant pump upper motor bearing cooler connection "T" on the top of the bearing cooler should be plugged. It appears there is no listing on Table 3.3-7 Aging Management Review Results – Component Cooling System corresponding to this plug. A plug valve is discussed in Table Note 4, but this appears to correlate to valve 1KC401 (as well as other valves), which is described as a valve inside the oil enclosure. Address why this plug is not subject to an AMR for its apparent pressure boundary intended function, or clarify the discussion in table.

Response to RAI 2.3.3.5-8

The reactor coolant pump upper motor bearing cooler shell nozzles shown on the flow diagrams listed in RAI 2.3.3.5-8 are labeled "J", "K", "T", and "U". Note 5 on these drawings indicates that connection "T" is plugged. The nozzle is plugged because it is not used. 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, row 4) of the Application.

RAI 2.3.3.5-9
It is unclear how temperature elements in pipe segments that are within scope of license renewal have been addressed. For example, Catawba Unit 1 and Unit 2 Drawings CN-1573-1.4, CN-1573-1.7, 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 within scope of license renewal. The thermowells for these temperature elements are not highlighted nor are the wells or temperature elements included within Table 3.3-7, Aging Management Review Results – Component Cooling System. Section 2.5 Scoping And Screening Results: Electrical And Instrumentation And Controls, notes that the pressure boundary function associated with RTDs and thermocouples is included in the process of identifying the mechanical pressure boundaries and is included in the applicable mechanical reviews within the application (e.g., Sections 2.3, 3.1, 3.2, 3.3, and 3.4).

Similarly for McGuire, Drawing MCFD-573-02.02 depicts temperature transmitters (1KCTX5340 and 1KCTX5380) in piping within scope of license renewal. It is not clear whether these instruments are located in thermowells or whether there are wells included within Table 3.3-6, Aging Management Review Results – Component Cooling System.

For both stations, clarify whether these are wells or temperature elements and whether they are within scope for pressure boundary intended function. If wells are used, address whether the heat transfer intended function should be subject to an aging management review.

Response to RAI 2.3.3.5-9
On the McGuire and Catawba mechanical flow diagrams, the instrument nomenclature identifies whether the temperature element is installed in a thermowell. For example, the letters "TE" in the component identification number 1KCTE5880 would indicate that a temperature element is installed in the thermowell. The letters "TX" in the component identification number 1KCTX5880 would indicate that no temperature element is installed in the thermowell. In this example, a 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 commodity type "Pipe" or "Piping" is used throughout the Application 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.

For thermowells, pressure boundary is the only component intended function. An understanding of the heat transfer design aspects can be gained from Appendix C of NEI 95-10 (Revision 3). 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 aging management review for license renewal. For thermowells, heat transfer is a secondary function and does not need to be the focus of the aging management review. Therefore, pressure boundary is the only component intended function of thermowells.

RAI 2.3.3.5-10
It is unclear if several interfacing components, depicted on Catawba Unit 1 and Unit 2 Drawings CN-1573-2.2, CN-1573-2.3, CN-2573-2.2, and CN-2573-2.3, that are cooled by KC are considered within or outside the scope of license renewal. These components (from drawing CN-1573-2.2, analogous components on other drawings) include various pump oil coolers (e.g., the safety injection pump bearing; the centrifugal charging pump speed reducer; and the centrifugal charging pump bearing). These components interface with vendor supplied oil. Please confirm that there is no separate system (pump and tubing) that circulates the oil through the pump coolers. If there is a separate oil system that performs this function, please indicate if that system is within the scope of license renewal and subject to an AMR.

Response to RAI 2.3.3.5-10
No separate system circulates the oil through the various pump oil coolers identified in RAI 2.3.3.5-10. The vendor supplied oil indicated on the drawings in question is simply an oil bath that is part of the pump motor.

RAI 2.3.3.5-11

For McGuire Unit 1 drawing MCFD-1573-01.01, explain why vacuum breaker 1KC0123 (at I-5) for the component cooling surge tank and the associated pipe segment are not depicted in scope of license renewal. It would appear that protection from vacuum conditions is an intended function, considering the tank can be automatically isolated from vent path. The similar vacuum breaker for McGuire Unit 2 is shown on drawing MCFD-2573-01.01 to be within scope.

Response to RAI 2.3.3.5-11

The vacuum breaker 1KC0123 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 contained in Table 3.3-6 (page 3.3-53, row 5; page 3.3-55, row 5) of the Application.

RAI 2.3.3.5-12

For McGuire Unit 1 drawing MCFD-1573-02.00, it appears that vent valve 1KC0884 (at C-10) and associated 1" line were erroneously not depicted in scope of license renewal for pressure boundary intended function. Please confirm or explain why these are not in scope.

Response to RAI 2.3.3.5-12

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 piping and vent valve are contained in Table 3.3-6 (page 3.3-54, row 1; page 3.3-56, row 1) of the Application.

RAI 2.3.3.5-13

For drawings MCFD-1573-03.00 and MCFD-2573-03.00, clarify the status of flow transmitters and associated instrument lines for the reactor coolant pump motor upper bearing coolers. These are noted as abandoned in place; however most (6 of the 8 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 in general these lines are not flagged. Are the instruments/lines in question included in scope for pressure boundary intended function?

Response to RAI 2.3.3.5-13

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 aging management review in accordance with §54.21(a)(1)(i). The tubing is listed in Table 3.3-6 (page 3.3-55, row 2) in the Application.

2.3.3.6 Condenser Circulating Water System

RAI 2.3.3.6-1

Section 10.4.5.1 of the McGuire UFSAR notes that the condenser circulating water (RC) system is designed to use water from Lake Norman to remove rejected heat from the main and feedwater pump turbine condensers and other selected plant heat exchangers. It also serves as the normal supply for the conventional low pressure service water system and the fire protection system jockey pumps and a secondary supply for the nuclear service water (RN) system. However, the LRA notes that the RC system provides a suction source of water for the turbine driven auxiliary feedwater pump, and does not mention an intended function for the fire protection jockey pump or the secondary supply for the RN system mentioned above.

Why are the secondary supply to the RN system and/or the supply to the fire protection system jockey pumps not considered to be intended functions of the RC system? If these connections are on other drawings please provide the reference.

Response to RAI 2.3.3.6-1

The Condenser Circulating Water (RC) System only serves as a backup supply to the Nuclear Service Water (RN) System and does not meet any of the scoping criteria of 10 CFR 54.4. The Condenser Circulating Water System backup supply to the Nuclear Service Water System 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 §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 secondary supply to the jockey pumps is also not an intended function of the RC system. See response to RAI 2.3.3.19-6 (this Attachment) for more information on scoping of the jockey pump with respect to §54.4(a)(3).

RAI 2.3.3.6-2
Is the path(s) to supply water from the RC system to the turbine driven auxiliary feedwater pump through the two connections to the RN system discharge headers which are shown on drawing MCFD-1604-01.02 (C-7), with a continuation of the license renewal boundaries noted on the drawing? If not, where is this suction source provided and depicted on the RC system license renewal drawings?

Response to RAI 2.3.3.6-2
The path to supply water from the Condenser Circulating Water (RC) System to the Unit 1 Turbine Driven Auxiliary Feedwater Pump (TDCAP) is through the Nuclear Service Water (RN) System discharge header A that is shown on MCFD 1604-01.02 at coordinates C-7. The path to the Unit 2 TDCAP is through the RN System supply header B that is shown at G-11, with continuation of the license renewal evaluation boundaries noted on the drawing.

RAI 2.3.3.6-3
Are the connections for the RN system shown on drawing MCFD-1604-01.02 (C-7) intended to provide a path for discharge of water as an intended function? If so, clarify how this function is provided by the RC system.

Response to RAI 2.3.3.6-3
The license renewal evaluation boundaries shown on the connections for the Nuclear Service Water (RN) 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.

RAI 2.3.3.6-4
According to all three McGuire flow diagrams reference in the LRA for the RC 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. Does the basis of these boundaries relate to a particular volume of water that is contained within the piping? If not, state the basis for identifying the license renewal boundary at locations that are not isolable by a valve. If so; provide isometric drawings or calculations which depict where/how the water is entrapped for its intended function to allow verification that the boundaries have been correctly shown on the LRA drawings.

Response to RAI 2.3.3.6-4
The license renewal boundaries correspond to the Safe Shutdown System boundaries for the Condenser Circulating Water (RC) system. These boundaries approximate a volume of water that is credited as the auxiliary feedwater suction source for a fire and station blackout event.

McGuire calculation, MCC-1223.42-00-0003, "Determine Water Available for Secondary Side Makeup During a Security Event," Revision 3, that determines the available inventory required for postulated events was reviewed during a recent NRC inspection. McGuire Nuclear Station - NRC Inspection Report 50-369/01-06, 50-370/01-06 dated February 26, 2002 indicates that this calculation along with other design documents were reviewed and no findings were identified. Additionally, the same NRC inspector who reviewed the calculation driving the above inspection also participated in the McGuire and Catawba license renewal scoping and screening inspection that occurred in March 2002. The inspector recalled the water inventory issue and his review of the calculation. Based on his reviews for both inspections, he was satisfied with the license renewal evaluation boundaries as depicted on the flow diagrams.

RAI 2.3.3.6-5

For drawings CN-1604-1.0 and CN-2604-1.0, clarify whether the non-highlighted 4" drain lines on the suction of the Catawba RC pumps up to the discharge of the drain valves (e.g., 1RC34) are included in license renewal scope. The drawing convention states that vents and drains attached to license renewal piping are within scope unless otherwise indicated, and that license renewal flags are not shown in general. For example, on the same drawing, the 4" vent lines on the circulating water pump casings are depicted as within license renewal scope (by highlighting) up to the valve discharge, even though a license renewal flag is not drawn at that point. If these drain lines are not within scope, please address how the pressure boundary intended function is satisfied.

Response to RAI 2.3.3.6-5

The 4" drain lines on the suction of the Catawba Condenser Circulating Water (RC) System pumps up to the discharge of the drain valves (e.g., 1RC34) 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 contained in Table 3.3-8 (page 3.3-84, row 2; page 3.3-85, row 4) of the Application.

RAI 2.3.3.6-6
The expansion joints (2RC7, etc.) on the discharge of the condenser circulating water pumps are highlighted in red for Catawba Unit 2 on drawing CN-2604-1.0. The similar joints (1RC7, etc.) are just depicted as within the license renewal boundary without a highlight change on Catawba Unit 1 drawing CN-1604-1.0. Is there a significance to the highlight change for these expansion joints between units? Why aren't expansion joints listed as a component subject to aging management review in Table 3.3-8 Aging Management Review Results – Condenser Circulating Water System (Catawba only)?

Response to RAI 2.3.3.6-6
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 Application. Table 3.3-8, Aging Management Review Result – Condenser Circulating Water System (Catawba only), is supplemented with the following entry:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
Expansion Joints	PB	Synthetic Rubber*	Raw Water	None Identified	None Required
			Yard	None Identified	None Required

* A woven polyester and/or nylon fabric coated with chlorobutyl rubber.

RAI 2.3.3.6-7

Why are license renewal boundary flags placed on the suction and discharge flanges of the RC pumps? The pump casings are depicted as within scope on both Catawba Unit 1 drawing CN-1604-1.0 and Catawba Unit 2 on drawing CN-2604-1.0; however, the flags point in different directions on these drawings. Pump casings are listed as subject to aging management review in Table 3.3-8 Aging Management Review Results – Condenser Circulating Water System (Catawba only). The attached piping is highlighted as within scope for both units.

Response to RAI 2.3.3.6-7

The Condenser Circulating Water (RC) System pumps are within the scope of license renewal. No flags should have been placed at the inlet and discharge of the RC pumps.

RAI 2.3.3.6-8

Please confirm that the license renewal boundary flag at coordinates C-4 on Catawba Unit 1 drawing CN-1604-1.2 is apparently erroneously single-sided. (The continuation on drawing CN-1592-1.0 remains within license renewal scope).

Response to RAI 2.3.3.6-8

The license renewal flag at coordinate C-4 on Catawba drawing CN-1604-1.2 was inadvertently shown as single-sided instead of double-sided. The continuation to CN-1592-1.0 is within the scope of license renewal.

RAI 2.3.3.6-9

Section 10.4.5.3 of the McGuire UFSAR addresses flooding of the Turbine Building from failure of the circulating water system. A failure of the expansion joint at the condenser connection to the cooling water pipe is considered in the design. The UFSAR notes that the flooding analyses credit reduced clearance of the expansion joint, together with curbs 1.25 feet high at all openings to the Auxiliary Building, to contain this flood water in the Turbine Building basement. This expansion joint design and curbing provides 40.2 minutes of storage in the Unit 1 Turbine Building basement and allows time for action to be taken to control the flooding while protecting safety related equipment in the Auxiliary Building from this potential flood level. Why aren't the circulating water system expansion joints and the Turbine Building basement curbs protecting the openings to the Auxiliary Building within the scope of license renewal in accordance with 10 CFR 54.4 paragraph (a)(2)?

Response to RAI 2.3.3.6-9

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. The structures and components that mitigate this event are 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, row 3). In addition to flood curbs being a water-tight feature, flood seals along the wall of all in-scope structures are also within the scope of license renewal and are subject to an aging management review. Flood seals are addressed in Table 3.5-2 (page 3.5-16, row 4).

RAI 2.3.3.6-10

Catawba UFSAR section 10.4.5.3 notes that the maximum water level due to a simultaneous failure of the KC systems on both units and the subsequent draining of all water in the two closed loop cooling systems back to their respective Turbine Buildings will result in a maximum water elevation of 576.95'. All penetrations and passageways from the Turbine or Service Buildings to the Auxiliary Building are stated to be watertight to EL. 577.5', which will protect safety-related equipment from failure of the KC system. Have the water-tight 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)?

Response to RAI 2.3.3.6-10

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, row 3).

Flood seals are addressed in Table 3.5-2 (page 3.5-16, row 4).

Flood doors are addressed in Table 3.5-2 (page 3.5-13, row 4).

2.3.3.8 Chilled Water Systems

RAI 2.3.3.8-1

McGuire Nuclear Station LRA drawing MCFD-1618-01.00 depicts two Airtrol tank fittings at coordinates J-2 and C-2 as within the scope of license renewal. Catawba Nuclear Station LRA drawings CN-1578-2.0 and CN-1578-2.2 each depict an Airtrol fitting at coordinates B-11. However, Tables 3.3-9 and 3.3-10, Aging Management Review Results – Control Area Chilled Water System, do not have explicit entries corresponding to these tank fittings, although there are entries for piping and air tanks. Please explain or add to the AMR Tables.

Response to RAI 2.3.3.8-1

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 (page 3.3-97, rows 3 and 4, page 3.3-98, rows 1 and 2) and in Table 3.3-10 (page 3.3-108, rows 4 and 5; page 3.3-109, rows 1 and 2) of the Application.

RAI 2.3.3.8-2

The vent and drain lines on Control Area Chilled Water (YC) Pump P-1 up to valves 1YC0011 and 1YC0012 (McGuire Nuclear Station LRA drawing MCFD-1618-01.00 - L-7) appear to have been erroneously not highlighted as within license renewal scope, based on the drawing note on license renewal flags and the highlighting shown on drawing for YC Pump P-2. Several other segments of valved vent lines on this drawing appear to have erroneously omitted the license renewal highlighting (1YC0070 and 1YC0059 coordinates E-13 and J-7). Please confirm the correct boundaries.

Response to RAI 2.3.3.8-2

The vent and drain lines on Control Area Chilled Water (YC) System pump P-1 up to valves 1YC0011 and 1YC0012 and 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 contained in Table 3.3-9 (page 3.3-96, row 3; page 3.3-98, row 1) of the Application.

RAI 2.3.3.8-3

The compressors are depicted as within license renewal scope on LRA drawings MCFD-1618-04.00 (at G-4 and G-11), and CN-1578-2.4 and CN-1578-2.5 (at H-7). Why are there no entries for the YC compressor shells or cases in Tables 3.3-9 and -10, Aging Management Review Results – Control Area Chilled Water System for McGuire and Catawba?

Response to RAI 2.3.3.8-3

The compressors are within the scope of license renewal, but are not included in the aging management review results tables in the Application. Compressors, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight compressor exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

RAI 2.3.3.8-4
Two refrigerant lines for YC Chiller C-1 (between the condenser and the economizer and between the compressor and the oil cooler), appear to have been erroneously omitted from license renewal scope on LRA drawing MCFD-1618-04.00. Please confirm these lines are within scope.

Response to RAI 2.3.3.8-4
The two refrigerant lines for Control Area Chilled Water (YC) System chiller C-1 (between the condenser and the economizer and between the compressor and the oil cooler) 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 contained in Table 3.3-9 (page 3.3-96, row 1) of the Application.

RAI 2.3.3.8-5
On LRA drawing MCFD-1618-04.00, there appear to be two in-line flow indicators that are within the license renewal boundaries, but which don't have tag numbers placed as indicated on the P&ID symbols drawings (E-5, E-11). Although flow indicators are listed in Table 3.3-9, Aging Management Review Results – Control Area Chilled Water System (McGuire Nuclear Station), please confirm whether or not these particular items are flow indicators that are included in the aging management review results.

Response to RAI 2.3.3.8-5
The flow indicators on MCFD-1618-04.00, shown at E5 and E11 without tag numbers, are the flow indicators that are included in the aging management review results in Table 3.3-9 (page 3.3-95, row 3) of the Application.

RAI 2.3.3.8-6

Catawba Nuclear Station Control Area Chilled Water System LRA drawings CN-1578-2.0, 2.1, 2.2, 2.3, 2.4 and 2.5 each depict one or more thermowells installed within segments of piping that are within the scope of license renewal. However, the thermowells themselves are not highlighted, nor are there any entries in Table 3.3-10, Aging Management Review Results – Control Area Chilled Water System, corresponding to thermowells. Please confirm that these thermowells are within scope for license renewal. Address whether the thermowells should be included for aging management review of their heat transfer component function in addition to pressure boundary. Confirm that thermowells are not used in the McGuire control area chilled water system, or address their use and treatment for license renewal intended function.

Response to RAI 2.3.3.8-6

Thermowells are a part of the piping commodity listed in Table 3.3-6 (pages 3.3-52 though 3.3-54) and in Table 3.3-7 (pages 3.3-78 through 3.3-80) of the Application. Component identification numbers such as 0VCTH5350 indicate that a temperature element or thermometer is installed in a thermowell. Pressure boundary is the only component intended function of the thermowells. Also see the response to RAI 2.3.3.5-9 and Appendix C of NEI 95-10 (Revision 3).

RAI 2.3.3.8-7
Catawba Nuclear Station Control Area Chilled Water System LRA drawings CN-1578-2.0, -2.1, -2.2 and -2.3 all have a note which states "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 YC system two-way valves which would bypass flow from the fan coolers if in the alternate position (e.g., valves 1YC58 and 1YC26 on drawing CN-1578-2.0 at E-5 and E-12).

It would appear that these valves are passive devices held in the intended position by the springs. Address why these springs are not be subject to an AMR to ensure they retain the ability to maintain the position and passive nature of these valves. Alternatively, provide a basis for why these components are considered active and not subject to an AMR.

Response to RAI 2.3.3.8-7
All valve components (actuators, operators, disks, stems, springs, etc.) except for valve bodies are excluded from aging management review in accordance with §54.21(a)(1)(i).

RAI 2.3.3.8-8
Why isn't the tubing to (apparent) back-pressure regulating valves 1YC116 and 1YC72, shown on drawings CN-1578-2.0 and -2.2 (at D-11), depicted as within the scope of license renewal for pressure boundary function?

Response to RAI 2.3.3.8-8
Valves 1YC116 and 1YC72 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 aging management review. 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 contained in Table 3.3-10 (page 3.3-107, row 3; page 3.3-108, row 3; page 3.3-109, rows 1 and 2) of the Application.

2.3.3.10 Diesel Building Ventilation System

RAI 2.3.3.10-1

McGuire plant flow diagram, MC-1579-1, for the diesel building ventilation system indicates the diesel building normal heating coils are within the scope of license renewal. McGuire plant flow diagram, MC-2579-1 for the diesel building ventilation system indicates the diesel building normal heating coils are not within the scope of license renewal. Include the diesel building normal heating coils in the scope of license renewal on flow diagram MC-2579-1 and identify where in the LRA is the AMR for the diesel building normal heating coils or provide a justification for excluding these coils from Table 3.3-13 and an AMR.

Response to RAI 2.3.3.10-1

Highlighting on flow diagram MC-2579-1 should have included the diesel building normal heating coils, indicating that they are within the scope of license renewal. The duct-mounted electrical heating elements do not have a pressure boundary function or any other component intended function for license renewal. They are, therefore, not subject to an aging management review and are not included in Table 3.3-13.

2.3.3.11 Diesel Generator Engine Air Intake and Exhaust System

RAI 2.3.3.11-1

McGuire drawings MCFD-1609-05.00 and MCFD-2609-05.00 depict the portions of the diesel generator engine air intake and exhaust system that are within the scope of license renewal. These drawings indicate that the diesel generator air intake manifold, exhaust manifold, and turbo chargers are within the scope of license renewal. The passive portions of these components (e.g., turbo charger housing, etc.) have a pressure boundary intended function, however, they do not appear to be included in Table 3.3-14 as components subject to aging management review (AMR).

Similarly, Catawba drawings CN-1609-5.0 and CN-2609-5.0 depict the portions of the diesel generator engine air intake and exhaust system that are within the scope of license renewal for Catawba, Units 1 and 2, respectively. These drawings indicate that the diesel generator air intake manifold, exhaust manifold, and turbo chargers are within the scope of license renewal. The passive portions of these components (e.g., turbo charger housing, etc.) have pressure boundary intended functions, but are not included in Table 3.3-14 as components subject to AMR.

Please explain where these components are addressed in the application. If these components were not considered to be subject to an AMR, please provide the basis for this conclusion.

Response to RAI 2.3.3.11-1

The diesel engine air intake manifold, exhaust manifold, and turbochargers are subcomponents of the diesel engine. Diesel engines are a subcomponent of diesel generators. Diesel generators are not included in the aging management review results tables in the Application. Diesel generators, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

As a result, the air intake manifold, exhaust manifold, and turbocharger are within the scope of license renewal as subcomponents of the diesel generator, but are not subject to an aging management review and, therefore, not listed in Table 3.3-14 of the Application.

2.3.3.12 Diesel Generator Engine Cooling Water System

RAI 2.3.3.12-1

The staff reviewed the list of components identified as being subject to an AMR in Table 3.3-15 of the application, and compared the list with the passive long lived components identified as being within the scope of license renewal on McGuire drawings MCFD-1609-01.00, MCFD-1609-01.01, MCFD-2609-01.00, and MCFD-2609-01.01. The staff identified two passive, long-lived components identified on the drawings as being within the scope of license renewal that were not identified as being subject to an AMR in Table 3.3-15. These components are the turbo charger turbine cooling supply/return (e.g., heat exchanger tubes) and the flexible hose (located at coordinates K-4 on the drawings). Both of these components have pressure boundary intended functions. Please explain how these components are addressed in the application, or provide the basis for not subjecting them to an AMR.

Response to RAI 2.3.3.12-1

The turbocharger turbine cooling supply/return lines are subject to an aging management review and are included within the "Piping" entry in Table 3.3-15 (page 3.3-124) of the Application. These lines connect to the turbocharger portion of the diesel engine. (Note that no heat exchanger tubes exist for the turbocharger turbine.)

In accordance with §54.21(a)(1)(i), components replaced based on a qualified life are exempt from an aging management review. The flexible hose is replaced during the periodic maintenance on the diesel engine, and therefore, not subject to an aging management review. As a result, the flexible hose is not listed in Table 3.3-15 of the Application.

RAI 2.3.3.12-2

Catawba drawings CN-1609-1.0 and CN-2609-1.0 depict the portions of the diesel engine cooling water system that are within the scope of license renewal for Catawba, Units 1 and 2, respectively. These drawings indicate the turbo charger aftercoolers and engine jacket are within the scope of license renewal. The passive portions of these components (e.g., turbo charger housing, tubes, etc.) have pressure boundary intended functions, but are not included in Table 3.3-16 as components subject to AMR. Please explain where these components are addressed in the application. If these components were not considered to be subject to an AMR, please provide the basis for this conclusion.

Response to RAI 2.3.3.12-2

The turbocharger aftercoolers and engine jacket are subcomponents of the diesel engine. Diesel engines are a subcomponent of diesel generators. Diesel generators, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

As a result, the turbocharger aftercoolers and engine jacket are within scope but not subject to an aging management review. Therefore, the turbocharger aftercoolers and engine jacket are not listed in Table 3.3-16 of the Application.

2.3.3.13 Diesel Generator Crankcase Vacuum System

RAI 2.3.3.13-1

McGuire drawings MCFD-1609-06.00 and MCFD-2609-06.00 depict the portions of the diesel generator engine crankcase vacuum system that are within the scope of license renewal. These drawings indicate that there are two flexible hose connections on either side of the diesel generator crankcase vacuum blower that are within the scope of license renewal. The components are passive and should have a pressure boundary intended function, however, they do not appear to be included in Table 3.3-17 as components subject to aging management review (AMR). Please explain how these components are addressed in the application, or provide the basis for not subjecting them to an AMR.

Response to RAI 2.3.3.13-1

The synthetic rubber flexible expansion joints located at the inlet and outlet connections on the diesel generator engine crankcase vacuum blower are replaced during the periodic maintenance on the diesel engine. Therefore, the expansion joints are not considered long-lived components, are not subject to an aging management review in accordance with §54.21(a)(1)(ii), and are not included in Table 3.3-17.

RAI 2.3.3.13-2
Catawba drawings CN-1609-6.0 and CN-2609-6.0 depict the portions of the diesel generator engine crankcase vacuum system that are within the scope of license renewal. The Catawba UFSAR does not provide any written description of this system. It is not apparent from the drawings how this system accomplishes its intended function of reducing the concentration of combustible gases in the crankcase. As a result, the staff is unable to determine if all inscope, passive, long-lived components have been adequately captured for AMR. For instance, the drawings do not show a blower, nor is one listed for Catawba in Table 3.3-17 (the table of components determined by the applicant to be subject to an AMR). The staff notes that it is not uncommon for this type of system to utilize a vacuum blower. Without an explanation of how the system performs its intended function, the staff cannot determine whether no blower is listed in Table 3.3-17 because of how the system is designed or because of an inadvertent oversight by the applicant. Accordingly, please provide an explanation as to how this system performs its safety function.

Response to RAI 2.3.3.13-2
During normal diesel operation, the crankcase is ventilated by natural flow to the atmosphere, outside the Diesel Building, through a vent pipe which penetrates the Diesel Building roof. Pressure in the crankcase, induced by piston blow-by, is normally about 2 to 3 inches of water and creates the natural flow. The components within the scope of license renewal in the Diesel Generator Engine Crankcase Vacuum System as shown on Catawba drawings CN-1609-6.0 and CN-2609-6.0 are correctly depicted. No blower exists in the system.

2.3.3.14 Diesel Generator Fuel Oil System

RAI 2.3.3.14-1

McGuire drawings MCFD-1609-03.00, MCFD-1609-03.01, MCFD-2609-03.00 and MCFD-2609-03.01 depict the portions of the diesel generator fuel oil system that are within the scope of license renewal. These drawings indicate that there are flexible hose connections on either side of the diesel generator engine that are within the scope of license renewal. The components are passive and should have a pressure boundary intended function, however, they do not appear to be included in Table 3.3-18 as components subject to AMR. Please explain how these components are addressed in the application, or provide the basis for not subjecting them to an AMR.

Response to RAI 2.3.3.14-1

The flexible hose connections located on either side of the diesel generator engine are replaced during the periodic maintenance on the diesel engine. Therefore, the flexible hose connections are not considered long-lived components, are not subject to an aging management review in accordance with §54.21(a)(1)(ii), and are not included in Table 3.3-18.

RAI 2.3.3.14-2

The McGuire diesel generator engines are equipped with features that collect leaking fuel oil and route it to the used oil storage tank. Specifically, Section 9.5.4.2 of the McGuire UFSAR states, "A diesel fuel oil drain header is located on each side of the engine. These headers are connected by individual pipes to cavities in the cylinder heads and in the injection pump deck of the frame. Oil leaking past the plunger and barrel of the injector pump and past the fuel injector spring seat returns through these lines to the drip tank. From here the oil is routed to the used oil storage tank." The intended function of this oil collection feature is not specifically stated; however, in general, oil collection systems function to ensure that leaking oil will not lead to a fire that could damage safety-related equipment. This intended function appears to meet scoping the criteria of 10 CFR 54.4(a)(2) or 10 CFR 54.4(a)(3). As stated above, McGuire drawings MCFD-1609-03.00, MCFD-1609-03.01, MCFD-2609-03.00 and MCFD-2609-03.01 depict the portions of the diesel generator fuel oil system that are within the scope of license renewal. Drawings MCFD-1609-03.00 and MCFD-1609-03.01 do not show the fuel oil collection system as being within the scope of license renewal. Drawings MCFD-2609-03.00 and MCFD-2609-03.01, however, show a portion of the piping for the fuel oil collection system as being within the scope of license renewal. The boundary of the inscope portion of the piping is not clearly defined. If the applicant determined during the preparation of their license renewal application (LRA) that the fuel oil leakage collection piping is within the scope of license renewal, then please provide a clarification as to the extent to which the piping and components (e.g., diesel generator fuel oil drip tank, diesel generator fuel oil drip tank pump, etc.) are within the scope of license renewal, and the basis for the boundary. If the applicant determined that the fuel oil leakage collection system is not within the scope of license renewal, then please provide the basis for this conclusion given the potential fire hazard that could be created if this system failed.

Response to RAI 2.3.3.14-2

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 "21," this highlighting inconsistency between the McGuire Unit 1 and 2 drawings does not represent a physical difference in scope. The connection point is on the diesel engine. Both drawings indicate that the license renewal evaluation boundary is at the connection point of the fuel oil leakage collection components to the diesel engine.

The diesel engines have a feature that collects fuel oil leaking past the plunger and barrel of the injector pump and past the fuel injector spring seat and transports it through piping to a drip tank and on to the used oil storage tank. The piping and components (e.g., diesel generator fuel oil drip tank, diesel generator fuel oil drip tank pump, etc.) associated with this feature are not within the license renewal evaluation boundaries because they do not perform a function that meets the criteria of §54.4. The components are not safety-related and do not perform any function to meet §54.4(a)(1). Their failure will not prevent the accomplishment of a safety-related function and therefore do not meet §54.4(a)(2). Further, this feature is not credited to meet any of the Commission's regulations specified in §54.4(a)(3). Separate fire barriers and fire suppression is provided for compliance with §50.48. Therefore, the license renewal evaluation boundary is at the diesel engine as described above.

RAI 2.3.3.14-3

Catawba drawings CN-1609-3.0, CN-1609-3.1, CN-2609-3.0 and CN-2609-3.1 depict the portions of the diesel generator fuel oil system that are within the scope of license renewal. These drawings show the fuel oil day tank retaining wall as not within the scope of license renewal. However, the Catawba UFSAR provides descriptions of the intended functions of this wall. For instance, Section 9.5.4.3 of the Catawba UFSAR states the retaining wall is a fire barrier protecting the fuel oil day tank. Section 7.6.15.1 of the UFSAR further states that the retaining wall serves as a containment for any leakage from the day tank, and the level in the retaining wall is alarmed to the control room to alert operators to an abnormal operating condition (i.e., excessive leakage). It appears from the UFSAR that the fuel oil day tank retaining wall meets the criteria of 10 CFR 54.4(a)(2) [and possibly 10 CFR 54.4(a)(3)], and therefore, should be included within the scope of license renewal. Please provide either the basis for not including the retaining wall within the scope of license renewal, or an explanation as to where the application addresses this structure.

Response to RAI 2.3.3.14-3

The diesel fuel oil day tank at Catawba is located within the emergency diesel generator room, which is separated from other plant areas by three-hour fire-rated barriers. Each diesel fuel oil day tank is surrounded by a retaining wall that is approximately 5 feet in height. The walls extend above piping to the tank to block oil spray from the diesel generator room. The fuel oil day tank retaining wall is within the scope of license renewal and is contained in Table 3.5-2 (page 3.5-10, row 2) of the Application.

As clarification, highlighted flow diagrams show mechanical system evaluation boundaries. Structural components are generally not represented on flow diagrams, but in cases where they are, as in this case, the structural components are not addressed by the highlighting conventions.

RAI 2.3.3.14-4
Catawba drawing CN-2609-3.1, "Flow Diagram of Diesel Generator Engine Fuel Oil System (FD)," indicates that piping from valve 2FD41 to valve 2FD43 (at L-3) is not within the scope of license renewal. These are Duke Class C (ASME Class 3) components. Please indicate if the piping from valve 2FD41 to valve 2FD43 is within the scope of license renewal and, if it is, confirm that this piping is addressed in the AMR table. If this piping is not within the scope of license renewal, please provide a justification for excluding it.

Response to RAI 2.3.3.14-4
Piping from valve 2FD41 to valve 2FD43 is within the scope of license renewal. Highlighting was inadvertently left off that segment of piping and the license renewal flag was located incorrectly. The piping and valves associated with this segment are contained in Table 3.3-19 (page 3.3-140, rows 1 and 5) of the Application.

2.3.3.15 Diesel Generator Lube Oil System

RAI 2.3.3.15-1

Do the McGuire diesel generator engines have a system to collect leaking lube oil? The UFSAR does not discuss one, and there does not appear to be one shown on the diesel generator engine lube oil system drawings (drawings MCFD-1609-02.00, MCFD-1609-02.01, MCFD-2609-02.00 and MCFD-2609-02.01). However, it seems logical that there may be some features incorporated into the diesel generator engine lube oil system to do this. Please indicate if diesel engines are designed to collect lube oil leakage and transport it away from the diesel. If so, please explain how the collection system is addressed in the application. If the applicant does not believe that this system is within the scope of license renewal, please provide the basis for this conclusion.

Response to RAI 2.3.3.15-1

The McGuire diesel engines do not have a system to collect leaking lube oil and transport it away from the diesel engine. Leaking lube oil drops to the floor and enters the floor drains to be routed to the sump.

RAI 2.3.3.15-2
Do the Catawba diesel generator engines have a system to collect leaking lube oil? Section 9.5.7.2.1 of the Catawba UFSAR states that "Oil leakage from the diesel is collected in a sump in the diesel room." However, a lube oil leakage collection system does not appear to be one shown on the diesel generator engine lube oil system drawings (drawings CN-1609-02.00, CN-1609-02.02, CN-2609-02.00 and CN-2609-02.02). The intended function of this oil collection feature is not specifically stated; however, in general, oil collection systems function to ensure that leaking oil will not lead to a fire that could damage safety-related equipment. This intended function clearly meets the criteria for 10CFR54.4(a)(2). If the applicant determined during the preparation of their license renewal application (LRA) that the lube oil leakage collection system is within the scope of license renewal, then please provide a clarification as to the extent to which the piping and components (e.g., diesel generator lube oil drip tank, diesel generator lube oil drip tank pump, etc.) are within the scope of license renewal, and the basis for the boundary. If the applicant determined that the lube oil leakage collection system is not within the scope of license renewal, then please provide the basis for this conclusion given the potential fire hazard that could be created if this system failed.

Response to RAI 2.3.3.15-2
The Catawba diesel engines do not have a system to collect leaking lube oil and transport it away from the diesel engine. Leaking lube oil drops to the floor and enters the floor drains to be routed to the sump. Any leaking lube oil would not contact any components hot enough for ignition that could threaten the functionality of the diesel engines.

RAI 2.3.3.15-3
McGuire drawings MCFD-1609-02.00, MCFD-1609-02.01, MCFD-2609-02.00 and MCFD-2609-02.01 are highlighted to indicate the portions of the diesel generator lube oil system (LD) that are within the scope of license renewal for McGuire, Units 1 and 2, respectively. During our review of these drawings, we identified an inconsistency between the two Unit 2 drawings regarding the boundaries of piping/valves that are included within the scope of license renewal. Specifically, on drawing MCFD-2609-02.00, the 1 inch system low point drain piping and associated valve 2LD0092 (located at G-12 on the drawing) and the 1 inch system drain piping and associated valve 2LD0060 (located at G-11 on the drawing) are not shown as being within scope. The same piping and valves (2LD0094 and 2LD0061) on drawing MCFD-2609-02.01 are shown as being within the scope of license renewal. It appears that in both cases, drawing MCFD-1609-02.01 may be correct. The drain and test vent piping and valves should be within scope to ensure the pressure boundary of the in scope LD system piping. Please verify that the drain connections cited above are within the scope of license renewal. If they are not within the scope of license renewal, please provide the basis for their exclusion.

Response to RAI 2.3.3.15-3
On MCFD-2609-02.00, the 1 inch, system low point drain piping and associated valve 2LD0092 (located at G-12 on the drawing) and the 1 inch, system drain piping and associated valve 2LD0060 (located at G-11 on the drawing) 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 and valves associated with this segment are contained in Table 3.3-20 (page 3.3-143, row 5; page 3.3-144, rows 2 and 3) of the Application.

RAI 2.3.3.15-4

As noted in the previous question, McGuire drawings MCFD-1609-02.00, MCFD-1609-02.01, MCFD-2609-02.00 and MCFD-2609-02.01 depict the portions of the diesel generator lube oil system that are within the scope of license renewal. These drawings indicate that the diesel generator lube oil heater pump is within the scope of license renewal. The passive portions of this component (i.e., pump housing) has a pressure boundary intended function, however, it does not appear to be included in Table 3.3-20 as a component subject to AMR. Please explain how this component is addressed in the application, or provide the basis for not subjecting it to an AMR.

Response to RAI 2.3.3.15-4

The diesel generator lube oil heater pump was inadvertently omitted from Table 3.3-20 of the Application. Table 3.3-20 is supplemented to add an entry for the diesel generator lube oil heater pump is as follows:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
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 *Inspection Program for Civil Engineering Structures and Components* is described in Section B.3.21 of the Application.

2.3.3.16 Diesel Generator Room Sump Pump System

RAI 2.3.3.16-1

McGuire drawings MCFD-1609-07.00 and MCFD-2609-07.00 depict the portions of the diesel generator room sump pump (WN) system that are within the scope of license renewal. Both drawings indicate that the diesel generator room sump is not within the scope of license renewal. According to Section 9.5.10 of the McGuire UFSAR, the WN system is a Class C system. Similarly, Section 9.5.9 of the Catawba UFSAR state that the WN system is a Class C system starting at the room sump. The staff's review of the WN system, however, raises the question as to whether the WN system could perform its safety function should the sump fail. Since the sump collects fluid leakage within the diesel generator room, the WN sump is needed for the WN system to perform its function of protecting the diesel generators from flooding. In addition, significant degradation of the sump walls could potentially create debris that may damage or clog the sump pumps. It appears from the staff's review that the sump meets the criteria of 10 CFR 54.4(a)(2) as a non-safety structure whose failure could prevent the WN system from remaining functional during a design basis event. As such, please provide the basis for not including the McGuire and Catawba diesel generator room sumps within the scope of license renewal.

Response to RAI 2.3.3.16-1

The diesel generator room sump is within the scope of license renewal and is listed in the Application Table 3.5-2 (page 3.5-11, row 3) under component type "Sumps." As clarification, highlighted flow diagrams show mechanical system evaluation boundaries. Structural components are generally not represented on flow diagrams, but in cases where they are, as in this case, the structural components are not addressed by the highlighting conventions.

2.3.3.17 Diesel Generator Starting Air System

RAI 2.3.3.17-1

McGuire drawings MCFD-1609-04.00 and MCFD-2609-04.00 are highlighted to indicate the portions of the diesel generator engine starting air (VG) system that are within the scope of license renewal for McGuire, Units 1 and 2, respectively. During our review of these drawings, we identified an inconsistency between the two units regarding the boundaries of piping/valves that are included within the scope of license renewal. Specifically, on drawing MCFD-2609-04.00, the 1-¼ inch drain piping and associated valve 2VG0040 coming off the bottom of the 2B2 diesel generator starting air tank located at coordinates B-7 on the drawing are not shown as being within scope. The equivalent piping and valves (2VG0039, 2VG0038, and 2VG0037) for starting air tanks 2B1, 2A2, and 2A1 on the same drawing are shown as being within the scope of license renewal. It appears that the 2B2 diesel generator starting air tank drain piping and valve should actually be within scope to ensure the pressure boundary of the in scope FW system piping. Please verify that this drain connections is within the scope of license renewal. If they are not within the scope of license renewal, please provide the basis for their exclusion.

Response to RAI 2.3.3.17-1

The 1-¼ inch drain piping and associated valve 2VG0040 coming off the bottom of the 2B2 diesel generator starting air tank is 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 and valves associated with this segment are contained in Table 3.3-23 (page 3.3-151, row 5; page 3.3-152, rows 1 and 2) of the Application.

RAI 2.3.3.17-2

Table 3-4 of the McGuire UFSAR states that the diesel generator starting air system "Filter - Moisture Traps" are safety class 3 components. However, these components are not listed in Table 3.3-23 as components subject to an AMR, and drawings MCFD-1609-04.00 and MCFD-2609-04.00 do not show these components as being within the scope of license renewal. Please provide the basis for their exclusion from the scope of license renewal.

Response to RAI 2.3.3.17-2

The filters and associated moisture traps immediately down stream of the diesel generator starting air compressor aftercoolers on drawings MCFD-1609-04.00 and MCFD-2609-04.00 are Duke Class G components and are not within the scope of license renewal. These filters are not the filters referred to in Table 3-4 of the McGuire UFSAR.

The "Filter-Moisture Traps" referred to in Table 3-4 of the McGuire UFSAR are moisture traps on small filters on the starting air distributors. These filters and associated traps are located on the diesel engine and are QA-1, Duke Class C. Drawings MCFD-1609-04.00 and MCFD-2609-04.00 do not show these components. The traps on these filters are valves and are included in the Table 3.3-23 (page 3.3-152, rows 1 and 2) of the Application entry of "Valve Bodies." The filter, which serves a pressure boundary function, was omitted from Table 3.3-23 of the Application and should be supplemented with the following entry:

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

RAI 2.3.3.17-3
The staff reviewed the list of components identified as being subject to an AMR in Table 3.3-24 of the application, and compared the list with the passive long lived components identified as being within the scope of license renewal on Catawba drawings CN-1609-4.0, CN-1609-4.1, CN-2609-4.0, and CN-2609-4.1. The staff identified three passive, long-lived components identified on the drawings as being within the scope of license renewal that were not identified as being subject to an AMR in Table 3.3-24. These components are the diesel generator engine starting air compressor body, the diesel generator engine starting air dryers, and the governor oil pressure boost cylinder filter. These components have pressure boundary intended functions. Please explain how these components are addressed in the application, or provide the basis for not subjecting them to an AMR.

Response to RAI 2.3.3.17-3
The diesel generator starting air compressors are within the scope of license renewal, but are not subject to an aging management review and are not listed in Table 3.3-24 of the Application. Air compressors, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight air compressor exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

Table 3.3-24 of the Application does include the diesel generator engine starting air dryers. Table 3.3-24 lists the individual components that comprise the air dryer package.

- For air dryer packages 1A1 and 2A1, the components are between valves VG-37 and VG-109.
- For packages 1A2 and 2A2, the components are between valves VG-38 and VG-110.
- For packages 1B1 and 2B1, the components are between valves VG-81 and VG-131.

- For packages 1B2 and 2B2, the components are between valves VG-82 and VG-131.

The dryer components of filters, moisture separators, pipe, silencers, and valves are listed in Table 3.3-24. Towers are large pipe and are included in the "Piping" entry.

Catawba drawings CN-2609-4.0 and CN-2609-4.1 depict governor oil pressure boost cylinder filters at coordinates B-7. Catawba drawings CN-1609-4.0 and CN-1609-4.1 do not contain governor oil pressure boost cylinder filters. A visual inspection confirmed that governor oil pressure boost cylinder filters are not present in the system on either unit. As a result, Catawba drawings CN-2609-4.0 and CN-2609-4.1 are incorrect. A corrective action report has been entered into the corrective action program to correct the flow diagrams.

2.3.3.19 Fire Protection System

Note: The following Background Information is provided prior to providing responses to RAIs 2.3.3.19-1 through 2.3.3.19-10 to facilitate the staff's understanding of the 10 CFR 50.48 fire protection programs at McGuire and Catawba.

BACKGROUND INFORMATION

The systems, structures, and components (SSCs) within the scope of license renewal for compliance with §50.48 are those SSCs that 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. The following discussion is provided to explain that the focus of SSCs relied on to comply with §50.48 directly relates to the ability to safely shut down the plant and minimize radioactive releases in the event of a fire. This discussion offers information relevant to 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 §50.48.

The key to understanding the SSCs within the scope of license renewal for fire protection begins with the Commission's regulations. The license renewal scoping requirement in 10 CFR 54.4(a)(3) states:

> **10 CFR 54.4**
> (a) Plant systems, structures, and components within the scope of this part are - ... (3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48)... .

Compliance with §50.48 is the key to determining the plant SSCs relied on to perform fire protection functions. Compliance with §50.48 begins with the regulation itself, which states (underline added for emphasis):

> **10 CFR 50.48**
> (a)(1) Each operating nuclear power plant must have a fire protection plan that satisfies Criterion 3 of appendix A of this part.... (2) The plan must also describe specific features necessary to implement the program described in paragraph (a)(1) of this section such as...(iii) the means to limit fire damage to structures, systems, or components <u>important to safety so that the capability to safely shut down the plant is ensured</u>.

Appendix A of 10 CFR 50 provides the General Design Criteria for Nuclear Power Plants. Criterion 3 states:

> **10 CFR 50 Appendix A, General Design Criterion (GDC) 3**
> Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions.... Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety.

As described in §50.48 and quoted above, "structures, systems, and components important to safety" is clarified as those structures, systems, and components relied on so that the capability to safely shut down the plant is ensured. Based on the above quotations, the regulations clearly focus on a fire protection plan or program with the ability to limit fire damage to SSCs important to safety so that the capability to safely shut down the plant is ensured.

Several NRC-issued guidance documents help interpret the requirements of §50.48. NUREG-0800, *Standard Review Plan of Safety Analysis Reports for Nuclear Power Plants,* provides guidance of fire protection program requirements to staff reviewers. Branch Technical Position CMEB 9.5-1 and its predecessor Appendix A to Branch Technical Position APCSB 9.5-1 provides guidance acceptable to the staff for implementing a fire protection program in accordance with §50.48 and GDC 3. During original licensing, Catawba was reviewed against the guidelines of Branch Technical Position CMEB 9.5-1 and NUREG-0800. Although McGuire is licensed to Appendix A of Branch Technical position APCSB 9.5-1 and not specifically to Branch Technical Position CMEB 9.5-1 or NUREG-0800, Branch Technical Position CMEB 9.5-1 and NUREG-0800 provide guidance for reviewing a plant's compliance with regulations, and in turn provides insights into interpretations of those regulations.

The purpose of the fire protection plan mentioned in the first sentence of §50.48(a) is provided in NUREG-0800, Section 9.5.1, Fire Protection Program, which states (underline added for emphasis):

> **NUREG-0800, Section 9.5.1, Fire Protection Program**
> **I. Areas of Review**
> The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that <u>a fire will not prevent the performance of necessary safe plant shutdown functions</u> and will not significantly increase the risk of radioactive releases to the environment in accordance with General Design Criteria 3 and 5.

The implementation of GDC 3, for the purposes of §50.48, is explained further in NUREG-0800, Section 9.5.1, as follows (underlines added for emphasis):

> **NUREG-0800, Section 9.5.1, Fire Protection Program**
> **II. Acceptance Criteria**
> The applicant's fire protection program is acceptable if it is in accordance with the following criteria:
> 1. 10 CFR Part 50 §50.48, and General Design Criterion 3, as related to fire prevention, the design and operation of fire detection and protection systems, and administrative controls provided <u>to protect safety-related structures, systems, and components of the reactor facility.</u>
>
> ...
> The following specific criteria provide information, recommendations, and guidance and in general describe <u>a basis acceptable to the staff</u> that may be used to meet the requirements of §50.48, GDC 3 and 5:
> a. <u>Branch Technical Position (BTP) CMEB 9.5-1</u> as it relates to the design provisions given to implement the fire protection program.

The staff provided even more detailed guidance relevant to the implementation of a fire protection program in accordance with §50.48 and GDC 3 in the Branch Technical Position itself. The Branch Technical Position begins with the following statement:

> **Branch Technical Position CMEB 9.5-1**
> **A. Introduction**
> This BTP addresses protection programs for safety-related systems and equipment and for other plant areas containing fire hazards that could adversely affect safety-related systems. It does not give guidance for protecting the life or safety of the site personnel or for protection against economic or property loss.

The staff's guidance documents clearly focus on a fire protection program with the ability to limit fire damage to 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 earlier quote from the Acceptance Criteria section of NUREG-0800 indicates that implementing the guidelines of BTP CMEB 9.5-1 (attached to Section 9.5.1 of the SRP) is acceptable to the staff in meeting the requirements of §50.48 and GDC 3. This acceptance would be reflected in the specific plant's safety evaluation report (SER) based on a review of the plant-specific responses to the BTP. As documented in the respective McGuire and Catawba SERs, the staff found the fire protection programs acceptable based on the plant-specific BTP responses.

BTP CMEB 9.5-1 provides guidelines that can accommodate a full range of possible plant designs and layouts. Not all of these guidelines are applicable to all plants. One example of this is BTP Section C.7.q. which relates to cooling towers. It is obvious that not all plants have cooling towers.

Just as the cooling tower guidelines are not applicable to all plants, the general plant-wide design features discussed throughout the BTP are applicable only within the context of §50.48 requirements. In other words, the BTP guidelines are applicable as they relate to protecting 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. Examples of this focus can be found throughout the BTP with statements such as, "*within hose reach of areas containing equipment required for safe plant shutdown*" (Section C.1.c.3), "*Fixed self-contained lighting...should be provided in areas that must be manned for safe shutdown*" (C.5.g.1), "*Detection systems should be provided for all areas that contain or present a fire exposure to safety-related equipment*" (C.6.a.1), "*Outside manual hose installations should be...where fixed or transient combustibles could jeopardize safety-related equipment*" (C.6.b.7), and "*Miscellaneous areas...should be so located and protected that a fire...will not adversely affect any safety-related systems or equipment*" (C.7.r.).

McGuire and Catawba nuclear power plants are large facilities on large sites with many areas and structures located such that a fire in those areas or structures would not affect safety-related SSCs or the plant's ability to safely shut down. The SSCs that protect these areas or structures from fire are beyond the requirements of §50.48. The plants obviously have fire protection features that are related to protecting the life or safety of the site personnel or for protection against economic or property loss. These features are not intended to be the focus of the guidance in the BTP, as stated in the BTP introduction and quoted above. McGuire and Catawba responded to all BTP items even though (as shown in the previous paragraphs) not all items applied to each plant. Likewise, some BTP responses were answered in relation to the overall site fire protection program when the areas of NRC concern (according to NUREG-0800) relate only to protecting safety-related SSCs so that a fire will not prevent the performance of necessary safe shutdown functions and will not significantly increase the risk of radioactive releases.

The basis of the SSCs within the scope of license renewal for compliance with §50.48 was built upon the plant-specific responses to the BTP with the focus of identifying a specific subset of the overall site fire protection program. This subset of the overall site fire protection program is those SSCs that 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. Where technical justification can be made that a fire protection SSC merely mentioned in the plant-specific BTP response is not necessary to ensure that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases, that SSC is not required for compliance with §50.48. The plant-specific BTP responses, with this focus, have been used as the basis of the responses to RAIs 2.3.3.19-1 through 2.3.3.19-10 that follow.

RAI 2.3.3.19-1

As stated in the teleconference summary dated November 2, 2001, the staff asked the applicant to indicate if the Updated Fire Safety Analysis Report (UFSAR) was reviewed during the scoping evaluation. As stated in the teleconference summary dated October 2, 2001, the staff also asked the applicant to address if fire protection (FP) structures, systems, and components (SSCs) identified in the UFSAR as required for 10 CFR 50.48 are also identified in the applicant's Quality Assurance (QA) Condition 3 program.

As documented in the November 2, 2001 teleconference summary, the licensee indicated that the UFSAR was reviewed during the scoping evaluation, but that not all of the FP SSC's referred to in the UFSAR were part of the QA Condition 3 program (such as those in areas listed in Section 9.5.1.2.2 of the McGuire UFSAR and those in the turbine, service, and administration building areas listed in Section 9.5.1.2.1 of the Catawba UFSAR). These components were excluded from within scope of license renewal on the basis that they were not required for compliance to 10 CFR 50.48 and are not QA Condition 3.

This does not appear to be consistent with the applicant's QA program, Section 17, "Quality Assurance" which states that QA Condition 3 covers systems, components, items, and services which are important to FP as defined in the fire hazards analysis (FHA) for each station. It also goes on to say that the hazards analysis is in response to Appendix A to Branch Technical Position (BTP) 9.5-1. The staff's position is that exclusion of FP SSC's on the basis that its intended function is not required for protection of safety-related equipment is not acceptable if that SSC is required for compliance to 10 CFR 50.48. 10 CFR 50.48 provides for the protection of all SSC's important to safety to minimize the effects of a fire, as shown in Appendix A to BTP 9.5-1 and as written in General Design Criterion (GDC) 3. It appears that the applicant's QA Condition 3 designation applied to scoping is not inclusive of the entire 10 CFR 50.48 FP program.

Please provide technical justification for the exclusion of the UFSAR components from within the scope of license renewal from UFSAR Sections 9.5.1.2.2 and 9.5.1.2.1 for McGuire and Catawba, respectively. In addition, please submit the current FHA to the staff for McGuire and Catawba.

Response to RAI 2.3.3.19-1

Duke agrees with the staff that all SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with 10 CFR 50.48 are within the scope of license renewal. As referred to in the Background Information preceding this RAI response, the McGuire and Catawba nuclear power plants are large facilities on large sites with many areas and structures located such that a fire in those areas or structures would not affect safety-related SSCs or the plant's ability to safely shut down. The SSCs that protect these areas or structures from fire are beyond the requirements of §50.48.

Section 9.5.1 in the McGuire and Catawba UFSARs describe the overall site fire protection program and not just the portions required to meet the requirement of §50.48. As stated in the guidance for regulated event scoping in both NEI 95-10, Section 3.1.3, and NUREG-1800, Section 2.1.3.1.3, "*Mere mention of a system, structure, or component in the analysis or evaluation does not constitute support of a specified regulatory function.*"

The structures and areas identified in McGuire UFSAR Section 9.5.1.2.2 and Catawba UFSAR Section 9.5.1.2.1 are beyond the requirements of §50.48. These structures and areas are addressed in the BTP responses dealing with General Guidelines for Plant Protection where it is stated that the plant layout is arranged to isolate safety-related systems from unacceptable fire hazards. This isolation includes such things as Building Design ("*greater than 50 feet between oil-filled transformers and buildings containing safety-related equipment and fire barriers with a minimum fire rating of three hours separating fire areas*") and Control of Combustibles ("*safety-related systems are separated from combustible materials except when required for system operation*"). In cases like the Turbine Building and adjacent Auxiliary Building, the buildings are separated by a three hour fire barrier and it is the fire barrier that is credited as the means of isolation, not the automatic sprinkler systems or other fire protection and detection features in the Turbine Building.

Therefore, these other structures and areas that are mentioned in UFSAR Section 9.5.1 where a fire would not affect safety-related SSCs or the plant's ability to safely shut down are beyond the requirements of §50.48 and are not within the scope of license renewal.

The plant-specific BTP responses have been used as the basis of this response. If still required by the staff to make its finding, the McGuire and Catawba fire hazards analyses and BTP responses can be made available for on-site inspection.

2.3.3.19-2 through 2.3.3.19-10
The following questions involve components that were identified through the staff's review of license renewal boundaries depicted on flow diagrams. These components were not included in the license renewal boundaries and appear to have FP intended functions required for compliance with 10 CFR 50.48 as stated in 10 CFR 54.4. On this basis, the staff's view is that the components addressed in questions 2.3.3.19-2 through 2.3.3.19-10 should be included within the scope of license renewal.

RAI 2.3.3.19-2
The McGuire UFSAR, Section 9.5.1.2.3.2, "Reactor Building," specifically states that sprinkler systems are provided for reactor coolant pumps (RCP) 1A, 1B, 1C, 1D, 2A, 2B, 2C, 2D. Flow diagram MCFD-1599-02.02 excludes the FP piping leading to these pumps. As shown in the teleconference summary dated November 2, 2001, the licensee responded that the sprinkler system was installed in response to Oconee operating experience and that this system was never required for compliance to 10 CFR 50.48. In addition, the applicant further indicated that a RCP motor oil collection system had been installed as a backfit at McGuire and Catawba to isolate oil from potential ignition sources in accordance with Appendix R, Section O. This modification precluded the need for a sprinkler system in these areas. The staff verified that a RCP motor oil collection system had been installed and is satisfied with this information. However, the staff notes that the UFSAR needs to be updated to reflect the modification to the facility and associated obsolescence of the RCP sprinkler system. As such, the staff requests the applicant to indicate that a change to Section 9.5.1.2.3.2 of the UFSAR will be made to indicate that the sprinkler systems that had been provided for reactor coolant pumps (RCP) 1A, 1B, 1C, 1D, 2A, 2B, 2C, 2D are no longer needed to comply with 10 CFR 50.48 because of the modification to install the RCP motor oil collection system.

Response to RAI 2.3.3.19-2
A corrective action report has been entered into the corrective action program to identify and evaluate changes to clarify McGuire UFSAR Section 9.5.1.2.3.2 and update in the future as needed.

In addition, the comparable issue has been identified in Catawba UFSAR Section 9.5.1.2.1. A corrective action report has been entered into the corrective action program to identify and evaluation changes to clarify the Catawba UFSAR and update in the future as needed.

RAI 2.3.3.19-3
The McGuire 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. Section 9.5.1.1 of the McGuire UFSAR states that one of the objectives provided under the design bases for the FP system is to "provide automatic water spray (deluge) systems over oil hazard areas." Specifically, UFSAR Section 9.5.1.2.2, "Fire Protection, Non-Category I Safety Related," specifically states that water spray systems and sprinkler systems are provided for the protection of the oil storage house, the oxygen and acetylene gas storage yard area, compressed flammable gas cylinder storage area, main turbine piping and bearings, unit start-up and standby oil-filled power transformers, main turbine lube oil reservoirs, hydrogen seal oil unit, and the feedwater pump turbines. However, flow diagrams MCFD-1599-01.00 and MCFD-1599-03.00 indicate that the piping leading to these components is excluded from within scope of license renewal. This question and its basis also applies to the lube oil storage house and hazardous waste storage building represented in flow diagram CN-1599-1.0. Since the UFSAR is referenced in the license conditions, and these components are discussed therein, it appears that these components are required to meet the FP license condition as stated above. It addition, in the event of a fire, these components contain flammable liquids, which can be hazardous and can quickly escalate to generate high heat release rates and smoke. Provide justification for the exclusion of this piping from within the scope of license renewal.

Response to RAI 2.3.3.19-3
The license conditions mentioned in the RAI address the overall site fire protection program. As referred to in the Background Information preceding this RAI response, the McGuire and Catawba nuclear power plants are large facilities on large sites with many areas and structures where a fire would not affect safety-related SSCs or the plant's ability to safely shut down. The hazards identified in this RAI are separated from safety-related areas by distance and three-hour fire barriers, and therefore, the SSCs that protect these areas or structures from fire are beyond the requirements of §50.48. Section 9.5.1 in the McGuire and Catawba UFSARs describe the overall site fire protection program and not just the portions required to meet the requirement of §50.48. These existing license conditions will carry forward in the renewed license.

For details of why certain structures and areas are not within license renewal scope as discussed in this RAI, please refer to the Response to RAI 2.3.3.19-1.

RAI 2.3.3.19-4
The McGuire UFSAR Section 9.5.1.2.1 identifies that hydrants are connected to the yard main. Furthermore, fire hydrants are considered passive and long-lived components in accordance with 10 CFR 54.21. Flow diagrams MCFD-1599-01.00 and MCFD 1599-03.00 indicate that fire hydrants 07, 24, and 25 are not included within the license renewal boundary. These components appear to have FP intended functions required for compliance with 10 CFR 50.48 as stated in 10 CFR 54.4. The staff asked the applicant to provide the basis for the exclusion of some hydrants, which appear to have FP intended functions with 10 CFR 50.48.

In a teleconference summary dated November 2, 2001, the applicant responded that FP flowpaths that supply water to safety-related areas such as the auxiliary building and reactor building are within the scope of license renewal. These flowpaths are highlighted on the applicable flow diagrams. Some fire hydrants are located along the required fire protection flowpath and are not isolable from the flowpath. These hydrants are shown highlighted on the flow diagrams and are within the scope of license renewal because their pressure boundary loss may prevent water from being supplied to the required areas. Other fire hydrants exist in the fire protection system that are downstream of isolation valves that isolate the required fire protection flowpath from the rest of the system. The license renewal boundaries are located at these isolation valves, as shown on the applicable flow diagrams. Equipment in the portion of the system downstream of the isolation valves and the license renewal boundaries, including any fire hydrants, is not within the scope of license renewal. Furthermore, the applicant stated that no fire hydrants are relied upon to protect safety-related and/or safe shutdown equipment at McGuire.

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. Accordingly, 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. Please verify that the hydrants that are excluded from within the scope of license renewal are not located on the yard main system. If there are hydrants on the yard main system which are excluded from within scope of license renewal, address how aging of those hydrants will be managed to ensure that manual hose installation is sufficient to reach any location with an effective hose stream, in accordance with Appendix A to BTP 9.5-1 for McGuire and CMEB 9.5-1 for Catawba. In addition, submit any drawings which can clarify the location of hydrants with respect to plant structures.

Response to RAI 2.3.3.19-4
As stated in the Background Information preceding this RAI response, the general plant-wide design features discussed throughout the BTP are applicable (within the context of §50.48 requirements) only as they relate to protecting 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. Safety-related structures and areas at McGuire and Catawba are isolated from other plant structures and areas such that a fire in these other structures and areas will not prevent the performance of necessary safe plant shutdown functions.

This isolation includes such features as Building Design (greater than 50 feet between oil-filled transformers and buildings containing safety-related equipment and fire barriers with a minimum fire rating of three hours separating fire areas) and Control of Combustibles (safety-related systems are separated from combustible materials except when required for system operation). Safety-related structures are isolated from adjacent nonsafety-related structures and fire areas by a three hour fire barrier and it is the fire barrier that is credited as the means of isolation, not the manual fire suppression equipment in the yard.

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. As stated in the RAI, some hydrants are located along the required flow path and are not isolatable from the required flow path. These hydrants that cannot be isolated are within license renewal scope. The other hydrants are not in scope because they are not relied on for fire suppression of safety-related SSCs to ensure safe shutdown and are isolable from the required flow path (via being downstream of isolation valves). Upon failure of these downstream hydrants, or the associated downstream piping, the isolation valves can be used to isolate them from the portions of the system that protect safety-related SSCs to ensure safe shutdown. These isolable, downstream hydrants and piping are beyond the requirements of §50.48 and are not within the scope of license renewal. The license renewal evaluation boundary is at the isolation valves since they serve as the isolation point between the §50.48 and the non-§50.48 portions of the system.

RAI 2.3.3.19-5

Highlighted suction and discharge piping for the fire pumps on flow diagram MCFD-1599-01.00 indicates that the piping is within the scope of license renewal. However, the highlighting does not trace the outline of the fire pumps and associated strainers but passes through them. In a teleconference summary dated November 2, 2001, the applicant responded that the fire pump casings were within the scope of license renewal. However, the convention of highlighting the outline of these components on the flow diagram was not followed such that this was not clear on the flow diagrams. In addition, the strainers were not identified on the flow diagrams as being within the scope of license renewal. Please discuss if the strainers are included in scope and if they have been included in an aging management program. If they are not, please provide the basis for exclusion.

Response to RAI 2.3.3.19-5

The fire pumps and associated strainers are within the scope of license renewal. The red, triangular LR flags define the license renewal evaluation boundaries on mechanical system flow diagrams, and highlighting was used as an aid to Duke in component screening and for the reviewer in understanding the system under review. In some cases, components were outlined in highlighting, and in others, the highlighting was simply drawn through components. Either way is acceptable for achieving the purpose of the drawings. The components are shown to be within the license renewal evaluation boundaries, and therefore, within the scope of license renewal.

Although the flow diagram makes it appear that the strainer is a stand-alone component, the strainer is actually a subcomponent 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 subcomponents. As the strainer is a subcomponent of the pump and pumps (except casing) are excluded from aging management review per §54.21(i), the strainer is not subject to aging management review. The pump casings are subject to aging management review and are listed in Table 3.3.26 (page 3.3-172, row 1) of the Application for McGuire.

RAI 2.3.3.19-6
Flow diagrams MCFD-1599-01.00 and CN-1599-1.0 do not indicate that the jockey pumps are within the scope of license renewal. Operating License Conditions for McGuire and Catawba state, in part, that Duke Energy Corporation shall implement and maintain in effect all provisions of the approved FP program as described in the UFSAR and as approved in the SER through applicable supplements. Supplement 2 of the McGuire SER states that all fire water pumps are installed in accordance with the applicable National Fire Protection Association (NFPA) guidelines. NFPA 20-1980, "Standards for the Installation of Centrifugal Fire Pumps" states that a fire pump shall not be used as a pressure maintenance pump. Section 9.5.1.2.1 of the McGuire UFSAR states that jockey pumps are provided to prevent frequent starting of the fire pumps by maintaining pressure in the yard mains.

Supplement 2 of the Catawba SER states that performance capabilities of the fire pumps meet Section 6.b of the BTP CMEB 9.5-1 and are therefore acceptable. Section 6.b of BTP CMEB 9.5-1 states that the fire pump installation should conform to NFPA 20. NFPA 20-1980 states that a fire pump shall not be used as a pressure maintenance pump. Section 9.5.1.2.1 of the Catawba UFSAR states that jockey pumps are provided to prevent frequent starting of the fire pumps by maintaining pressure on the system.

In a teleconference summary dated November 2, 2001, the applicant indicated that the jockey pumps were not within the scope of license renewal because they are not QA Condition 3 components and because a failure of these components would not cause a loss of intended function. The staff does not have confidence that the QA Condition 3 designation includes all of the components required for compliance 10 CFR 50.48. This has resulted in the exclusion of 10 CFR 50.48 required components such as the jockey pump casings for McGuire and Catawba. Provide justification for (1) the exclusion of the jockey pumps; and (2) 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).

Response to RAI 2.3.3.19-6
This RAI requests justification for (1) the exclusion of the jockey pumps; and (2) 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 following are the responses to each of these two items.

(1) As stated in the Background Information preceding this RAI response, the general plant-wide design features discussed throughout the BTP are applicable (within the context of §50.48 requirements) only as they relate to protecting 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. Section 9.5.1 in the McGuire and Catawba UFSARs describe the overall site fire protection program and not just the portions required to meet the requirement of §50.48. As stated in Section 9.5.1 of the UFSARs, the function of the jockey pumps is to prevent frequent starting of the fire pumps by maintaining pressure in the yard mains. In this capacity, the jockey pumps and associated components act as a support system feature that refills the suppression system during standby mode when the system has lost water due to normal system "leakage." The jockey pumps and associated components do not provide a function that protects 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. Once there is more than normal system "leakage" (as would be caused by system use during a fire) the fire pumps are the components relied on for protecting 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 jockey pumps and associated components (a) provide only a support function and not an intended function, (b) are not relied on for fire suppression of safety-related SSCs, and (c) are isolatable from the required flow path via isolation valves. The jockey pumps and associated components support the establishment of the initial condition of the main fire suppression system <u>prior to</u> the initiation of a fire. Upon failure of the jockey pumps or associated components the isolation valves can be used to isolate them from the portions of the fire suppression system that protect safety-related SSCs. Failure of the jockey pumps and associated components does not result in a loss of the fire suppression system function. For all of the above reasons, Duke concludes that the jockey pumps and associated components are beyond the requirements of §50.48 and are not within the scope of license renewal.

(2) The McGuire and Catawba Quality Assurance (QA) Condition 3 program was built upon the plant-specific responses to the BTP with the focus of identifying the subset of the overall site fire protection program SSCs that 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. Based on the information presented in the Background Information preceding this RAI response, the QA 3 designation meets the requirements of §50.48. It was for this reason that QA 3 boundaries were used to designate those SSCs within the scope of license renewal for compliance with §50.48.

RAI 2.3.3.19-7
Piping to the Unit 1 and 2 containment mechanical equipment building fire hose racks (CN-1599-1.0 at K-10) & sprinklers (CN-1599-1.0 at L-11) that appear to have FP intended functions required for compliance to 10 CFR 50.48 are not highlighted on this flow diagram. In a conference call summary dated November 2, 2001, the applicant indicated that because the Unit 1 and 2 containment mechanical equipment buildings house non-safety-related ventilation equipment that cools the containment building to make it habitable for maintenance, operations, and radiation protection during refueling outages, they are not required by 10 CFR 50.48. The applicant also stated that these buildings are remotely located (one to two hundred feet) from the containment structure. This information is useful; however, it appears to be another case of FP components being excluded on the basis that they are not protecting safety-related equipment even though they appear to have fire protection intended functions in accordance with 10 CFR 50.48, which includes SSCs important to safety provided to minimize the probability and effect of fires and explosions.

Please indicate if the Unit 1 and 2 containment mechanical equipment building fire hose racks (at K-10) & sprinklers are provided to protect equipment important to safety or to protect against the propagation of fire to surrounding structures (e.g. the refueling water storage tanks). In addition, discuss and submit documentation that supports your position that the hose racks and sprinklers are not required for 10 CFR 50.48.

Response to RAI 2.3.3.19-7
As stated in the Background Information preceding this RAI response, safety-related structures are isolated from adjacent nonsafety-related structures and fire areas by a minimum distance or a three hour fire barrier. In this instance, separation is credited as the means of isolation between the containment mechanical equipment building and Containment, not the fire hose racks, sprinklers or other fire protection features. For a further explanation of the basis of this position please refer to the Response to RAI 2.3.3.19-1.

The fire hose racks and sprinklers in the Unit 1 and 2 containment mechanical equipment buildings are not provided to protect equipment important to safety. The containment mechanical equipment buildings house nonsafety-related ventilation equipment that cools the containment building to make it habitable for maintenance, operations, and radiation protection during refueling outages.

The only safety-related structure that the containment mechanical equipment buildings could create an exposure for is the refueling water storage tank. The refueling water storage tank is surrounded by a 2-foot-thick missile wall that is capable of containing sufficient quantity of refueling water in the event the tank becomes damaged. If a fire in the containment mechanical equipment building was to impact the refueling water storage tank, the 13-foot-high water-tight missile barrier would contain the borated water volume sufficient to mitigate the consequences of the most limiting event requiring the operation of the Emergency Core Cooling System. Since a fire in the containment mechanical equipment building could not impact the safety-related refueling water storage tank and prevent the safe shutdown of the plant, the fire protection features of the containment mechanical equipment building are not required for compliance with §50.48 and are not within the scope of license renewal.

Catawba UFSAR Section 3.5.2 provides additional information on the missile wall.

RAI 2.3.3.19-8
Section 9.5.1.2.1 of the UFSAR states that manual hose stations and automatic sprinkler or deluge systems are provided for the protection of turbine building components. Piping to the Unit 1 and 2 Turbine building (CN-1599-1.0 at J-8, K-6, C-6, and C-7) are not highlighted on the flow diagram. These components appear to have FP intended functions in accordance with 10 CFR 50.48. On this basis, the staff's view is that this piping should be included within scope of license renewal. In a teleconference summary dated November 2, 2001, the applicant indicated that no safety-related or safe shutdown equipment is housed in the turbine buildings and the fire barriers are available to limit the spread of fire in the turbine building to other buildings that contain safety-related or safe shutdown equipment. This information is helpful to the staff but it does not address the principal concern, that the hose stations and sprinkler deluge systems were installed for compliance to 10 CFR 50.48 as part of the applicant's Appendix A to CMEB 9.5-1 FP program for protection of SSC's important to safety. Provide justification for the exclusion of this piping from within scope of license renewal. In addition, verify that the FHA does not rely upon the use of manual hose stations and automatic sprinkler or deluge systems for the Unit 1 and 2 Turbine Building.

Response to RAI 2.3.3.19-8
As stated in the Background Information preceding this RAI response, the general plant-wide design features discussed throughout the BTP are applicable (within the context of §50.48 requirements) only as they relate to protecting 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. Safety-related structures and areas at McGuire and Catawba are isolated from other plant structures and areas such that a fire in these other structures and areas will not prevent the performance of necessary safe plant shutdown functions.

The Turbine Building is a nonsafety-related structure. The Turbine Building and adjacent Auxiliary Building are separated by a three hour fire barrier and it is the fire barrier that is credited in the BTP response and the FHA as demonstrating compliance with 10 CFR 50.48, not the automatic sprinkler systems, manual hose stations or other fire protection and detection features installed in the Turbine Building.

RAI 2.3.3.19-9

Section 9.5.1.2.1 of the UFSAR states that the RF system provides a fixed water suppression system for charcoal filters. Fire protection piping to charcoal filters is not highlighted on flow diagrams CN-1599-2.1 and CN-1599-2.2. In a teleconference summary dated November 2, 2001, 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. As stated before, the exclusion of FP SSC's from within scope of license renewal, on the basis that it is not protecting safety-related SSC's in not acceptable since the scope of 10 CFR 50.48 is not limited solely to the protection of safety-related SSC's. Provide justification for the exclusion of this piping.

Response to RAI 2.3.3.19-9

The fire protection design features for the subject filters are mentioned in response to the BTP. This portion of the fixed water suppression is not related to protecting 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. As stated in the Background Information preceding this RAI response, the general plant-wide design features discussed throughout the BTP are applicable (within the context of §50.48 requirements) only as they relate to protecting 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. Additionally, as stated in NEI 95-10, Section 3.1.3, SSCs Relied on to Demonstrate Compliance With Certain Specific Commission Regulations, (and NUREG-1800, Section 2.1.3.1.3) *"Mere mention of a system, structure, or component in the analysis or evaluation does not constitute support of a specified regulatory function."*

The subject filters are not charcoal filters, but are high-purity carbon filters. 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 carbon filters are not combustible in the environment for which they are designed to operate. The fixed water suppression system provided for these carbon filters are similar to those provided for the reactor coolant pumps discussed in RAI 2.3.3.19-2. The need for a fixed water suppression system has been precluded by the use of the bed filter with an essentially noncombustible material. The fixed water suppression system for these filters is beyond the requirements of §50.48 and, therefore, not within the scope of license renewal.

Catawba flow diagrams and other in-house documents refer to these filters as charcoal filters. A corrective action report has been entered into the corrective action program to identify and evaluate changes to the in-house design documents to properly identify the filter beds as carbon filters and to update them in the future as needed.

RAI 2.3.3.19-10

Flow diagrams CN-1599-2.1 and CN-1599-2.2 indicate that fire protection system piping from the nuclear service water system to the nuclear service water structure that appears to have FP intended functions required for compliance with 10 CFR 50.48 is not highlighted in these flow diagrams. In a teleconference summary dated November 2, 2001, the applicant responded that a modification had been implemented to install fire hydrants 61 and 62 in the yard outside the nuclear service water pump structure. This modification precluded the need to rely on the nuclear service water system for FP of the pump structure. These fire hydrants were governed by the operability requirements specified in Selected Licensee Commitment 16.9-23, which states that fire hydrants 61 and 62 are required to be operable whenever equipment in the nuclear service water system pump structure is required to be operable. The applicant further indicated that a future modification to remove the nuclear service water system piping and components associated with FP of the pump structure is planned. The staff reviewed flow diagram CN-1599-1.2 to verify that hydrants 61 and 62 were within the scope of license renewal. The staff also reviewed Selected Licensee Commitment 16.9-23 to verify the function of these hydrants. Since the drawings imply that the piping from the nuclear service water system to the nuclear service water structure performs FP intended functions required for compliance with 10 CFR 50.48, and the UFSAR does not address this piping or fire hydrants 61 and 62 in sufficient detail to support the staff's review of this issue, please verify that the staff's interpretation of this information is correct. Specifically, please discuss the modification to install fire hydrants 61 and 62; provide the staff with the modification number and the date that the modification was implemented (modification completion date will suffice); and indicate any plans to implement future modifications to remove the nuclear service water system piping and components associated with FP of the pump structure.

Response to RAI 2.3.3.19-10

The staff's interpretation is correct in that a modification was performed to install hydrants 61 and 62, which precluded the need to rely on the nuclear service water system for fire protection of the nuclear service water pump structure. These hydrants are within the evaluation boundaries of the highlighted flow diagrams and are within the scope of license renewal.

The modification to install hydrants 61 and 62 was implemented in 1997. Based on discussion with the staff subsequent to the issuance of this RAI, a modification number is not required. In the period since the flow diagrams were highlighted to show the license renewal evaluation boundaries, the piping from the nuclear service water system to the nuclear service water pump structure hose stations has been cut and capped. The flow diagram that shows fire protection system piping from the nuclear service water system to the nuclear service water structure hose stations is actually shown on CN-1599-2.3, not the drawings listed in the RAI. The current revision of flow diagram CN-1599-2.3 shows the piping was capped in 2001. The current revision to this flow diagram was reviewed by the staff during the scoping methodology inspection in March 2002. The modification to remove the hose racks and reconfigure the nuclear service water piping has been designed and scheduled for implementation.

2.3.3.24 Liquid Waste System and Waste Gas System

RAI 2.3.3.24-1

The scoping methodology in Section 2.1.2.1.3 of the LRA indicates that at a system level, the "intended functions" are used by the applicant as the bases for including this system within the scope of license renewal as specified in 10 CFR 54.4(a)(1)-(3). In Section 2.3.3.24, Liquid Waste System of the LRA for McGuire and Catawba, these intended system functions are not identified. Please identify those intended system functions that were used for scoping portions of the liquid waste system to be within the scope of license renewal.

Response to RAI 2.3.3.24-1

The scoping methodology used to identify the systems within the scope of license renewal is described in Section 2.1.1 of the Application, not Section 2.1.2.1.3 as the RAI states. Section 2.1.2.1.3 describes the process to identify the intended function(s) of each component subject to aging management review, not the scoping methodology.

By using the process described in Section 2.1.1 of the Application, Duke determined that the McGuire Liquid Waste Systems described in Section 2.3.3.24 of the Application is in the scope of license renewal because (1) portions of the systems are safety-related, (2) portions of the systems are designated as Class F piping, (3) portions of the systems are required to remain functional for fire protection and station blackout, and (4) portions of the systems are environmentally qualified. System intended functions were not used to determine if the Liquid Waste Systems are within the scope of license renewal.

Using the same scoping process, Duke determined that the Catawba Liquid Waste System described in Section 2.3.3.24 of the Application is in the scope of license renewal because (1) portions of the system are safety-related, (2) portions of the system are designated as Class F piping, (3) portions of the system are required to remain functional for fire protection and station blackout, and (4) portions of the system are environmentally qualified. System intended functions were not used to determine if the Liquid Waste System is within the scope of license renewal.

2.3.3.26 Nitrogen System

RAI 2.3.3.26-1

Catawba Flow Diagram CN-1602-1.0, "Nitrogen System," depicts nitrogen supply lines not in-scope supplying the containment valve injection water system (NW). The NW system prevents leakage of containment atmosphere past certain containment isolation valves (CIV's) following a loss of coolant accident (LOCA) by injecting seal water at a pressure exceeding containment accident pressure between the two seating surfaces of the CIV's. The water that gets injected comes from one of two surge chambers that are pressurized with nitrogen. The nitrogen pressure provides the driving force to flow the water between the valves. Section 6.2.4.2.2 of the UFSAR states that the NW system is designed to meet all Regulatory and Testing requirements set forth in Paragraph III-C of 10 CFR 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 finds that this function of the nitrogen system falls under the scoping requirements of 10 CFR 54.4(a)(2) for nonsafety-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 10 CFR 54.4(a)(1)(iii), "the capability to mitigate the consequences of accidents...," appears to apply. The staff finds 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. Please provide the basis for not including these components in scope.

Response to RAI 2.3.3.26-1

The nitrogen overpressure on the Containment Valve Injection Water (NW) System is used only under normal operating conditions and not relied upon during a design basis event. 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 containment isolation valves. The Nuclear Service Water System essential header piping is highlighted to indicate that it is within the scope of license renewal.

RAI 2.3.3.26-2

A power operated relief valve (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." These cylinders and the piping between them and the main steam line PORVs are apparently not depicted on any nitrogen system drawing. Please explain whether this run of piping and the cylinders are in scope. If not, please provide the basis for not including them in scope.

Response to RAI 2.3.3.26-2

The Catawba power operated relief valves are supplied with a backup nitrogen control system if normal instrument air is lost. The McGuire power operated relief valves do not have a backup nitrogen control system. The nitrogen control system for the Catawba power operated relief valves is not shown on any flow diagram. The nitrogen control system is comprised of tubing, valves, and nitrogen bottles. The nitrogen bottles are periodically replaced, and therefore, are not subject to an aging management review in accordance with 54.21(a)(1)(i). Table 3.3-34, Aging Management Review Results – Nitrogen System, of the Application is supplemented with the following entries:

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effects	Aging Management Programs and Activities
Valve Bodies (CNS PORV Control System)	PB	SS	Gas	None Identified	None Required
			Sheltered	None Identified	None Required
Tubing (CNS PORV Control System)	PB	SS	Gas	None Identified	None Required
			Sheltered	None Identified	None Required

RAI 2.3.3.26-3
On Catawba Flow Diagram 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. What is the function of this system? It is shown supplying actuators 1CF42, 1CF51, 1CF33, and 1CF60. At this point the diagram indicates NOTE 8. NOTE 8 appears to be missing from the diagram. Please provide NOTE 8.

Response to RAI 2.3.3.26-3
The independent nitrogen system depicted on license renewal drawing CN-1602-1.0 has no function and, in fact, has been abandoned. Since the time the drawings were highlighted for license renewal, the controlled flow diagram has been revised. Revision 23 of CN-1602-1.0 now shows the independent nitrogen system as cut and capped, nitrogen bottles removed, and abandoned in place with additional information in a note, Note 10, which states that this portion has been abandoned in place by plant modification and the portable nitrogen cylinders have been removed.

2.3.3.28 Nuclear Service Water System (Catawba Nuclear Station)

RAI 2.3.3.28-1

License Renewal Application paragraph 2.1.1.2.1 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 flow diagram 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 which may indicate it could be Class G piping that may be relied upon to remain functional during and following design basis events. It is not discernable from the flow diagram whether or not this piping is in scope. Is this Duke Class G piping within the scope of license renewal? If not, please provide the basis for not including in scope.

Response to RAI 2.3.3.28-1

The class G piping in the Nuclear Service Water System is not within the scope of license renewal. This piping is the normal 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. Note 16 on CN-1574-1.5 is simply making the statement that because the piping is underground, it is inherently missile protected and seismically designed. The note is not meant to imply that the piping is required to have such design features.

RAI 2.3.3.28-2

Catawba drawings CN-1574-1.0 and CN-1574-1.2, "Flow Diagram of Nuclear Service Water System (RN)," indicate that the nuclear service water motor coolers are within the scope of license renewal. Identify where in the LRA the AMR is for the nuclear service water motor coolers, or provide a justification for excluding these components from Table 3.3-37 and an AMR.

Response to RAI 2.3.3.28-2

The Nuclear Service Water System pump motor coolers are integral components of the Nuclear Service Water System pump motors, which are in the scope of license renewal, but not subject to aging management review in accordance with §54.21(a)(1)(i) of the Rule and, therefore, not listed in Table 3.3-37.

RAI 2.3.3.28-3
Catawba drawings CN-1574-1.0 and CN-1574-1.2, "Flow Diagram of Nuclear Service Water System (RN)," indicate the nuclear service water upper and lower oil reservoirs and RN pump motor upper bearing oil coolers are within the scope of license renewal. Identify where in the LRA the AMR is for the nuclear service water upper and lower oil reservoirs, and RN pump motor upper bearing oil coolers, or provide a justification for excluding these components from Table 3.3-37 and an AMR.

Response to RAI 2.3.3.28-3
The Nuclear Service Water System pump upper and lower oil reservoirs and bearing oil coolers are integral components of the Nuclear Service Water System pump motors, which are in the scope of license renewal, but not subject to aging management review in accordance with §54.21(a)(1)(i) of the Rule and, therefore, not listed in Table 3.3-37.

2.3.3.31 Reactor Coolant Pump Motor Oil Collection Sub-system

RAI 2.3.3.31-1

Flow Diagram CN-1553-1.3, "RCS," and MCFD-1553-04.00, "RCS," indicate that a portion of the drawing, with dashed lines surrounding the RCP motor and oil fill tank, is excluded from the scope of license renewal. Verify that this portion is not required for compliance with Appendix R, Section III.O.

Response to RAI 2.3.3.31-1

The portion of the Reactor Coolant Pump Motor Oil Collection Sub-system within the dashed lines on CN-1553-1.3 and MCFD-1553-04.00 is not required for compliance with Appendix R, Section III.O. This portion of the system is a portable skid that is connected to the system when needed to refill the motor with oil.

2.3.3.35 Standby Shutdown Diesel

RAI 2.3.3.35-1

Table 3.3-34 lists the components subject to an AMR for Standby Shutdown Diesel. The table lists the engine radiator as being subject to AMR (and therefore, within the scope of license renewal) under the cooling water and jacket water heating sub-system. From McGuire drawing MC-1614-4, it can be seen that the standby shutdown diesel engine radiator is air-cooled by an engine driven fan which draws air from outside the diesel room and discharges it through the radiator to the outside environment. Scoping criterion 10 CFR 54.4(a)(3) states that all systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63) are within the scope of license renewal. Clearly, the standby shutdown diesel and its supporting sub-systems are within the scope of license renewal because they are credited by the applicant for meeting 10 CFR 50.63. Accordingly, it appears the air cooling system for the standby diesel generator radiator should also be within the scope of license renewal. Please provide the basis for excluding this sub-system from the scope of license renewal.

Is a similar design utilized for the Catawba standby shutdown diesel? Table 3.3-34 does not appear to include any components for the air cooling subsystem for the standby shutdown diesel. If an air cooling system for is utilized for the Catawba standby diesel generator radiator to provide cooling for the standby diesel engine, it should also be within the scope of license renewal. Please provide the basis for excluding this sub-system from the scope of license renewal. If the Catawba standby shutdown diesel does not have an air cooling subsystem for the radiator, then please explain how the standby shutdown diesel engine is cooled.

Response to RAI 2.3.3.35-1

The first part of the question relates to the air cooling system for the McGuire standby shutdown diesel generator radiator. This sub-system was not excluded from the scope of license renewal. As indicated on MC-1614-4 by its inclusion in the circle designating the license renewal boundaries, the air cooling system for the standby shutdown diesel generator radiator system is within the scope of license renewal. One point not made clear in the Application is that the aging management review results for the air cooling system for the McGuire standby shutdown diesel generator radiator is included with the Table 3.3-46 of the Application, Turbine Building Ventilation System, rather than with the Standby Shutdown Diesel System. The Turbine Building Ventilation System performs the HVAC function for the Standby Shutdown Facility. See Section 2.3.3.37 of the Application for a description of the Turbine Building Ventilation System.

The Catawba standby shutdown diesel is the same design as the McGuire diesel. The aging management review results for the air cooling system for the standby shutdown diesel generator radiator is included with the Table 3.3-33 of the Application, Miscellaneous Structures Ventilation System, rather than with the Standby Shutdown Diesel System. The Miscellaneous Structures Ventilation System performs the HVAC function for the Standby Shutdown Facility.

The only passive, long-lived component associated with the air cooling system for the standby shutdown diesel generator radiator is the plenum. Those components not subject to aging management review, such as the fans, are shown within scope on the drawing but are not listed in the aging management review results tables of Chapter 3. Cooling fans are not included in the aging management review results tables in the Application. Cooling fans, without sub-component exceptions, are explicitly excluded from an aging management review by §54.21(a)(1)(i) of the Rule. As an aid to the reviewer, the following excerpt of §54.21(a)(1)(i) is provided (underline added to highlight cooling fan exclusion from aging management review):

> **10 CFR 54.21(a)(1)(i):**
> That perform an intended function, as described in §54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

RAI 2.3.3.35-2

Table 3.3-34 provides the list of components subject to an AMR for the standby shutdown diesel. The table lists the pump casing for the "fuel oil transfer pump." However, McGuire drawing MCFD-1560-01.00 and Catawba drawing
CN-1560-1.0 do not show a pump by that name. Does the fuel oil transfer pump referred to in Table 3.3-34 actually refer to the standby shutdown fuel oil day tank pump shown on drawings MCFD-1560-01.00 and CN-1560-1.0? If not, please explain where the fuel oil day tank pump is addressed in the LRA.

Response to RAI 2.3.3.35-2

The "fuel oil transfer pump" listed in Table 3.3-34 refers to the component listed as "Standby Shutdown Fuel Oil Day Tank Pump" at coordinate F-2 on McGuire drawing MCFD-1560-01.00 and Catawba drawing CN-1560-1.0.

RAI 2.3.3.35-3

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 engine sub-systems that are within the scope of license renewal at McGuire and Catawba. These drawings indicate that there are flexible hose connections on the fuel oil sub-system on both sides of the engine that are within the scope of license renewal. The components are passive and should have a pressure boundary intended function, however, they do not appear to be included in Table 3.3-44 as components subject to AMR. Please explain how these components are addressed in the application, or provide the basis for not subjecting them to an AMR.

Response to RAI 2.3.3.35-3

The flexible hose connections located on either side of the standby shutdown diesel engine are replaced during the periodic maintenance on the diesel engine. Therefore, the flexible hose connections are not considered long-lived components, are not subject to an aging management review in accordance with §54.21(a)(1)(ii) of the Rule, and are not included in Table 3.3-44.

A point to be noted is that flow diagrams MCFD-1560-02.00 and CN-1560-2.0 show no fuel oil components.

RAI 2.3.3.35-4

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 engine sub-systems that are within the scope of license renewal at McGuire and Catawba. The McGuire and Catawba UFSARs do not provide any written description of these sub-systems. It is not apparent from the drawings how the lube oil sub-system accomplishes its intended function of lubricating the engine. As a result, the staff is unable to determine if all inscope, passive, long-lived components have been adequately captured for AMR. For instance, the drawings do not show a lube oil piping, pump, or valves nor are any listed for McGuire or Catawba in Table 3.3-44 (the table of components determined by the applicant to be subject to an AMR). Without an explanation of how the system performs its intended function, the staff cannot determine whether various potential lube oil sub-system components are not listed in Table 3.3-44 because of how the system is designed or because of an inadvertent oversight by the applicant. Accordingly, please provide a system description and explanation as to how this sub-system performs its intended function.

Response to RAI 2.3.3.35-4

The diesel engine in the Standby Shutdown Facility is a small 16-cylinder engine. The lube oil system is the same as those used in automotive engine applications. The entire lubrication system is contained inside the diesel engine. The only external component is the lube oil filters which are listed in Table 3.3-44 (page 3.3-254, rows 4 and 5) of the Application. The components internal to the engine (pump and lube oil cooler) are considered part of the diesel engine and are exempt from an aging management review in accordance with §54.21(a)(1)(i). As a result, only the components associated with the filter (mounting head and bypass) are listed in Table 3.3-44. The filter element itself is a consumable and not subject to an aging management review.

RAI 2.3.3.35-5
Table 3.3-44 lists the McGuire and Catawba components subject to an AMR for the cooling water and jacket water heating sub-system for the standby shutdown diesel. The table does not list piping or pump casings for this sub-system as being subject to an AMR. Please provide the basis for excluding these components from being subject to an AMR for this sub-system.

Response to RAI 2.3.3.35-5
Table 3.3-44 of the Application lists "Tubing" for Diesel General Cooling Water and Jacket Water Heating Sub-system. This entry includes the pipe in this subsystem. All of the pipe for this subsystem was provided by the vendor. Vendor manuals refer to this pipe as tubing which is reflected in Table 3.3-44. Visual inspections of the diesel confirmed that the tubing referred to in the diesel engine manuals is really carbon steel pipe. Therefore, the Table 3.3-44 entry for 'Tubing" is supplemented to read as follows:

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effects	Aging Management Programs and Activities
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

The *Chemistry Control Program* is described in Section B.3.6 of the Application, and the *Inspection Program for Civil Engineering Structures and Components* is described in Section B.3.21 of the Application.

The pump casing for the Diesel Generator Cooling Water and Jacket Water Heating Sub-system was inadvertently omitted from Table 3.3-44 of the Application. The Table 3.3-44 entry for pump casing should read as follows:

Component Type	**Component Function**	**Material**	**Internal Environment** / **External Environment**	**Aging Effects**	**Aging Management Programs and Activities**
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 *Chemistry Control Program* is described in Section B.3.6 of the Application, and the *Inspection Program for Civil Engineering Structures and Components* is described in Section B.3.21 of the Application.

2.3.3.38 Waste Gas System

RAI 2.3.3.38-1

In drawing CN-1567-1.0, the waste gas separator is highlighted to indicate that it is within the scope of license renewal. However, this component is not included in Table 3.3-47. Is this component within the scope of license renewal? And what are the results of Duke's aging management review?

Response to RAI 2.3.3.38-1

The waste gas separator is within the scope of license renewal and subject to aging management review. The results of the aging management review were discussed with the NRC staff on September 12, 2001 and documented by the NRC staff in a telecommunication summary dated October 10, 2001. The specific results are repeated here for the convenience of the reviewer.

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effects	Aging Management Programs and Activities
Waste Gas Separators	PB	SS	Gas	None Identified	None Required
			Sheltered	None Identified	None Required
Waste Gas Separators	PB	SS	Treated Water (unmonitored)	Cracking	Waste Gas System Inspection
				Loss of Material	Waste Gas System Inspection
			Sheltered	None Identified	None Required

The *Waste Gas System Inspection* is described in Section B.3.36 of the Application.

RAI 2.3.3.38-2
The scoping methodology in Section 2.1.2.1.3 of the LRA indicates that at a system level, the "intended functions" are used by the applicant as the bases for including this system within the scope of license renewal as specified in
10 CFR 54.4(a)(1)-(3). In Section 2.3.3.38, Waste Gas System, of the LRA for McGuire and Catawba, these intended system functions are not identified. Please identify those intended system functions that were used for scoping portions of the waste gas system to be within the scope of license renewal.

Response to RAI 2.3.3.38-2
The scoping methodology used to identify the systems within the scope of license renewal is described in Section 2.1.1 of the Application, not Section 2.1.2.1.3 as the RAI states. Section 2.1.2.1.3 describes the process to identify the intended function(s) of each component subject to aging management review, not the scoping methodology.

By using the process described in Section 2.1.1 of the Application, Duke determined that the McGuire Gas Waste System described in Section 2.3.3.38 of the Application is in the scope of license renewal because (1) portions of the system are safety-related, (2) portions of the system are designated as Class F piping, and (3) portions of the system are required to remain functional for fire protection. System intended functions were not used to determine if the Gas Waste System is within the scope of license renewal.

Using the same scoping process, Duke determined that the Catawba Gas Waste System described in Section 2.3.3.38 of the Application is in the scope of license renewal because (1) portions of the system are safety-related, (2) portions of the system are designated as Class F piping, and (3) portions of the system are required to remain functional for fire protection. System intended functions were not used to determine if the Gas Waste System is within the scope of license renewal.

Attachment 4
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Deferred Responses to NRC Requests for Additional Information
Duke Letters dated March 1, 8, and 15 2002

<u>2.1-2.a and 2.1-2.b - Scoping of Structures and Components that Meet 10 CFR 54.4(a)(2) Criteria</u>

An applicant has two options when performing its scoping evaluation for non-safety-related piping systems that have a spatial relationship with safety-related systems, structures or components (SSCs) such that their failure could adversely impact the performance of an intended safety function: a mitigative option or a preventive option.

<u>Mitigative option</u>: With the mitigative option, the applicant must demonstrate that plant mitigative features (e.g., pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, etc.) are provided to protect safety-related SSCs from a failure of non-safety-related piping segments. When evaluating the failure modes of non-safety-related piping segments and the associated consequences, age-related degradation must be considered. The staff notes that pipe failure evaluations typically do not consider age-related degradation when determining pipe failure locations. Rather, pipe failure locations are normally postulated based on high stress. Industry operating experience has shown that age-related pipe failures can, and do, occur at locations other than the high-stress locations postulated in most pipe failure analyses. Therefore, to utilize the mitigative option, an applicant should demonstrate that the mitigating devices are adequate to protect safety-related SSCs from failures of non-safety-related piping segments at any location where age-related degradation is plausible. If this level of protection can be demonstrated, then only the mitigative features need to be included within the scope of license renewal, and the piping segments need not be included within the scope.

<u>Preventive option</u>: if an applicant cannot demonstrate that the mitigative features are adequate to protect safety-related SSCs from the consequences of non-safety-related pipe failures, then the applicant should utilize the preventive option, which requires that the entire non-safety-related piping system be brought into the scope of license renewal and an AMR be performed on the system piping. An applicant may determine that, to ensure adequate protection of the safety-related SSC, a combination of mitigative features and non-safety-related piping segments must be brought within scope.

RAI 2.1-2.a

The staff requests that the applicant identify whether the mitigative option, the preventive option, or a combination, is used to identify non-safety-related **piping systems** that, if they failed, could adversely impact the performance of an intended safety function. For each non-safety-related piping system that would normally be included within the scope of license renewal, but is excluded because mitigative features have been credited for protecting safety-related SSCs from the failure of the non-safety-related piping system, please identify (1) the mitigative feature(s) that is credited for protection; (2) the hazard (e.g., failure mechanisms and postulated failure locations) for which the mitigative feature(s) is providing protection; and (3) a summary discussion (including references, such as reports, analyses, calculations, etc.) of the basis for the conclusion that the mitigative feature(s) is adequate to protect safety-related SSCs.

RAI 2.1-2.b
The staff requests that the applicant identify whether the mitigative option, the preventive option, or a combination, is used to identify non-safety-related non-safety-related systems, structures or components (**other than piping**) that, if they failed, could adversely impact the performance of an intended safety function. For these other non-safety-related systems, structures or components, an applicant can exercise the mitigative option, the preventive option, or a combination, to address the scoping issue. For each non-safety-related systems, structures or components identified as meeting the 54.4(a)(2) scoping criterion, list which option or combination of options is being credited. For those non-safety-related systems, structures or components that exercise the mitigative option, please identify (1) the mitigative feature(s) that is credited for protection; (2) the hazard (e.g., failure mechanisms and postulated failure locations) for which the mitigative feature(s) is providing protection; and (3) a summary discussion (including references, such as reports, analyzes, calculations, etc.) of the basis for the conclusion that the mitigative feature(s) is adequate to protect safety-related SSCs.

Response to RAIs 2.1-2.a and 2.1.2.b

McGuire and Catwaba Background for Responses to RAI 2.1-2.a and 2.1-2.b - Scoping of Structures and Components that Meet 10 CFR 54.4(a)(2) Criteria

Overview
The license renewal scoping methodology for nonsafety-related piping systems that have a spatial relationship to safety-related systems is built upon the criteria used during the design of the McGuire and Catawba plants. McGuire and Catawba are modern-vintage plants that are designed with rigorous analyses with respect to piping system interactions. The detailed consideration of both physical and fluid interaction from non-safety related sources on safety-related equipment was an integral part of the original design, continues to be maintained through the modification process, and provides the basis of license renewal scoping that meets 10 CFR 54.4(a)(2) criteria. The following sections provide additional detail on these design considerations and provide the foundation for the Duke Responses to RAI 2.1-2.a and RAI 2.1-2.b that follow.

Design Considerations
Two types of analyses have been performed for every area of the plant that houses safety-related equipment. These areas include the Reactor Buildings and Auxiliary Buildings at both McGuire and Catawba as well as the Nuclear Service Water Pump Structure at Catawba. One type of analysis considered the physical interaction (e.g. falling) of nonsafety-related structures and components on safety-related equipment. The other type of analysis considered fluid interaction

(e.g. leaking and spraying fluid) from nonsafety-related piping systems onto safety-related equipment and the impact on safety-related equipment due to flooding. Details on each of these analysis types are provided in the following sections. The design criteria described below were applied during original design and continue to be maintained through the modification process.

Physical Interaction

A physical interaction analysis was performed during the design of the plants to determine where falling of nonsafety-related structures and components could damage safety-related equipment. These analyses were known as seismic/nonseismic interaction analyses. The original plant seismic/nonseismic interaction design was done by iteration. As the mechanical systems were being designed, the physical placement of the components was conceptualized on the general arrangement and piping layout drawings. Specific design criteria ensured that locating nonseismic equipment near safety-related equipment was minimized. Reroute of piping and relocation of equipment were often the solution to a potential interaction concern. In some cases, piping reroutes and equipment relocation were not justifiable. For that reason, once the piping systems and components were installed, walkdowns of each area within the applicable structures were performed. Any nonseismic piping that was routed over safety-related equipment and was deemed to have a potential impact with the safety-related equipment in the event it fell, was provided with seismic supports to ensure that its failure would not impact the safety-related equipment. Likewise, if it was determined that overturning of nonseismic equipment could lead to potential impact with safety-related equipment, the nonseismic equipment was provided with seismic supports to ensure that its failure would not impact the safety-related equipment.

Providing nonseismic piping and equipment with seismic supports ensures that the physical interaction of nonsafety-related equipment falling on safety-related equipment will not prevent the satisfactory accomplishment of a safety function.

Fluid Interaction

A fluid interaction analysis was also performed during the design of the plants to determine where the impact of leaking, spray, and flooding from nonsafety-related sources on safety-related equipment must be considered. All piping systems at McGuire and Catawba fall into either the high-energy or moderate-energy piping system category.

High-energy piping systems are those systems, or portions of systems, that during normal plant conditions, operate at a temperature above 200°F or a pressure above 275 psig. Any piping system not meeting the definition of high-energy piping system is considered a moderate-energy system. Separate pipe rupture impact analyses, analyzing the impact of spray, are performed for high-energy piping systems and moderate-energy piping systems. These analyses were performed for inside containment and safety-related areas outside containment. A fluid interaction analysis for flooding was also performed for the safety-related areas of the plant.

The following discussion is divided into 5 categories: (1) high-energy pipe rupture inside containment, (2) high-energy pipe rupture outside containment, (3) moderate-energy pipe rupture inside containment, (4) moderate-energy pipe rupture outside containment, and (5) flooding analyses.

High-Energy Inside Containment

High-energy pipe ruptures inside containment are accounted for in the design by ensuring that all safety-related equipment inside containment is qualified to withstand the effects of the pipe rupture. Qualifying all safety-related equipment inside containment to withstand the effects of pipe rupture ensures that the fluid interaction of high energy nonsafety-related equipment on safety-related equipment inside containment will not prevent the satisfactory accomplishment of a safety function.

High-Energy Outside Containment

High-energy pipe ruptures in safety-related structures outside containment were evaluated for potential impacts. Pipe breaks identified at the high stress locations served to define the criteria used for pipe whip restraint and jet impingement shield design. Additional design conservatism was added to the nonsafety-related, high energy piping systems in safety-related structures outside containment by designating them Class F. A description of Class F piping systems is included in Section 2.1.1.2.1 of the Application. All high-energy piping systems in safety-related structures outside containment are either safety-related or Class F. The designation of piping as safety related or Class F ensures that the fluid interaction of high-energy nonsafety-related equipment on safety-related equipment outside containment will not prevent the satisfactory accomplishment of a safety function.

Moderate-Energy Inside Containment

Moderate-energy piping systems include all systems that are not high energy, both safety-related and nonsafety-related. Fluid interaction evaluations for leaking and spray were performed for all moderate-energy systems outside of containment at McGuire and Catawba. Fluid interaction evaluations were not performed inside containment because the design for the environmental consequences of a moderate energy leak or spray were enveloped by design features determined from the high-energy pipe rupture analyses performed inside containment as discussed above. Qualifying all safety-related equipment inside containment to withstand the effects of pipe rupture ensures that the fluid interaction of moderate-energy nonsafety-related equipment on safety-related equipment inside containment will not prevent the satisfactory accomplishment of a safety function.

Moderate-Energy Outside Containment
Moderate-energy spray evaluations were performed for moderate-energy system fluid interaction with safety-related electrical and electromechanical equipment located in safety-related structures outside containment. When performing a moderate-energy spray evaluation, a walk-down was conducted of all the equipment that was to be protected. For moderate-energy spray sources in the vicinity, a through wall crack was postulated at **all** pipe fitting welds and welded attachments of all moderate energy spray sources greater than one (1) inch nominal pipe size. The spray was assumed to impact equipment up to 30 feet in all directions from the spray source. Additional conservatism exists because of multiple pipe runs that exist in a given area. When multiple piping is routed in a specific area, the multiple welds that exist in each run of piping will be evaluated for impact. Welds in separate piping runs will likely be staggered, meaning that the pipe rupture evaluations cover the widest possible area.

Several options existed when a potential impact was identified. One option was to reroute the piping to eliminate the interaction. Another option was to relocate the safety-related equipment to eliminate the interaction. A third option was to qualify the safety-related equipment for the spray temperature and wetting effects for which it has the potential to be exposed. If none of those options were feasible, spray shields or drip shields would have been installed to protect the safety-related equipment from the potential pipe rupture hazard. Additionally, if the piping being evaluated for rupture was nonsafety-related, it could have been designated as Class F. A description of Class F piping systems is included in Section 2.1.1.2.1 of the Application. Employing the design options described above ensures that the fluid interaction of moderate energy nonsafety-related equipment on safety-related equipment will not prevent the satisfactory accomplishment of a safety function.

Flooding
Flood level evaluations were performed for flood zones within safety-related structures. The worst case flood level was determined by comparing the flood levels resulting from two events. The first event is the pipe rupture of a high or moderate-energy piping system. The pipe with the worst case mass release of fluid for a given flood zone was selected. The fluid release was calculated for 30 minutes, an assumed time for operators to isolate the break. The flood level was then calculated based on the volume of fluid released in the zone. The second event is the loss of all nonseismic piping and equipment. The location and volume of all nonseismic piping and equipment in a given flood zone was determined. That volume of fluid is assumed to contribute to the flood level. Added to that flood level was any outside fluid sources which may be released into the flood zone.

The design flood level in each flood zone is the highest flood level created by either a break in a high or moderate-energy pipe or the loss of all nonseismic piping and equipment. In the event that safety-related equipment within a flood zone was located at an elevation that was impacted by the flood level, several options existed. The piping contributing to the flood could be rerouted. The safety-related equipment could be moved to a higher elevation. Additional flood barriers could be added. Additionally, if the piping contributing to the flood was nonsafety related, it could be designated as Class F. A description of Class F piping systems is included in Section 2.1.1.2.1 of the Application. Employing the design options described above ensures that the physical interaction due to flooding of nonsafety-related equipment on safety-related equipment will not prevent the satisfactory accomplishment of a safety function.

Response to RAI 2.1-2.a
As can be noted from the McGuire and Catawba background discussion, the outcome of the detailed design consideration of physical and fluid interaction from non-safety related sources on safety-related equipment provides the basis for license renewal scoping that meets 10 CFR 54.4(a)(2) criteria. Using the terminology provided in the background for the RAI, Duke has identified items that meet both the mitigative option and the preventive option defined by the Staff. Mitigative features installed as a result of physical and fluid spatial interaction of both high energy and moderate energy piping breaks on safety-related equipment are included in the scope of license renewal. These items include pipe whip restraints, jet impingement spray shields, spray and drip shields, seismic supports, and flood curbs and barriers. These items are addressed in the Section 3.5 of the Application. For example, the equipment spray shields are included within the scope of license renewal as "Structural Steel Beams, Columns, Plates, and Trusses" in Table 3.5-2 of the Application. Similarly, the seismic supports are included within the scope of license renewal as "Pipe Supports" in Table 3.5-3 of the Application.

The preventive option is represented by the classification of various nonsafety-related piping systems as Class F. All Class F piping and components are included in the scope of license renewal. The following McGuire mechanical systems contain Class F piping and are within the scope of license renewal:
Auxiliary Building Ventilation
Auxiliary Feedwater
Auxiliary Steam
Boron Recycle
Chemical & Volume Control
Containment Air Return Exchange & Hydrogen Skimmer
Containment Purge Ventilation
Containment Ventilation Cooling Water
Control Area Chilled Water
Diesel Generator Fuel Oil
Diesel Generator Room Sump Pump
Equipment Decontamination
Feedwater

Ice Condenser Refrigeration
Interior Fire Protection
Heating Water
Hydrogen Bulk Storage
Instrument Air
Liquid Waste Monitor and Disposal
Liquid Waste Recycle
Main Steam
Main Steam Supply to Auxiliary Equipment
Main Steam Vent to Atmosphere
Nuclear Service Water
Reactor Coolant
Safety Injection
Steam Generator Blowdown Recycle
Turbine Exhaust
Waste Gas

The following Catawba mechanical systems contain Class F piping and are within the scope of license renewal:
Auxiliary Feedwater
Auxiliary Steam
Boron Recycle
Breathing Air
Building Heating Water
Chemical and Volume Control
Component Cooling
Condensate
Condensate Storage
Containment Air Release and Addition
Containment Air Return Exchange and Hydrogen Skimmer
Containment Hydrogen Sample and Purge
Containment Purge
Diesel Generator Engine Lube Oil
Diesel Generator Engine Starting Air
Drinking Water
Feedwater
Interior Fire Protection
Hydrogen Bulk Storage
Ice Condenser Refrigeration
Instrument Air

Liquid Radwaste
Main Steam
Main Steam Vent to Atmosphere
Makeup Demineralized Water
Nitrogen
Nuclear Service Water
Reactor Coolant
Recirculated Cooling Water
Solid Radwaste
Spent Fuel Cooling
Station Air
Steam Generator Blowdown
Steam Generator Wet Lay-Up Recirculation
Turbine Building Sump Pump
Waste Gas

Flow diagrams provided with the Application identify those portions of the above mechanical systems that are Class F.

Item (2) in RAI 2.1-2.a asks about the hazard (e.g. failure mechanisms and postulated failure locations) for which the mitigative features are providing protection. Any pipe failure due to age-related degradation is accounted for given that pipe rupture evaluations assumed a crack at every weld location. Because these welds can occur no more than every twenty (20) feet along the pipe (a standard length of pipe is no more than twenty (20) feet long) and each weld is assumed to impact equipment thirty (30) feet away, there can be no failure due to age-related degradation at any location along the piping that could impact equipment not already evaluated. Additional conservatism exists because of multiple pipe runs that exist in a given area. When multiple piping is routed in a specific area, the multiple welds that exist in each run of piping will be evaluated for impact. Welds in separate piping runs will likely be staggered, meaning that the pipe rupture evaluations cover the widest possible area.

The McGuire and Catawba background discussion above provides the summary requested in Item (3) in RAI 2.1-2.a and provides the basis for the conclusions that the mitigative features are adequate to protect safety-related SSCs. The results of the plant evaluations are documented in engineering documents and are available for inspection on site.

Response to RAI 2.1-2.b
Two categories of nonsafety-related systems, structures, and components (other than piping) could adversely impact the performance of an intended safety function if they failed. The first category includes components such as valves and pumps in wetted piping systems. The failure of these

components is accounted for in the discussion in response to RAI 2.1-2.a, because these components are welded into the system or are located near welds.

The second category includes non-wetted system components that, if they failed, could adversely impact the performance of an intended safety function. Using the terminology provided by the Staff in the background for the RAI, Duke has identified several items that meet the mitigative option for nonsafety-related structures and components other than piping system components whose failure could adversely impact the performance of an intended safety function. These non-wetted components include electrical cabinets, ladders and railings that could overturn or fall in a seismic event and impact safety related equipment. The seismic supports and restraints installed on these components serve as these mitigative features and are included in the scope of license renewal. These items are addressed in the Section 3.5 of the Application. These seismic supports and restraints are included within the scope of license renewal as "Electrical Instrument Panels and Enclosures" and "Stair, Platform, and Grating Supports" in Table 3.5-3 of the Application.

Item (2) in RAI 2.1-2.b asks about the hazard (e.g. failure mechanisms and postulated failure locations) for which the mitigative features are providing protection. The hazard that is being protected against is falling of non-wetted equipment.

The McGuire and Catawba background discussion above provides the summary asked for in Item (3) in RAI 2.1-2.a and provides the basis for the conclusions that the mitigative features are adequate to protect safety-related SSCs. The results of the plant evaluations are documented in engineering documents and are available for inspection on site.

Conclusion
No plant-specific or industry operating experience indicates that the design of McGuire and Catawba is non-conservative or would lead Duke to add any additional features to this design. The inclusion within the scope of license renewal of SSCs described above such as drip and spray shields, pipe supports, and Class F piping, provides reasonable assurance that failure of nonsafety-related systems, structures, and components due to age-related degradation will not prevent the satisfactory accomplishment of a safety function.

RAI 3.2-1
Since closure bolting is exposed to air, moisture, and leaking fluid (boric acid) environments, it is subject to the aging effects 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. Please indicate where in the LRA the AMR results for closure bolting are documented, or provide a justification for excluding closure bolting from an AMR, the results of which are documented in the referenced tables of the LRA.

Similarly, Table 3.5-3 provides no information to address the cracking initiation and growth from SCC for high strength low-alloy bolts. 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. State whether there is such a program and provide the reference.

Response to RAI 3.2-1
This response addresses closure bolting used in mechanical system applications and structural bolting used in various structural components. Closure bolting in mechanical system applications can be divided between Class 1 and non-Class 1 applications. Class 1 bolting which is larger in size and covered by specific ASME Section XI activities and is associated only with the Reactor Coolant System is addressed in the Application in Section 3.1. Non-Class 1 bolted closures are considered a subcomponent of the components listed in the Tables of Sections 3.2, 3.3 and 3.4 of the Application. 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. The Fluid *Leak Management Program* and the *Inspection Program for Civil Engineering Structures and Components* will manage this aging effect for the period of extended operation.

For high strength structural bolting, bolting is included as part of the structural component. Loss of material is the aging effect requiring management during the period of extended operation. Loss of material of structural components including the bolting is managed by the *Inservice Inspection Plan – Subsection IWF* or the *Inspection Program for Civil Engineering Structures and Components.*

Non-Class 1 mechanical closure bolting and high strength structural bolting are discussed in more detail below.

Non-Class 1 Mechanical Closure Bolting
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 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 of the same material and exposed to the same environment. Programs for the system (i.e., chemistry in a treated water system 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

No aging effects requiring management were identified for the stainless steel fastener set of bolted closures.

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 *Fluid Leak Management Program* is comparable to the Boric Acid Corrosion Program described in Section XI.M10 of the GALL Report.

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.

High Strength Structural Bolting

Structural bolting is included as part of the structural component such as pipe support, equipment support, structural steel, etc. and is addressed in Section 3.5 of the Application. According to industry literature, most degradation of structural connections results from galvanic or anodic corrosion. 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 Application. The inspection of the structural bolting for degradation would be included with the component.

Regarding the assertion in RAI 3.2-1 that stress corrosion cracking is a longer term aging issue for high strength low alloy structural bolting, no plant specific operating experience exists to support this position. Industry experience with stress corrosion cracking of structural bolting indicates a common feature of these failures is that high strength and/or overly hard 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. The majority 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.

RAI 3.3-1

Numerous ventilation systems included in Section 3.3 do not list elastomer components associated with the ventilation system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant designs, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are hardening and loss of material. Please indicate where in the LRA the aging effects of hardening and loss of material to elastomer components is addressed, or provide a justification for excluding these components from an AMR.

Response to RAI 3.3-1

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. Tables 3.3-1, 3.3-11, 3.3-13 and 3.3-28 are supplemented with the following aging management review results.

Table 3.3-1 Aging Management Review Results – Auxiliary Building Ventilation System (Supplemented)

Component Type	Component Function	Material	Internal Environment External Environment	Aging Effect	Aging Management Programs and Activities
Flexible Connectors (MNS Only)	Pressure Boundary	Neoprene*	Ventilation	None Identified	None Required
			Sheltered	None Identified	None Required
Flexible Connectors (CNS Only)	Pressure Boundary	Synthetic Rubber**	Ventilation	None Identified	None Required
		Ventsil***	Sheltered	None Identified	None Required

* Woven glass fabric double-coated with neoprene

** Flexible asbestos firewall fabric reinforced with Inconel wire and impregnated with a fluoroelastomer compound (synthetic rubber)

*** Ventsil™ is a trademark name for a glass fabric coated with silicone rubber.

Table 3.3-11 Aging Management Review Results – Control Area Ventilation System (Supplemented)

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
Flexible Connectors (CNS Only)	Pressure Boundary	Neoprene*	Ventilation	None Identified	None Required
			Sheltered	None Identified	None Required
Flexible Connectors (MNS Only)	Pressure Boundary	Neoprene*	Ventilation	None Identified	None Required
			Sheltered	None Identified	None Required

* Woven glass fabric double-coated with neoprene

Table 3.3-13 Aging Management Review Results – Diesel Building Ventilation System (Supplemented)

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
Flexible Connectors (MNS Only	Pressure Boundary	Neoprene*	Ventilation	None Identified	None Required
		Synthetic Rubber**	Sheltered	None Identified	None Required
Flexible Connectors (CNS Only)	Pressure Boundary	Neoprene*	Ventilation	None Identified	None Required
			Sheltered	None Identified	None Required

* Glass fabric coated with neoprene

** Flexible asbestos firewall fabric reinforced with Inconel wire and impregnated with a fluoroelastomer compound (synthetic rubber)

Table 3.3-28 Aging Management Review Results – Fuel Handling Building Ventilation System (Supplemented)

Component Type	Component Function	Material	Internal Environment / External Environment	Aging Effect	Aging Management Programs and Activities
Flexible Connectors (CNS Only	Pressure Boundary	Synthetic Rubber*	Ventilation	None Identified	None Required
		Ventsil**	Sheltered	None Identified	None Required
Flexible Connectors (MNS Only)	Pressure Boundary	Synthetic Rubber*	Ventilation	None Identified	None Required
			Sheltered	None Identified	None Required

* Flexible asbestos firewall fabric reinforced with Inconel wire and impregnated with a fluoroelastomer compound (synthetic rubber)

** Ventsil™ is a trademark name for a glass fabric coated with silicone rubber.

RAI 3.3-2
Clarify whether or not any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I systems, structures or components (SSCs) as described in position C.2 of Regulatory Guide 1.29. Also, clarify how the aging management programs provided in the AMR results tables of LRA Section 3.3 apply to those seismic II over I piping system to ensure that plausible aging effects associated with those piping systems, if any, will be appropriately managed. The applicant's discussion should include both piping segments and their associated pipe supports.

Response to RAI 3.3-2
Please see the response to RAIs 2.1-2.a and 2.1-2.b provided above for information on scoping seismic II over I systems, structures and components. The response to RAI 2.1-2.a provides a complete list of mechanical systems included within the scope of license renewal that fall into the category of seismic II over I systems. The aging management review results tables of Chapter 3 of the Application provides, for mechanical components of each system, the aging management program(s) that manages the applicable aging effects to ensure that the component intended function is maintained for the period of extended operation. If, for example, piping has a pressure boundary function, it does not matter whether the piping is in scope for safety-related or nonsafety-related reasons. Aging of the piping is managed to ensure that it maintains its pressure boundary function for the period of extended operation. The program that manages the pressure boundary function of the piping will manage that function regardless of its reason for inclusion in scope.

The aging management results of pipe supports that are within the scope of license renewal because they fall into the category of seismic II over I are included in Table 3.5-3 as "Pipe Supports". Function 7 of Table 3.5-3 is applicable for seismic II over I pipe supports and is managed for these supports by the aging management programs listed in the table for that entry.

RAI B.3.19-1
Periodic actions are taken to prevent cable from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit, and draining water. These actions are considered as preventive actions. Section B.3.19 of the LRA under topic heading "Preventive Actions" indicates no preventive actions are required as part of the Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program (AMP). Explain why no preventive actions are required as part of the AMP.

Response to RAI B.3.19-1
For reference, the Preventive Actions sections of GALL Report program XI.E3 and the McGuire and Catawba *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* are quoted below (underlines added for emphasis).

> **GALL Report Program XI.E3**
> **Preventive Actions:** <u>Periodic actions are taken</u> 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. ...
>
> **McGuire and Catawba Program**
> **Preventive Actions -** <u>No preventive actions are required</u> as part of the *Inaccessible Non-EQ Medium-Voltage Cables 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. ...

This 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, concrete trench or direct buried, most of the cable 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 this McGuire and Catawba program. This McGuire and Catawba program was not written for accessible medium-voltage cables.

During the review performed to respond to this 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 affects. These actions, such as inspecting cable manholes for water collection, would mainly affect the accessible portions of these cables but may provide symptomatic evidence of the conditions to which other portions of the cable are exposed.

For inaccessible portions of medium-voltage cables where such symptomatic cannot easily be obtained, GALL Report XI.E3 recognizes in its requirements that some cables might be exposed to significant moisture between the tests, which could be the entire period between tests, and finds that testing, alone, is adequate for aging management of these medium-voltage cables:

> **GALL Report Program XI.E3**
> **Detection of Aging Effects:** ...medium-voltage cables exposed to significant moisture...are tested at least once every 10 years. This is an adequate period to preclude failures....

Based on the review performed to respond to RAI B.3.19-1, the program descriptions contained in McGuire UFSAR Supplement 18.2.15 and Catawba UFSAR Supplement 18.2.14 will be revised by replacing existing text with the following text in the Scope, Preventive Actions and Monitoring & Trending program attributes.

McGuire and Catawba ***Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program*** **Description**

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 simultaneously with significant moisture.

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. 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 twenty-five percent of the time. Significant moisture is defined 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 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 conduit and draining water as needed.

Monitoring & 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).
(Second and third paragraphs under Monitoring & Trending remain unchanged.)

RAI B.3.19-2

Section B.3.19 of the LRA under topic heading "Scope" defines significant moisture as exposure to long-term (over a long period such as a few years), continuous standing water. Similar words are used in Section 3.6.2 of the LRA. The Oconee LRA defined significant moisture as exposure to moisture that lasts more than a few days. Explain why exposure to moisture over more than a few days, and up to a few years, is not significant.

Response to RAI B.3.19-2

Based on a review of industry literature on the topic of medium-voltage cables being exposed to moisture for long periods, no quantifiable data was found in the documents. However, the data and discussions in this industry literature (for example, EPRI TR-103834-P1-2, *Effects of Moisture on the Life of Power Plant Cables*, and SAND96-0344, *Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations*, which are referenced in GALL Report Program XI.E3) provides the reader with 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 GALL Report incorporated all previous operating experience into program XI.E3. 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 is reflected in statements in the GALL Report such as (underlines added for emphasis):

> **GALL Report Program XI.E3**
> **Preventive Actions:** ...operating experience indicates that <u>prolonged exposure</u> to moisture and voltage <u>are required to induce this aging mechanism</u>.

Prolonged exposure by any definition is more than a few days. The prolonged nature of the aging effects of concern in this program and the acceptability of an inspection period of "a few years" (as in the McGuire and Catawba program) is further recognized in the GALL Report with statements such as (underlines added or emphasis):

> **GALL Report Program XI.E3**
> **Detection of Aging Effects:** In-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested at least once every <u>10 years</u>. <u>This is an adequate period to preclude failures</u> of the conductor insulation since <u>experience has shown that aging degradation is a slow process</u>. ...

The GALL Report states in the quote above that cables exposed to significant moisture for up to 10 years are not expected to fail. This is in agreement with the statements that prolonged exposure is required in order for the aging mechanisms to be "induced" and that "experience has shown that aging degradation is a slow process". The McGuire and Catawba *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* defines significant moisture as "exposure to long-term (over a long period such as a few years), continuous standing water" because longer periods of exposure without action are accepted in GALL Report Program XI.E3.

Attachment 5
Application to Renew the Operating Licenses of
McGuire Nuclear Station and Catawba Nuclear Station
Responses to NRC Requests for Additional Information
NRC Letters dated January 23, 28(2), and 30, 2002

LIST OF COMMITMENTS

Attachment 5

Duke Letter Dated April 15, 2002
Response to NRC Requests for Additional Information
McGuire Nuclear Station and Catawba Nuclear Station

List of Commitments

1. The following statement will be added to Section 18.2.16 for and McGuire and Section 18.2.15 for Catawba in the respective UFSAR Supplement:

A VT-1 examination of the reactor vessel internals clevis insert fasteners will be performed in lieu of the VT-3 examination currently required by ASME Section XI.

(RAI 3.1.4-4)

2. The following are commitments:
   - As a result of the responses to this RAI, Duke will review changes to McGuire UFSAR Section 5.4.3 as contained in the McGuire UFSAR Supplement to determine the appropriate changes that should be made.

   - As a result of the responses to this RAI, Duke will review changes to Catawba UFSAR Section 5.3.3 as contained in the Catawba UFSAR Supplement to determine the appropriate changes that should be made.

   (RAI 4.2-1)

3. The McGuire and Catawba UFSAR Supplements will be revised to include the following summary description of the *Pressurizer Spray Head Examination:*

Pressurizer Spray Head Examination

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 thermal embrittlement.

Detection of Aging Effects – The *Pressurizer Spray Head Examination* is a one-time inspection will detect the presence of cracking due to thermal embrittlement for 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.

(RAI 2.3.2.7-1)

4. Based on the review performed to respond to RAI B.3.19-1, the program descriptions contained in McGuire UFSAR Supplement 18.2.15 and Catawba UFSAR Supplement 18.2.14 will be revised by replacing existing text with the following text in the Scope, Preventive Actions and Monitoring & Trending program attributes.

McGuire and Catawba *Inaccessible Non-EQ Medium-Voltage Cables Aging Management Program* Description

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 simultaneously with significant moisture.

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. 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 twenty-five percent of the time. Significant moisture is defined 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 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 conduit and draining water as needed.

Monitoring & 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).
(Second and third paragraphs under Monitoring & Trending remain unchanged.)