McGuire/Catawba
Application for Renewed Operating Licenses
NRC Requests for Additional Information (RAI)

The applicant for McGuire/Catawba NPPs described its aging management review (AMR) of the Auxiliary Systems in the following sections of its license renewal application (LRA): Section 3.3, "Aging Management of Auxiliary Systems." The staff reviewed applicable systems described in Tables 3.3-1 through 3.3-13 of the application to determine whether the licensee provided adequate information to meet the requirements of 10 CFR Part 54.4 for managing the aging effects of the Auxiliary Systems for license renewal.

Based on the staff review of the applicant's submittal, all information was found to be adequate to address aging management of these systems with the exception of the following RAIs:

Section 3.3, "Aging Management of Auxiliary Systems"

Auxiliary Systems (General)

- RAI-3.3.1

  Numerous locations in Section 3.3, "Aging Management of Auxiliary Systems," of the applicant's LRA identify stainless steel components with an internal environment of borated water. The external environment in most of these cases is identified as sheltered or reactor building with no aging effects identified and no aging management programs required. Identify where in the LRA is the AMR for the aging effects loss of material from boric acid corrosion due to potential leakage, or provide a justification for excluding this aging effect from Section 3.3 and an AMR.

- RAI-3.3.2

  Tables 3.3-1 through 3.3-13 do not address the aging effect of loss of material and crack initiation and growth for closure bolting in these systems. Identify where in the LRA is the AMR for closure bolting, which is exposed to air, moisture, and leaking fluid (boric acid) environments, or provide a justification for excluding the bolting from Tables 3.3-1 through 13 and an AMR.

- RAI-3.3.3

  The Chemistry Control Program, as defined in Appendix B, is used to manage aging effects for components, in part exposed to closed cooling water and treated water environments. LRA Sections 3.1, 3.2, 3.3, 3.4, 3.5, and 3.6 define treated water environments; however, the LRA fails to provide a definition for a closed cooling water environment. Provide a definition for a closed cooling water environment, or provide justification as to why the definition is not required.

- RAI-3.3.4

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 design, 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. Identify where in the LRA is the AMR for the aging effects of hardening and loss of material to elastomer component, or provide a justification for excluding them from tables for the numerous Section 3.3 ventilation systems and their associated AMR.

- RAI-3.3.5

Clarify whether any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I SSCs as described in position C.2 of Regulatory Guide 1.29. Also, clarify how the aging management programs provided in tables of the LRA Section 3.3 apply to those seismic II over I piping system to assure 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.

Auxiliary Building Ventilation System

- RAI-3.3-1.1

Section 2.3.3.1, "Auxiliary Building Ventilation," states that the auxiliary building ventilation system maintains the ECCS pump rooms at negative pressure during ESF actuation. It lists the safety injection pump room and the centrifugal charging pump room as areas included within the scope of license renewal. Identify where in the LRA is the AMR for safety injection or the centrifugal charging pump motor air-handling units, which are responsible for maintaining this negative pressure, or provide a justification for excluding these components from Table 3.3-1 and an AMR.

- RAI-3.3-1.2

Table 3.3-1 indicates that the Catawba shutdown panel area air conditioning unit condenser tubes are susceptible to fouling aging effects in a treated water environment. The chemistry control program, as described in Appendix B of the LRA, Section B.3.6, is identified as the aging management program. The stated purpose of chemistry control program in Appendix B is to manage loss of material and/or cracking of components. The program description does not include the aging effect of fouling. Explain how the chemistry control program manages the aging effects of fouling in the shutdown panel area air conditioning unit condenser tubes, or provide an AMP for managing this aging effect.

- RAI-3.3-1.3

In Table 3.3-1 Column 2 (Component Function), the abbreviation "HT" is used in conjunction with several component types; however, "HT" is not defined in the notes at the end of Table 3.3-1. Provide a definition for this abbreviation, or justify why no definition is required.

- RAI-3.3-1.4

  Table 3.3-1 Columns 1 and 5 (page 3.3-8 and 3.3-9) states that aging effects to the "shutdown panel area air conditioning unit condenser (shells & tube side bonnet) (CNS only)" is managed by the AMP, "Inspection Program for Civil Engineering Structures and Components." The scope of this program, as defined in Appendix B, Section B.3.21, does not include the condenser shells or tube side bonnets. Does the AMP, "Inspection Program for Civil Engineering Structures and Components," manage the aging effects to the shutdown panel area air conditioning unit condenser (shells & tube side bonnets) (CNS only)? If not, identify an appropriate AMP.

Boron Recycle System

- RAI-3.3-2.1

  Table 3.3-2 does not list the potential aging effect loss of material from boric acid corrosion to external surfaces of carbon steel and low alloy steel components exposed to boric acid leakage. Identify where in the LRA is the AMR for the aging effect of loss of material to external surfaces of carbon steel and low alloy steel components due to boric acid leakage, or provide a justification for excluding it from Table 3.3-2 and an AMR.

- RAI-3.3-2.2

  Table 3.3-2 identifies a carbon steel piping component in the boron recycle system for McGuire plant that has an air-gas internal environment with no aging effects or aging program required. The external environment is sheltered and has an aging effect of loss of material that is managed though the AMPs, Fluid Leak Management Program, and Inspection Program for Civil Engineering Structures and Components. The Fluid Leak Management Program, as described in Appendix B, Section B.3.1.5, monitors for boron leaks and possible loss of material in carbon steel systems. Since the stated internal environment of this component is air-gas (which does not leak), and not boric acid, explain this component's function in the system and how the aging effect is possible.

- RAI-3.3-2.3

  In Table 3.3-2 the only place that the flow accelerated corrosion program is credited as an aging management program is for carbon steel piping and valve bodies with an internal environment of treated water. UFSAR, Chapter 18.2.10, "Flow Accelerated Corrosion Program," however, identifies the only portion of the boron recycle system within the scope of license renewal that is susceptible to flow accelerated corrosion are the supply lines from auxiliary steam. Explain why the flow accelerated corrosion program is not identified for any steam systems associated with the boron recycle system. Also explain why it is identified as an aging management program for treated water systems.

- RAI-3.3-2.4

Table 3.3-2 has a "Note (3)," which implies that portions of the boron recycle system may be subject to alternate wetting and drying; however, this note is not used anywhere in the table. Clarify if Note (3) is applicable to Table 3.3-2. If so, explain how this environment and associated aging effects are managed in the LRA.

- RAI-3.3-2.5

  Table 3.3-2 states that orifices provide the function "PB." Typically, orifices also provide the function listed in Note 1 as "TH." Explain why orifices in the boron recycle system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-2.

- RAI-3.3-2.6

  Table 3.3-2 Note (1) contains a definition of a component function "HT"; however, there are no components in Table 3.3-2 listed as performing this function. Identify components in the boron recycle system that provide the function "HT," or remove the function from Note (1).

Chemical Volume Control System

- RAI-3.3-4.1

  Table 3.3-4 does not list the centrifugal charging pump bearing or speed reducer oil coolers as components. The charging pump bearing and speed reducer oil coolers, however, are identified in the AMP, "Pump Oil Cooler Heat Exchanger Preventive Maintenance Program," as components in the CVCS requiring review to manage the aging effects loss of material and fouling of copper nickel HX tubes. Identify where in the LRA is the AMR for the aging effects to centrifugal charging pump bearing or speed reducer oil coolers, or provide a justification for excluding these components from Table 3.3-4 and an AMR.

- RAI-3.3-4.2

  Section 3.3, "Auxiliary Systems," of the applicant's LRA discusses no TLAA associated with the chemical and volume control system which address concerns identified in NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant System." Identify where in the LRA is the AMR and TLAA for the aging effects associated with thermal stresses in piping connected to the reactor coolant system (i.e., high pressure injection letdown piping, which is identified as being within the scope of license renewal for the CVCS), or provide a justification for excluding these components from Table 3.3-4 and an AMR.

Component Cooling Water System

- RAI-3.3-6.1

  In Table 3.3-6 the component cooling (KC) heat exchanger tubes are identified as having a component function of pressure boundary (PB) and heat transfer (HT). All other heat exchanger tube components being cooled by CCW are identified as only having a pressure boundary function. Explain why HT is not considered as a component function for the following heat exchanger tubes: (NB evaporator package condenser, NB evaporator package distillate cooler, NB evaporator package vent condenser, NC pump motor upper and lower bearing oil coolers, liquid waste (WL) recycle reactor coolant drain tank coolers, NM sample system coolers, WG compressor package cooler. (Note: Table 3.3-7 for the Catawba CCW system lists the HT function for all heat exchangers.). Also, explain how the heat transfer function is verified for these heat exchangers since no aging management program is identified to monitor this function.

- RAI-3.3-6.2

In Table 3.3-6 the KC heat exchanger channel head has a carbon steel internal water environment exposed to raw water. Typically, the aging effect, fouling, is associated with raw water environments. Explain why fouling is not identified as an applicable aging affect to this component.

- RAI-3.3-7.1

Table 3.3-7 identifies several locations where components (the auxiliary feedwater pump motor coolers, KC heat exchanger tubes, NS, NI, NV pump motor cooler tubes) are subject to an aging effect of fouling in a treated water environment. The LRA states that this aging effect is managed by the chemistry control program. Appendix A-2, "USFAR Supplement," Section 18.2.4, "Chemistry Control Program," states that this AMP's purpose is to manage loss of material and/or cracking. Management of the aging effect, fouling, is not listed in Appendix B as a purpose for the Chemistry Control Program. Since the aging effect fouling is typically associated with raw water environments, explain how the chemistry control program manages fouling. Also, is the aging effect cracking also associated with this environment?

- RAI-3.3-7.2

Table 3.3-7 lists ventilation as an external environment for heat exchanger, CA pump motor cooler tubes and tube sheets. Normally in the CCW system, the tube side of the HX would contain the process fluid being cooled and the shell side has the treated component cooling water. Are these motor coolers actually room coolers for the locations where the pumps motors are located? Clarify that ventilation is the correct environment for the CA pump motor cooler tubes and tube sheet components. In addition, the aging effects associated with this same ventilation environment indicate that in one case there is no aging effect and the other the ventilation environment leads to loss of material. Explain the difference between the two ventilation environments that makes this possible. (NOTE: This same condition is stated for the KC pump motor, KF pump motor, NV pump motor, and ND pump motor cooler tubes.)

- RAI-3.3-7.3

Table 3.3-7 KC heat exchanger tube sheet has an internal environment of raw water, but fouling is not identified as an aging effect. The aging effect, fouling, is typically associated with raw water environments. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-7 and an AMR.

- RAI-3.3-7.4

  Table 3.3-7 NC pump upper and lower motor bearing coolers have a treated water internal environment with an oil external environment. No aging effect is identified for this environment. Oil systems subject to water contamination are typically subject to the aging effect loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to carbon steel for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-7 and an AMR. (Note: This issue is common to all oil coolers so far reviewed in the LRA.)

Condenser Circulating System

- RAI-3.3-8.1

  Per Table 3.3-8 the Catawba and Maguire carbon steel condenser circulating water system components are subject to an internal environment of raw water. Explain why the aging effect of fouling has not been identified in Table 3.3-8 for pipe, pump casings, strainers, and valve bodies in a raw water environment.

Containment Ventilation System

- RAI-2.2.3.7-1

  Section 2.2.3.7, "Containment Ventilation System," of the applicant's LRA states that, with exception of McGuire plant RTDs that are required for post-accident monitoring, the containment ventilation systems for McGuire/Catawba plants do not meet the license renewal scoping criteria. Industry experience has shown that degradation or other problems with the containment ventilation system may have detrimental effects on containment, vital equipment, and vital instrumentation within containment. Identify where in the LRA is the AMR for the aging effects to the containment ventilation system, or provide additional justification for excluding this system from an AMR.

Control Area Chilled Water System

- RAI-3.3-10.1

  Tables 3.3-9 and 3.3-10 credits the AMP, "Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program," for managing the aging effects of fouling and loss of material for copper-nickel alloy materials. The Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program, as defined in Appendix B of the applicant's LRA, manages for the loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials; but Appendix B's description does not include the material copper-nickel within the scope of the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program. Explain how the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water

Program manages for the loss of material or fouling for copper-nickel alloy materials, or provide an AMP for managing these aging effects to this material.

- RAI-3.3-10.2

  The Catawba control area chilled water system pumps (e.g., 1& 2CRA-CHWP-1) are indicated on flow diagrams CN-1578-2.0 and CN-1578-2.2, "Flow Diagram of Control Room Area Ventilation System," to be within the scope of license renewal. Identify where in the LRA is the AMR for control area chilled water pumps, or provide a justification for excluding these pumps from Table 3.3-10 and an AMR.

- RAI-3.3-10.3

  Per Tables 3.3-9 and 3.3-10, the Catawba and Maguire control room area chillers (oil cooler tubes, tube sheets and shells) are subject to an internal/external environment of treated water/oil. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to carbon steel for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-9 and 3.3-10 and an AMR.

- RAI-3.3-10.4

  CN-1578-2.1, "Flow Diagram of Control Area Chilled Water System," and CN-1578-1.3, "Flow Diagram of Control Room Area Ventilation System" indicate AHU 1SGR-AHU-3 is within the scope of license renewal. Identify where in the LRA is the AMR for AHU 1-SGR-AHU-3, or provide a justification for excluding this component from Tables 3.3-9 and 3.3-10 and an AMR.

- RAI-3.3-10.5

  Tables 3.3-9, 3.3-10, and 3.3-11 credit the AMP, Chemistry Control Program, for managing the aging effect of fouling. The Chemistry Control Program, as defined in Appendix B of the applicant's LRA, manages the aging effects of loss of material and cracking; but Appendix B's description does not include the aging effect of fouling within the scope of the Chemistry Control Program. Explain how the Chemistry Control Program manages the aging effect of fouling or provide an AMP for managing this aging effect (see RAI 3.3-1.2).

Control Area Ventilation System

- RAI-3.3-11.1

  The Catawba control area ventilation system filter trains (e.g., 1& 2CRA-PFT-1) are indicated on flow diagram CN-1578-1.0, "Flow Diagram of Control Room Area Ventilation System," to be within the scope of license renewal. Identify where in the LRA is the AMR for control area ventilation system filter trains, or provide a justification for excluding these filters from Table 3.3-11 and an AMR.

Diesel Building Ventilation Systems

- RAI-3.3-13.1

  Table 3.3-13 indicates that galvanized steel components are not subject to aging effects from exposure to ventilation or sheltered environments. Identify where in the LRA is the AMR for galvanized steel ductwork exposed to a sheltered environment, which is defined in Section 3.3.1, "Aging Management Review Results Tables," as having the potential to be moist, and have the potential for experiencing loss of material from general, pitting and crevice corrosion, or provide a justification for excluding these aging effects from Table 3.3-13 and an AMR.

- RAI-3.3-13.2

  Catawba and McGuire plant P&IDs, MC-1579-1.0, MC-2579-1.0, CN 1579-1.0, & CN 2579-1.0, for the diesel building ventilation system indicate that diesel building normal heating coils are subject to aging management review. Identify where in the LRA is the AMR for diesel building normal heating coils, or provide a justification for excluding these coils from Table 3.3-13 and an AMR.

MEMORANDUM TO: Christopher I. Grimes, Chief
License Renewal Standardization Branch
Division of Regulatory Improvement Programs

FROM: Louise Lund, Chief
Component Integrity and Chemical Engineering Section
Materials and Chemical Engineering Branch
Division of Engineering

Kamal A. Manoly, Chief
Civil and Engineering Mechanics Section
Mechanical and Civil Engineering Branch
Division of Engineering

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE MCGUIRE/CATAWBA NUCLEAR STATION APPLICATION FOR RENEWED OPERATING LICENSES (TAC NOS.: MB 2037, MB 2038, MB 2027, MB 2028)

By letter dated June 14, 2001, Duke Power submitted for EMCB view an application pursuant to 10 CFR Part 54, to renew the operating license for McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2. The NRC staff and its contractor, Pacific Northwest National Laboratory (PNNL) have reviewed the information contained in the license renewal application and have identified, in the attachment, areas where additional information is needed to complete its safety review of the auxiliary systems section of the license renewal application.

The staff reviewed applicable systems described in Tables 3.3-1 through 3.3-47 of the application to determine whether the licensee provided adequate information to meet the requirements of 10 CFR Part 54.4 for managing the aging effects of the auxiliary systems for license renewal.

Attachment: As stated

Docket Nos: 50-369, 50-337, 50-413, 50-414

CONTACT: Bart Fu, EMCB/DE
415-2467

MEMORANDUM TO:	Christopher I. Grimes, Chief License Renewal Standardization Branch Division of Regulatory Improvement Programs
FROM:	Louise Lund, Chief Component Integrity and Chemical Engineering Section Materials and Chemical Engineering Branch Division of Engineering Kamal A. Manoly, Chief Civil and Engineering Mechanics Section Mechanical and Civil Engineering Branch Division of Engineering
SUBJECT:	REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE MCGUIRE/CATAWBA NUCLEAR STATION APPLICATION FOR RENEWED OPERATING LICENSES (TAC NOS.: MB 2037, MB 2038, MB 2027, MB 2028)

By letter dated June 14, 2001, Duke Power submitted for EMCB view an application pursuant to 10 CFR Part 54, to renew the operating license for McGuire Nuclear Station, Units 1 and 2, and Catawba Nuclear Station, Units 1 and 2. The NRC staff and its contractor, Pacific Northwest National Laboratory (PNNL) have reviewed the information contained in the license renewal application and have identified, in the attachment, areas where additional information is needed to complete its safety review of the auxiliary systems section of the license renewal application.

The staff reviewed applicable systems described in Tables 3.3-1 through 3.3-47 of the application to determine whether the licensee provided adequate information to meet the requirements of 10 CFR Part 54.4 for managing the aging effects of the auxiliary systems for license renewal.

Attachment: As stated

Docket Nos: 50-369, 50-337, 50-413, 50-414

CONTACT: Bart Fu, EMCB/DE
415-2467

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REQUEST FOR ADDITIONAL INFORMATION
REVIEW OF THE MCGUIRE/CATAWBA NUCLEAR STATION
LICENSE RENEWAL APPLICATION

The applicant for McGuire/Catawba NPPs described its aging management review (AMR) of the auxiliary systems in Section 3.3, "Aging Management of Auxiliary Systems" of the license renewal application (LRA). The staff reviewed applicable systems described in Tables 3.3-1 through 3.3-47 of the application to determine whether the licensee provided adequate information to meet the requirements of 10 CFR Part 54.4 for managing the aging effects of the auxiliary systems for license renewal.

Based on the staff review of the applicant's submittal, all information was found to be adequate to address aging management of these systems with the exception of the following.

Section 3.3 "Aging Management of Auxiliary Systems"

Auxiliary Systems (General)

RAI-3.3.1

Tables 3.3-1 through 3.3-47 do not address the aging effect of loss of material and crack initiation and growth for closure bolting in these systems. Identify where in the LRA is the AMR for closure bolting, which is exposed to air, moisture, and leaking fluid (boric acid) environments, or provide a justification for excluding the bolting from Tables 3.3-1 through 47 and an AMR.

RAI-3.3.2

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 design, 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. Identify where in the LRA is the AMR for the aging effects of hardening and loss of material to elastomer component, or provide a justification for excluding them from tables for the numerous Section 3.3 ventilation systems and their associated AMR.

RAI-3.3.3

Clarify whether any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I SSCs as described in position C.2 of Regulatory Guide 1.29. Also, clarify how the aging management programs provided in tables of the LRA Section 3.3 apply to those seismic II over I piping system to assure 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.

Attachment

RAI-3.3.4

Appendix B, "Table of Contents" does not include the "Heat Exchanger Preventive Maintenance Activities and Diesel Generator Engine Cooling Water AMP." The AMP can be found on page 3.17-12 of Appendix B. Provide a reference to the heat exchanger preventive maintenance activities and diesel generator engine cooling water in Appendix B or the Table of Contents.

Auxiliary Building Ventilation System

RAI-3.3-1.1

Section 2.3.3.1, "Auxiliary Building Ventilation," states that the auxiliary building ventilation system maintains the ECCS pump rooms at negative pressure during ESF actuation. It lists the safety injection pump room and the centrifugal charging pump room as areas included within the scope of license renewal. Identify where in the LRA is the AMR for the motor air-handling units, which are responsible for maintaining this negative pressure to the safety injection and centrifugal charging pump rooms, or provide a justification for excluding these components from Table 3.3-1 and an AMR.

RAI-3.3-1.2

In Table 3.3-1 Column 2 (Component Function), the abbreviation "HT" is used in conjunction with several component types; however, "HT" is not defined in the notes at the end of Table 3.3-1. Provide a definition for this abbreviation, or justify why no definition is required.

Boron Recycle System

RAI-3.3-2.1

Table 3.3-2 has a "Note (3)," which implies that portions of the boron recycle system may be subject to alternate wetting and drying; however, this note is not used anywhere in the table. Clarify if Note (3) is applicable to Table 3.3-2. If so, explain how this environment and associated aging effects are managed in the LRA.

RAI-3.3-2.2

Table 3.3-2 Note (1) contains a definition of a component function "HT"; however, there are no components in Table 3.3-2 listed as performing this function. Identify components in the boron recycle system that provide the function "HT," or remove the function from Note (1).

Component Cooling Water System

RAI-3.3-6.1

In Table 3.3-6 the KC heat exchanger channel head has a carbon steel internal water environment exposed to raw water. Typically, the aging effect, fouling, is associated with raw water environments. Explain why fouling is not identified as an applicable aging affect to this component.

RAI-3.3-7.1

Table 3.3-7 KC heat exchanger tube sheet has an internal environment of raw water, but fouling is not identified as an aging effect. The aging effect, fouling, is typically associated with raw water environments. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-7 and an AMR.

RAI-3.3-7.2

Table 3.3-7 NC pump upper and lower motor bearing coolers have a treated water internal environment with an oil external environment. No aging effect is identified for this environment. Oil systems subject to water contamination are typically subject to the aging effect loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to carbon steel for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-7 and an AMR. (Note: This issue is common to all oil coolers so far reviewed in the LRA.)

Condenser Circulating System

RAI-3.3-8.1

Per Table 3.3-8 the Catawba and Maguire carbon steel condenser circulating water system components are subject to an internal environment of raw water. Explain why the aging effect of fouling has not been identified in Table 3.3-8 for pipe, pump casings, strainers, and valve bodies in a raw water environment.

Containment Ventilation System

RAI-2.3.3.7-1

Section 2.3.3.7, "Containment Ventilation System," of the applicant's LRA states that, with the exception of McGuire plant RTDs that are required for post-accident monitoring, the containment ventilation systems for McGuire/Catawba plants do not meet the license renewal scoping criteria. Industry experience has shown that degradation or other problems with the containment ventilation system may have detrimental effects on containment, vital equipment, and vital instrumentation within containment. Identify where in the LRA is the AMR for the aging effects to the containment ventilation system, or provide additional justification for excluding this system from an AMR.

Control Area Chilled Water System

RAI-3.3-9.1

Tables 3.3-9 and 3.3-10 credits the AMP, "Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program," for managing the aging effects of fouling and loss of material for copper-nickel alloy materials. The Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program, as defined in Appendix B of the applicant's LRA, manages for the loss of material or fouling for admiralty brass, carbon steel, and stainless steel materials; but Appendix B's description does not include the material copper-nickel within the scope of the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program. Explain how the Heat Exchanger Preventative Maintenance Activities - Control Area Chilled Water Program manages for the loss of material or fouling for copper-nickel alloy materials, or provide an AMP for managing these aging effects to this material.

RAI-3.3-9.2

Per Tables 3.3-9 and 3.3-10, the Catawba and Maguire control room area chillers (oil cooler tubes, tube sheets and shells) are subject to an internal/external environment of treated water/oil. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to carbon steel for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-9 and 3.3-10 and an AMR.

Diesel Building Ventilation Systems

RAI-3.3-13.1

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.

Diesel Generator Air Intake and Exhaust System

RAI-3.3.14-1

Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. Identify where in the LRA is the AMR for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting and crevice corrosion, or provide a justification for excluding this environment and aging effects from Table 3.3-14 and an AMR.

RAI-3.3.14-2

All of the components of Table 3.3-14, "Aging Management Review for Diesel Generator Air Intake and Exhaust System," are subject to an interior environment of Ventilation for Ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1609-5.0, CN-2609-5.0, MCFD-1609-5.00 and MCFD-2609-5.00, "Flow Diagrams for Diesel Engine Air Intake and Exhaust System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically these components are subject to a sheltered internal environment. Provide justification for classifying the internal environment for these components as "ventilation."

RAI-3.3.14-3

Table 3.5-2, "Aging Management Review Results for Other Structures," indicates rubber materials in a sheltered environment are subject to the aging effects of cracking and change in material properties. Explain why the rubber and composite rubber materials of Table 3.3-14, that are also in a sheltered environment, are not subject to the aging effects of cracking and change in material properties.

Diesel Generator Cooling Water System

RAI-3.3.15-1

Table 3.3-15, "Aging Management Review Results for Diesel Generator Cooling Water System (McGuire Nuclear Station)," states that aging effect loss of material in raw water environment to the diesel generator cooling water heat exchangers is managed by the AMP, "Galvanic Susceptibility Inspection." The scope of this program, as defined in Appendix B, Section B.3.16, does not include the diesel generator cooling water heat exchangers. Does the AMP, "Galvanic Susceptibility Inspection," manage the aging effects to the diesel generator cooling water heat exchangers? If not, identify an appropriate AMP.

RAI-3.3.15-2

Catawba plant flow diagrams, CN-1609-1.0, CN-2609-1.0, "Diesel Generator Engine Cooling Water System," indicate that the jacket water heaters are subject to aging management review. Identify where in the LRA the AMR for diesel jacket water heaters is, or provide a justification for excluding these heaters from Table 3.3-16 and an AMR.

RAI-3.3.15-3

The Catawba D/G governor lube oil coolers (tubes) are subject to an internal/external environment of treated water/oil. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-16 and an AMR.

Diesel Generator Fuel Oil System

RAI-3.3.18-1

In Tables 3.3-18 and 3.3-19, "Aging Management Review Results for Diesel Generator Fuel Oil System," the Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection is credited as managing the aging effect loss of material for the underground portion of the D/G fuel oil storage tanks. Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection mentions the diesel fuel oil system in the scope, but provides no details of the D/G fuel oil storage tanks inspection. (The Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection requires an internal inspection of the coating of the condenser circulating water piping.) Provide details of the inspection of the D/G fuel oil system storage tanks.

RAI-3.3.18-2

In Tables 3.3-18 and 3.3-19, "Aging Management Review Results for Diesel Generator Fuel Oil System," the Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection is credited as managing the aging effect loss of material and cracking for the underground portion of the diesel fuel oil system SS piping and valves. Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection mentions the diesel fuel oil system in the scope, but provides no details of the D/G fuel oil system piping and valve inspections. (The Preventive Maintenance Activities for Condenser Circulating Water System Internal Coating Inspection requires an internal inspection of the coating of the condenser circulating water piping.) Provide details of the inspection of the D/G fuel oil system piping and valves.

RAI-3.3.18-3

CN-2609-3.1, "Flow Diagram of Diesel Generator Engine Fuel Oil System (FD)," depicts piping from valve 2FD41 to valve 2FD43 as not being within the scope of license renewal. These are Duke Class C (ASME Class 3) components. Identify where in the LRA is the AMR for piping from valve 2FD41 to valve 2FD43, or provide a justification for excluding this piping from Table 3.3-19 and an AMR.

Diesel Generator Lube Oil System

RAI-3.3.20-1

Table 3.3-20, "Aging Management Review Results for Diesel Generator Lube Oil System," lists a material BR. Provide an explanation for the material BR in the Notes section to Table 3.3-20.

RAI-3.3.20-2

Tables 3.3-20 and 3.3-21, "Aging Management Review Results for Diesel Generator Lube Oil System (McGuire Nuclear Station)," states that the aging effect of cracking and loss of material in a lube oil environment is managed by the AMP, "Chemistry Control Program." The scope of this program as defined in Appendix B, Section B.3.6, only refers to fuel oil environments and not lube oil. Does the AMP, "Chemistry Control Program," manage the aging effects in lube oil environments? If not, identify an appropriate AMP.

RAI-3.3.20-3

In Tables 3.3-16, 3.3-20 and 3.3-21, "Aging Management Review Results for Diesel Generator Lube Oil System," the D/G engine lube oil coolers (tubes, tube sheets and/or shells) are listed as subject to an internal/external environment of treated water/oil. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Tables 3.3-20 and 21 and an AMR.

Diesel Generator Room Sump Pump System

RAI-3.3-22-1

Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System," states that orifices provide the function "PB." Typically, orifices also provide the function listed in Note 1 as "TH." Explain why orifices in the diesel generator room sump pump system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-22.

RAI-3.3-22-2

Table 3.3-22, "Aging Management Review Results for the Diesel Generator Room Sump Pump System," has a "Note (3), which implies that portions of the diesel generator room sump pump system may be subject to alternate wetting and drying; however, this note is not used in the table. Clarify if note (3) is applicable to Table 3.3-22. If so, explain how this environment and associated aging effects are managed in the LRA.

Diesel Generator Starting Air System

RAI-3.3.24-1

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies only a PB function for the D/G engine starting air aftercooler tubes. Explain why the heat transfer (HT) function, which ensures the system and/or component operating temperatures are maintained, is not considered in the AMR, or correct the component functions for D/G engine starting air aftercooler tubes listed in Table 3.3-24.

RAI-3.3.24-2

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies that the D/G engine starting air aftercooler tubes are stainless steel and subject to loss of material from exposure to a raw water internal environment. Typically, the aging effect, fouling, is also associated with raw water environments. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

RAI-3.3.24-3

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies the Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air as the aging management program to manage the aging effects of loss of material in a raw water environment for the D/G engine starting air aftercooler tubes and channel head, but not the tube sheet which is Monel 400 material. Section 18.2.12.5, "Diesel Generating Starting Air," of the LRA credits this program for managing aging for carbon steel, stainless steel and Monel materials. Does the AMP, "Heat Exchanger Preventive Maintenance Program for Diesel Generator Starting Air," manage the aging effect loss of Monel 400 material to the D/G engine starting air aftercooler tube sheet exposed to a raw water environment? If not, identify an appropriate AMP for managing aging effects to the Monel 400 material.

RAI-3.3.24-4

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies several components where carbon steel is exposed to an air (moist) environment with no aging effects or aging management program required. Loss of material from general, pitting, and crevice corrosion is an applicable aging effect for carbon steel materials in air environments containing moisture. General corrosion results from chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. Identify where in the LRA is the AMR for these aging effects, or provide a justification for excluding this aging effect from Table 3.3-24 and an AMR.

RAI-3.3.24-5

Table 3.3-24, "Aging Management Review Results for the Diesel Generator Starting Air System - Catawba," identifies environments air (dry) and air (moist) as potential environments for the diesel generator starting air system. Descriptions for these environments are not provided in Section 3.3.1 "Aging Management Review Results Tables," of the LRA. Identify where in the LRA these environments are defined, or provide additional information in Section 3.3.1 of the LRA.

Fire Protection System

RAI-3.3.26-1

Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire," indicates there is copper pipe material (CU) in the fire protection system. The notes at the end of the table do not include the material "CU." Correct the notes at the end of Table 3.3-26 to include the CU material designation or correct the table to identify the correct material designation.

RAI-3.3.26-2

Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire," indicate that sprinklers have a spray flow function. The last sprinkler component in Table 3.3-26 (page 3.3-164) is missing the SP designation. Correct the table, or justify why the spray flow function is not applicable to these sprinklers.

RAI-3.3.26-3

The fire protection program is credited in the LRA with managing the aging effect fouling in raw water environments for carbon steel, brass and bronze valves. In Table 3.3-26, "Aging Management Review Results for the Fire Protection System - McGuire," there are carbon steel, brass and bronze valve body components identified in the exterior fire protection section that do not include fouling as an aging effect. Identify where in the LRA is the AMR for the aging effects fouling to these components, or provide a justification for excluding this aging effect from Table 3.3-26 and an AMR.

RAI-3.3-26-4

Table 3.3-27, "Aging Management Review Results for the Fire Protection System - Catawba," indicates a Note (4) is applicable in several locations in the table where components experience the aging effect fouling. There is no definition for Note (4) at the end of Table 3.3-27. Clarify if note (4) is applicable to Table 3.3-27. If so, explain how this "alters" the established definition for the aging effect fouling.

RAI-3.3-26-5

Catawba drawings CN-1599-1.0 and MCFD-1599-01.00 identify the strainer components at the suction of the fire pumps to be within the scope of license renewal. These components are not included in Table 3.3-26 or 3.3-27. Identify where in the LRA is the AMR for strainers for the fire pumps, or provide a justification for excluding these strainers from Table 3.3-26 and 3.3-27 and an AMR.

Instrument Air System

RAI 3.3.31-1

Table 3.3-31, "Aging Management Review Results - Instrument Air System," identifies a component type of "FIV assured VI Supply Accumulators." Clarify what the acronym FIV stands for in the notes section of Table 3.3-31.

Liquid Waste System

RAI 3.3.32-1

Table 3.3-32, "Aging Management Review Results - Liquid Waste System," identifies stainless steel piping and loop seals at the McGuire plant that have the aging effects of loss of material and cracking due to exposure to wet/dry conditions. Identify where in the LRA the AMR for the wet/dry aging effect is and explain how it is managed by the chemistry control program, or provide a justification for excluding this environment/aging effect from Table 3.3-32 and an AMR.

RAI 3.3.32-2

Table 3.3-32, "Aging Management Review Results - Liquid Waste System," identifies the aging effects of loss of material and cracking in stainless steel due to exposure to wet/dry conditions. Clarify if this aging effect is also applicable to the sump pump components identified in Table 3.3-32.

Nuclear Service Water System

RAI 3.3.36-1

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," centrifugal and reciprocating charging pumps and safety injection pump oil coolers (tubes and tube sheets) have a raw water internal/external environment with an oil internal/external environment. No aging effect is identified for these environments. Oil systems subject to water contamination are typically subject to the aging effect loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion to stainless steel and copper-nickel materials for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-2

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the copper-nickel centrifugal and reciprocating charging pump and safety injection pump bearing oil cooler and centrifugal charging pump speed reducer oil cooler tubes are subject to an internal environment of raw water. Identify where in the LRA is the AMR for the aging effect of selective leaching for copper-nickel components in a raw water environment, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-3

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the Maguire carbon steel and stainless steel nuclear service water system components are subject to an internal environment of raw water. Identify where in the LRA is the AMR for the aging effect of fouling for stainless or carbon steel tube sheets, channel covers, expansion joints, orifices, tubing, pipe, pump casings, strainers, and valve bodies in a raw water environment , or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR

RAI 3.3.36-4

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the copper-nickel reciprocating charging pump bearing oil cooler and fluid drive oil cooler tubes are subject to an internal environment of raw water. Identify where in the LRA the AMR for the aging effect of fouling for the copper-nickel tubes in a raw water environment is, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-5

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the cast iron reciprocating charging pump fluid drive oil cooler channel covers are subject to an internal environment of raw water. Identify where in the LRA the AMR for the aging effect of selective leaching for cast iron components in a raw water environment is, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-6

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the bronze reciprocating charging pump bearing fluid drive oil cooler tube sheets are subject to an internal environment of raw water. Identify where in the LRA is the AMR for the aging effect of fouling for the bronze tube sheets in a raw water environment, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-7

Per Table 3.3-36, "Aging Management Review Results - Nuclear Service Water System (McGuire Nuclear Station)," the cast iron reciprocating charging pump bearing fluid drive oil cooler channel covers are subject to an internal environment of raw water. Identify where in the LRA the AMR for the aging effect of fouling for the cast iron channel covers in a raw water environment is, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-8

Per Table 3.3-37, "Aging Management Review Results - Nuclear Service Water System (Catawba Nuclear Station)," the Catawba carbon steel and stainless steel nuclear service water system components are subject to an internal environment of raw water. Identify where in the LRA is the AMR for the aging effect of fouling for stainless or carbon steel annubars, flexible hoses, orifices, tubing, pipe, pump casings, strainers, and valve bodies in a raw water environment, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

RAI 3.3.36-9

CN-1574-1.0 and CN-1574-1.2, "Flow Diagram of Nuclear Service Water System (RN)," indicate 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.

RAI 3.3.36-10

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.

RAI 3.3.36-11

CN-1574-2.5, "Flow Diagram of Nuclear Service Water System (RN)," indicates the component cooling water heat exchangers are not within the scope of license renewal. This appears to be an omission from the flow diagram. The component cooling water heat exchangers appear to be addressed in Table 3.3-7, "Aging Management Review Results - Component Cooling System." Verify that the component cooling water heat exchangers identified on CN-1574-2.5 are addressed in the LRA, or provide a justification for excluding these components from the LRA and an AMR.

RAI 3.3.36-12

Loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel materials in a raw water environment. Pitting corrosion can be inhibited by maintaining an adequate flow rate, which prevents impurities from adhering to the material surface. The more susceptible locations for pitting corrosion to occur in materials in a raw water environment are locations of low or stagnant flow. Identify where in the LRA the AMR for the aging effect of pitting corrosion is in low flow or stagnant conditions, or provide a justification for excluding this aging effect from Table 3.3-36 and an AMR.

Reactor Coolant Pump Motor Oil Collection Subsystem

RAI 3.3.40-1

Per Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System," flexible hoses are of the material type of stainless steel. Per CN-1553-1.3 and CN2553.1-3, "Flow Diagram of Reactor Coolant System (NC)," line listings for the flexible hoses between the upper bearing oil enclosures and the reactor coolant pump motor drain tank are carbon steel. Identify where in the LRA is the AMR for the reactor coolant pump motor oil collection sub-system carbon steel flexible hoses, or provide a justification for excluding these components from Table 3.3-40 and an AMR.

RAI 3.3.40-2

Per Table 3.3-40, "Aging Management Review Results - Reactor Coolant Pump Motor Oil Collection Sub-System," all components are subject to an internal environment of ventilation and an external environment of reactor building or ventilation. Explain why these components of the reactor coolant pump motor oil collection sub-system are not subject to an internal and/or external environment of oil.

Reactor Coolant System (Non-Class1 Components)

RAI 3.3.41-1

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

RAI 3.3.41-2

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

RAI 3.3.41-3

Per Table 3.3-41, "Aging Management Review Results - Reactor Coolant System (Non-Class1 Components)," Note 3, orifices may be subjected to a borated water or steam environment. Identify where in the LRA is the AMR for the reactor coolant system orifices in a borated water or steam environment, or provide a justification for excluding these environments from Table 3.3-41 and an AMR.

Standby Shutdown Diesel System

RAI 3.3-44.1

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator," identifies that the cooling water and jacket water engine radiator heat exchanger has a function of HT that is managed by the AMP, "Chemistry Control Program." Heat transfer monitoring is not identified as a capability of the chemistry control program, as defined in Appendix B, Section B.3.6. Explain how the chemistry control program monitors the heat transfer function.

RAI 3.3-44.2

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System," does not list an internal environment, which has the potential for exposure of components to hot diesel engine exhaust gasses containing moisture and particulates. Identify where in the LRA is the AMR for steel components exposed to a hot diesel exhaust environment that have the potential for experiencing loss of material from general, pitting, and crevice corrosion, or provide a justification for excluding this environment and aging effects from Table 3.3-44 and an AMR.

RAI 3.3-44.3

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Exhaust Sub-System," components are subject to an interior environment of ventilation, which is defined as ambient air that is conditioned to maintain a suitable environment for equipment operation and personnel occupancy. CN-1560-1.0, CN-1560.20, MCFD-1560-1.00, MCFD-1560.20, and MCFD-1614-4, "Flow Diagrams for Standby Shutdown Diesel System," do not include equipment to condition the intake air or the exhaust air for the diesels to provide a ventilation internal environment. Typically, these components are subject to a sheltered internal environment. Provide justification for classifying the internal environment for these components as "ventilation."

RAI 3.3-44.4

Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Fuel Oil Sub-System," identifies that the shutdown diesel generator fuel oil valve bodies, fuel oil (duplex filters) (CNS only) (p 3.3-254) has a "PB" component function. This component also provides filtration of process fluids so that downstream equipment and/or environments are protected. Explain why this component does not have a "FI" component function as defined in the notes section for other AMR tables, or correct the component functions for filters listed in Table 3.3-44.

RAI 3.3-44.5

In Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Fuel Oil Sub-System," the AMP Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection is credited as managing the aging effect loss of material for the underground portion of the standby diesel fuel oil storage tanks. Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection lists the diesel fuel oil system as being within the scope of the LRA, but provides no details of the standby diesel fuel oil storage tanks inspection. (The Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection requires an internal inspection of the coating of the condenser circulating water piping.) Provide details of the inspection of the standby diesel fuel oil system storage tanks.

RAI 3.3-44.6

In Table 3.3-44, "Aging Management Review Results - Standby Shutdown Diesel Generator, Fuel Oil Sub-System," the AMP Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection is credited as managing the aging effect loss of material and cracking for the underground portion of the diesel fuel oil system SS valves and piping for the McGuire plant. Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection lists the standby diesel fuel oil system as being within the scope of the LRA, but provides no details of the standby diesel fuel oil system valve inspections. (The Preventive Maintenance Activities - Condenser Circulating Water System Internal Coating Inspection requires an internal inspection of the coating of the condenser circulating water piping.) Provide details of the inspection of the SS standby diesel fuel oil system valves and piping.

Waste Gas System

RAI 3.3-47.1

Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies the hydrogen recombiner heat exchanger tubes as having a function of heat transfer. The chemistry control program, as described in Appendix B of the LRA, Section B.3.6, is identified as the aging management program. The stated purpose of chemistry control program in Appendix B is to manage loss of material and/or cracking of components. The program description does not include managing for the component function of heat transfer. Explain how the chemistry control program manages the heat transfer function..

RAI 3.3-47.2

Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies an internal environment described as gas. The definition for air-gas environments identified at the beginning of the tables does not adequately describe the gas environment found in the waste gas system. The waste gas system contains mixed radioactive fission gases (e.g., Kr, Xe, I, Cs) in addition to those listed in the air-gas definition. Clarify if the air-gas environment described at the beginning of the tables includes fission gases or add a new definition for the gas environment found in the waste gas system.

RAI 3.3-47.3

Table 3.3-47, "Aging Management Review Results - Waste Gas System," identifies that for the Catawba plant, the orifices for waste gas compressor seal and make-up have a pressure boundary "PB" component function. Typically, orifices also provide the function listed as "TH" (provide throttling so that sufficient flow and/or sufficient pressure is delivered, provide backpressure, provide pressure reduction, or provide differential pressure). Explain why orifices in the Catawba waste gas system do not provide the function "TH," or correct the component functions for orifices listed in Table 3.3-47.

From: Rani Franovich
To: Bob Gill
Date: 11/25/01 2:08PM
Subject: Fuel handling Area/Building Ventilation

Hi Bob,
I just noticed that Table 3.3.28 of the LRA is titled "AMR - Fuel Handling Building Ventilation." Is this table shared with the Catawba Fuel Handling Area Ventilation system (as implied on p. 3.3-1)?
Thanks-
Rani

From: Rani Franovich
To: Bob Gill
Date: 11/25/01 3:50PM
Subject: RAIs on TLAAs

Hi Bob,
I have attached some questions on TLAAs. Note that we have already discussed some of these questions.

Questions from Section 4.3, Metal Fatigue, were discussed with John Fair on August 8. The conference call was not documented because we all agreed that the questions would be sent as formal RAIs. However, if you think a call will be successful in resolving any of John's questions, we can certainly schedule one.

Also, Section 4.6 was discussed on November 20 (last Tuesday). Those questions and your responses have been documented; I'm waiting for mark Hartzman to proide comments to me so I can forward it to you.

The remaining TLAA questions may not have been seen previously by you. Perhaps an electronic reply that I can forward to the reviewer (as you have dome previously) would be a good first step to deciding if a conference call is needed or would be helpful. I know you have a full plate, so let me know what you think when you get to this one...

Thanks-
Rani

September 25, 2001

MEMORANDUM TO: Christopher I. Grimes, Chief
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs

FROM: Kamal A. Manoly, Chief ***/RA/***
Civil and Engineering Mechanics Section
Mechanical and Civil Engineering
Division of Engineering

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE CATAWBA/MCGUIRE NUCLEAR PLANTS LICENSE RENEWAL APPLICATION (TAC NOS. MB2037, MB2038, MB2027 AND MB2028)

The NRC staff has reviewed the information relevant to the aging management reviews (AMRs) that were included in the license renewal application (LRA) for the Catawba/McGuire Nuclear Plants. The staff has identified that additional information is needed to complete the review of the subject LRA. The staff's request for additional information (RAI) is attached.

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

Attachment: As stated

Contact: Jai Rajan, DE/EMEB
415-3306

MEMORANDUM TO: Christopher I. Grimes, Chief
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs

FROM: Kamal A. Manoly, Chief
Civil and Engineering Mechanics Section
Mechanical and Civil Engineering
Division of Engineering

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE CATAWBA/MCGUIRE NUCLEAR PLANTS LICENSE RENEWAL APPLICATION (TAC NOS. MB2037, MB2038, MB2027 AND MB2028)

The NRC staff has reviewed the information relevant to the aging management reviews (AMRs) that were included in the license renewal application (LRA) for the Catawba/McGuire Nuclear Plants. The staff has identified that additional information is needed to complete the review of the subject LRA. The staff's request for additional information (RAI) is attached.

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

Attachment: As stated

Distribution:
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M. Khanna
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R. Franovich

ADAMS ACCESSION NUMBER:

OFFICE	DE/EMEB	DE/EMEB
NAME	J. Rajan	K. Manoly
DATE	9 / 14 /2001	9 / 25 /2001

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MECHANICAL ENGINEERING BRANCH
REQUEST FOR ADDITIONAL INFORMATION
CONCERNING MCGUIRE AND CATAWBA
LICENSE RENEWAL APPLICATION
SECTION 4.0 TIME-LIMITED AGING ANALYSIS

4.1 IDENTIFICATION OF TIME-LIMITED AGING ANALYSES TLAAs

RAI 4.1.1-1

Section 4.1.1 of the LRA discusses the background related to the identification of TLAA applicable to both McGuire and Catawba Nuclear stations. Your application was not specific in regard to the applicability of certain TLAAs to a specific station. We request that you provide the following information as required by 10 CFR 54.21(c), and identify for which station the listed TLAA is applicable:

a. A list of time-limited aging analyses provided as part of the LRA.

b. Identify the method of resolution in accordance with 10 CFR 54.21(c)(1) for each TLAA category.

4.3 METAL FATIGUE

RAI 4.3.1-1

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:

a. 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.

b. 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.

RAI 4.3.1-2

The Westinghouse Owners Group issued Topical Report WCAP-14577, Revision 1-A, "Aging Management for Reactor Internals," to address the aging management of the 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.

RAI 4.3.1-3

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.

RAI 4.3.1-4

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 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 exceed 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:

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

b. 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.

c Discuss the impact of the environmental fatigue correlations provided in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," on the above results.

RAI 4.3.1-5

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 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:

a. 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.

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

c. 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.

d. 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.

RAI 4.3.1-6

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:

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

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

c 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]).

d. 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.

RAI 4.3.2-1

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.

4.6 CONTAINMENT LINER PLATE, METAL CONTAINMENTS, AND PENETRATION FATIGUE ANALYSES

RAI 4.6.2-1

4.6.1 Section 4.6.2 "Metal Containments" refers to Section 3.9.2.8 of the McGuire UFSAR and Section 3.4.2.4 of the Catawba UFSAR. These sections state that mechanical penetrations are treated as fabricated piping assemblies meeting the requirements of ASME Section III Section NC and which are assigned the same classification as the piping system that includes the assembly i.e., Class A through H as defined in Table 3.5. of the UFSAR. Provide the following information:

a. Indicate if there are Duke Class A piping systems penetrating the containment.

b. Table 3.5 of the UFSAR indicates that the applicable code design criteria for Duke Class A piping is ASME Section III, Class 1, 1971. If the response to item a. is affirmative, provide justification for designing the Duke Class A piping containment mechanical penetrations to the requirements of ASME Section III, Subsection NC.

4.6.2 In Sections 4.6.3.1 "McGuire Design and Time-Limited Aging Analysis Evaluation" and 4.6.3.2 "Catawba Design and Time-Limited Aging Analysis Evaluation," provide the basis for the concluding that Criterion (4) of §54.3 is not met, i. e., the determination that bellows fatigue analyses at the McGuire and Catawba plants are not relevant in making any safety determination.

4.6.3 Sections 4.6.3.1 "McGuire Design and Time-Limited Aging Analysis Evaluation" and 4.6.3.2 "Catawba Design and Time-Limited Aging Analysis Evaluation," refer to cracking as an aging effect which could result from cyclic fatigue, requiring management for the bellows for the period of extended operation. "The Containment Leak Rate Testing Program," discussed in Section B.3.8, has been identified as the program that manages cracking of the bellows. The element, "McGuire Operating Experience," in Section B.3.8 states that several leaking penetration bellows were identified after twenty years of operation, and that some are currently cracked but the test leakages are within Technical Specification limits. Provide the following information:

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

b. For the McGuire and the Catawba plants, provide the number of bellows that are cracked under current operating conditions and meet the Technical Specification leakage limit.

c. For the currently existing cracked bellows in the McGuire and the Catawba plants, provide assurance that the size of the cracks will not exceed the crack size corresponding to the maximum allowable leakage rate La before the next scheduled leakage rate test.

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 .

4.7.3 DEPLETION OF NUCLEAR SERVICE WATER POND VOLUME DUE TO RUN OFF

RAI 4.7.3-1

It is stated in Section 4.7.3 of the LRA that your recent calculations have validated the adequacy of the volume of water in the SNSWP. However, your application is silent about the remedial action you will take in case a future survey of the topography of the bottom of the Pond indicates a reduction in the volume of water due to the buildup of sediment. Clarify this aspect of your SNSWP Volume Program.

From: "Robert L Gill Jr" <rlgill@duke-energy.com>
To: "Rani Franovich" <RLF2@nrc.gov>
Date: 11/26/01 12:40PM
Subject: Re: Plant EFPY

Sorry for the delay. Here are the current EFPY values for McGuire and Catawba:

MNS Unit 1 - 13.71 EFPY
MNS Unit 2 - 13.08 EFPY

CNS Unit 1 - 12.95 EFPY
CNS Unit 2 - 12.02 EFPY

Bob

"Rani Franovich" <RLF2@nrc.gov>
11/15/2001 08:30 AM

To: <rlgill@duke-energy.com>
cc: "Lambros Lois" <LXL1@nrc.gov>
bcc:
Subject: Plant EFPY

Bob,
I have a request from a reviewer who wants to know what the current EFPY values are for the 4 Duke units (Catawba and McGuire). Can you provide that to us or refer us to some docketed correspondence that contains that information?
Thanks-
Rani

CC: "Lambros Lois" <LXL1@nrc.gov>, "Mary H Hazeltine" <mhhazelt@duke-energy.com>

From: Rani Franovich
To: Bob Gill
Date: 11/27/01 9:57AM
Subject: Summary of October 25 Conference Call on Mechanical AMPs

Bob,
Atteched is a summary of the call we had. I am still waiting for my technical monitor to check with the contractor on some of the items in red. The only red item I need clarification from you on is the plant/unit distinction. Comments are welcome, as always.
Thanks-
Rani

LICENSEE : Duke Energy Corporation

FACILITIES: McGuire, Units 1 and 2, and Catawba, Units 1 and 2

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON AGING MANAGEMENT PROGRAMS FOR MECHANICAL SYSTEMS AND COMPONENTS

On October 25, 2001, after the NRC (the staff) reviewed information provided in Appendix B of the license renewal application (LRA), a conference call was conducted between the staff and Duke Energy Corporation (the applicant) to clarify information presented in the application pertaining to aging management programs for mechanical systems and components. Participants in the conference call are provided in an attachment.

The questions asked by the staff, as well as the responses provided by the applicant, are as follows:

B.3.4 Borated Water Systems Stainless Steel Inspection

1. The LRA proposes that one of twelve possible inspection locations at each plant will be inspected volumetrically as part of the Borated Water Systems Stainless Steel Inspection program (monitoring & trending). Stainless steel (SS) has demonstrated susceptibility to intergranular stress corrosion cracking (IGSCC) in low-temperature borated water systems in pressurized water reactors, particularly in stagnant lines, at weld heat-affected zones (HAZs), involving weld procedures that resulted in sensitization of the stainless steel in the HAZs. Since IGSCC has a wide range of induction and propagation rates, depending on degree of sensitization, local stresses, and specific impurities at a given location, justify why only a one-time inspection is sufficient. Also, since not all welds, stress patterns, and impurity levels and species are necessarily similar, justify why inspection of only one of twelve locations adequately represents the durability of material at the other eleven locations and explain the process for inspection population expansion should aging effects be identified.

   The applicant indicated that the containment spray piping is essentially the same (material and environment) at each plant (or unit?? Bob, can you answer?), such that one spray pipe is representative of all twelve. As such, if no parameters are known that would distinguish certain locations at each site as being more susceptible to loss of material or cracking, one location will be chosen based upon radiological conditions and accessibility. The applicant also indicated that the staff previously found this aging management program acceptable, as documented in the safety evaluation report for the staff's review of the Oconee LRA. The staff will consider the information provided in the applicant's response, but may request additional information to complete its review of this item.

2. The LRA proposes that a one-time inspection be performed and that no actions are to be taken to trend inspection results (monitoring & trending). The LRA also states that if an engineering evaluation determines that the aging effects, identified during the one-time inspection, will not result in a loss of the component's intended function(s) during the period of extended operation, then no further action will be required. Industry operating experience has shown that, under this environment, stress-corrosion cracking tends to result in leaks that are somewhat localized. In this light, explain the basis for not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending).

   The applicant indicated that engineering judgment would be applied to determine if corrective actions are warranted based upon the results of the one-time inspection. Provisions for programmatic oversight would be established at the time the results of the inspection are obtained, and the inspection results, as well as corrective actions taken by the applicant (licensee), would be subject to NRC inspection at the appropriate time in the future. The staff will consider this information but may request additional information to determine the appropriateness of not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending). In addition, the staff may request that the applicant describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

3. The LRA states that the parameters inspected by the borated water systems stainless steel inspection program are pipe wall thickness, as a measure of loss of material, and evidence of cracking (parameters monitored or inspected). Will the inspections also be looking for evidence of pitting? If so, discuss the inspection technique(s) that will be used to reliably identify the presence of pits (monitoring & trending).

   The applicant indicated that the volumetric technique (ultrasonic testing) would reveal loss of material from pitting. The staff is satisfied with this response but may request this information formally.

<u>B.3.14 Flow Accelerated Corrosion Program</u>

1. The LRA states that the inspection frequency for each location will vary and depend on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experience (monitoring and trending). Identify the predictive model(s) that will be used to predict component degradation in the systems conducive to flow accelerated corrosion and the inspection schedules necessary to provide reasonable assurance that the structural integrity will be maintained between inspections. Also discuss how these models have been benchmarked.

The applicant indicated that the predictive model to be used is CHECWORKs, and that the inspection schedules would be determined in accordance with EPRI document NSAC-202L based upon inspection results and wear rate, as documented in the LRA under Section B.3.14, Flow Accelerated Corrosion Program. The staff is satisfied with this response and has no additional questions on this issue.

2. Describe the basis for location sampling and the provisions for expanding the inspection scope (i.e., additional examinations) in the event that degradation is detected that exceeds the acceptance criteria (monitoring and trending).

   The applicant indicated that the basis for location sampling and the provisions for expanding the inspection scope is provided in the EPRI document, which is referenced in the Flow-Accelerated Corrosion program documented on page XI M-58 of the Generic Aging Lessons Learned (GALL) report. The staff is satisfied with this response and has no additional questions on this issue.

<u>B.3.15 Fluid Leak Management</u>

1. The program is stated to focus on carbon and low alloy steels (scope). There are several cases of failure of stainless steels in borated water systems, for example, spent fuel pool piping. Why is stainless steel not indicated as a relevant material?

   The applicant indicated that boric acid corrosion of stainless steel is not a plausible aging effect. The staff is satisfied with this answer and has no additional questions on this issue. Meena, the contractor indicated that their question was more along the lines of IGSCC of welds in stainless steel piping. I'd like to delete this RAI altogether (from the conference call summary as well) because, based on my reviews of B.3.6 and B.3.34, they have AMPs that address this. Can you suggest to them that they review B.3.6 and re-review B.3.34 to see if this question can be eliminated?

2. There is no mention of strategies that address leak management for component segments that are not accessible to visual inspection (monitoring and trending). Indicate whether there are provisions in the fluid leak management program for leak management in inaccessible locations.

   The applicant indicated that the condition of material in accessible areas is considered indicative of material in inaccessible areas. The staff will consider this information, but may request additional information to determine understand the applicant's response to Generic Letter 88-05, which contains provisions for inspecting inaccessible areas for boric acid corrosion.

<u>B.3.16 Galvanic Susceptibility Inspection</u>

1. The LRA states that the galvanic susceptibility inspection will inspect a select set of carbon steel-stainless steel couples at each site (monitoring and trending). Since the galvanic susceptibility inspections are one-time inspections of a given sample that are

intended to provide objective evidence that the applicable aging effects are being adequately managed, explain how the sample size will be selected in order to ensure that the inspection population is representative for all systems listed in the galvanic susceptibility inspection program scope.

The applicant indicated that a bounding approach will be used for the one-time inspection such that the worst-case combination of materials and environments will be inspected. Material and environment combinations that are less susceptible to galvanic corrosion will be inspected if the worst-case combinations reveal degradation. The staff will consider this information, but may request additional information to complete its review of this item.

2. In the LRA, provisions for sample size expansion and subsequent inspections, in the event that the initial inspection detects degradation, are not included (monitoring and trending). Provide justification for their exclusion. Otherwise, discuss the criteria that will be used and the procedure that will be implemented for expanding the sample size when degradation is detected in initial/subsequent inspections.

   The applicant indicated that the provisions for sample size expansion and subsequent inspections, in the event that the initial inspection detects degradation, are included in the discussion of corrective actions and confirmation process associated with the Galvanic Susceptibility Inspection. The staff is satisfied with this response and has no additional questions on this issue.

3. The LRA describes the acceptance criterion for the galvanic susceptibility inspections as "no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria that will be used to define "unacceptable loss of material" and how the acceptance criteria will ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Also, describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider the information provided in the applicant's response, but may request additional information to complete its review of this item.

4. The LRA states that "programmatic oversight" will be defined in the event that engineering evaluations determine that continuation of the aging effects could cause a loss of component intended function(s) under current licensing basis design conditions for the period of extended operation (corrective action and confirmation). Explain what programmatic oversights will need to be defined in order to implement corrective actions.

Clarify if these activities are related to the corrective actions program described in B.3.2.2 of the LRA.

The applicant indicated that the programmatic oversight will be defined at an appropriate time in the future when the results of the inspection can be considered to develop that oversight. The applicant also indicated that the corrective action process would be used to document the inspection results as well as the planned and completed actions (including programmatic oversight) taken to correct the degradation. The staff is satisfied with this response and has no additional questions on this issue.

5. The scope of the galvanic susceptibility inspection program is indicated to include all galvanic couples exposed to gas, unmonitored treated water, and raw water environments in the McGuire and Catawba systems listed (scope). However, the proposed implementation involves only measurements on carbon steel-stainless steel couples (parameters monitored or inspected), based on an assumption that this couple represents a worst case, based on expectations from the galvanic series (monitoring and trending). First, note that the relative position in the series can shift, depending on specific environments. Second, note that the position of stainless steel in the series depends on whether the material is active or passive. Third, as an example, copper alloys are listed as relevant materials. Could the CS/SS couple measurements provide favorable results that fail to address the galvanic phenomena that may be degrading other materials?

   The list of systems includes nuclear service water, which is large, complex, usually with multiple materials, subject to a variety of environments, that may change over time, including flowing and stagnant water, microbiological species, etc. The mechanisms include localized (e.g., pitting) and uniform corrosion. Given these complexities, justify that limiting the proposed inspections to carbon-stainless steel couples provides sufficient evidence in regards to the potential aging degradation of <u>all</u> galvanic couples in nuclear service water and other systems.

   The applicant indicated that raw water is the worst case, bounding environment for galvanic corrosion. The staff will consider this information, but may request additional information to complete its review of this item as well as Question 1 under B.3.16, Galvanic Susceptibility Inspection. Any future request for additional information on this issue will address both of these questions, if appropriate.

6. The LRA states that the parameter inspected by the galvanic susceptibility inspection program is pipe wall thickness (parameters monitored or inspected) and inspections will be performed using a volumetric examination technique. As an alternative, visual examination will be used should access to internal surfaces become available (monitoring and trending). Is it the intent to substitute the volumetric examination (wall thickness) with a visual examination for those components where access to the internal surfaces is available? If so, describe how section thickness will be determined.

   The applicant indicated that their intent was not to substitute a volumetric test with a visual inspection. The applicant acknowledged that a visual inspection does not provide the same level of confidence that a volumetric examination provides. The staff is satisfied with this response. However, since the LRA states that a visual inspection could be used as an alternative to volumetric testing, the staff will request this clarification formally from the applicant.

B.3.17 Heat Exchanger Activities

1. The approaches for heat exchanger performance testing at Catawba and McGuire involve flow monitoring using differential pressure tests (parameters monitored and inspected). Do the tests include converting mass flow to linear flow velocity to assure that flow regimes that promote flow-assisted corrosion are avoided? This is particularly important in systems involving admiralty brass, which has shown susceptibility to flow-induced corrosion in heat exchangers in power systems.

   The applicant requested the staff to review the aging management review tables to determine if any heat exchanger materials involve admiralty brass. The applicant also requested the staff to share with them the operating experience that indicates that admiralty brass, and any other material, is susceptible to flow-induced corrosion in heat exchangers so they can review the information for applicability to Catawba and McGuire. The staff will take these requests under consideration and incorporate specific references to industry operating experience into any future request for additional information on this issue.

2. The pressure differential test, while an indicator of fouling, does not directly address assurance of satisfactory heat transfer coefficients. It seems possible that relatively thin films may have poor heat transfer characteristics. Describe the monitoring and trending method or technique that will be used to ensure that the heat exchangers are capable of adequate heat transfer required to meet system and accident load demands.

   The applicant requested the staff to share with them the operating experience that involves the phenomenon of thin films that have poor heat transfer characteristics so they can review the information for applicability to Catawba and McGuire. The staff will either provide industry operating experience to the applicant for their review and determination of applicability, or the staff will reconsider its need for additional information to complete its review of this item.

3. The LRA states that the performance testing will monitor flow capacity by measuring the pressure drop through the component cooling heat exchanger tubes to identify the presence of fouling (parameters monitored or inspected). Will the monitoring and testing program for the component cooling heat exchangers also consider performance parameters on the shell side? If so, explain what parameters will be monitored. Describe how the parameters being monitored will indicate degraded heat transfer capabilities.

   The applicant indicated that treated water flows through the component cooling water heat exchanger shell and requested the staff to indicate if, perhaps, this question applies to other heat exchangers for which raw water flows through the shell. The staff (contractor) needs to review B.3.29, Service Water Piping Corrosion Program (which references GL 89-13), and determine if this question still applies.

B.3.22 Liquid Waste System Inspection (EMEB/Jain)

1. In section B.3.22 of the LRA, under monitoring & trending, the applicant stated that the selection of the specific areas for inspection for the system material/environment combinations will be the responsibility of the system engineer. Discuss the selection criteria that will be used by the system engineer for the inspection of the specific areas.

   The applicant suggested that the staff issue a request for additional information so that they can provide the selection criteria to the staff in their response.

2. The acceptance criterion for the liquid waste system inspection program is "no unacceptable loss of material and cracking of stainless steel components and loss of material of carbon steel and cast iron components that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider this information, but may request additional information to complete its review of this issue.

B.3.32 Sump Pump Inspection (EMEB/Rajan)

1. The acceptance criterion for the sump pump inspection program is "no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation." Describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider this information, but may request additional information to complete its review of this issue.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
License Renewal Project Directorate
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Attachment: As stated

cc w/attachment: See next page

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
License Renewal Project Directorate
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

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J. Wilson
C. Munson
M. Khanna
R. Elliott

Division of Regulatory Improvement Programs
COVER PAGE

DATE: November 14, 2001

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON AGING MANAGEMENT PROGRAMS FOR MECHANICAL SYSTEMS AND COMPONENTS

ORIGINATOR: R. Franovich

SECRETARY: S. Chey

●●●DRIP ROUTING LIST●●●		
	NAME	DATE
1.	EGHylton	/ /01
2.	RLFranovich	/ /01
3.	CIGrimes	/ /01

DOCUMENT NAME:C:\WINDOWS\TEMP\GWViewer\Conference Call Summary Oct 25 01 - Mechanical AMPs.wpd

ADAMS ACCESSION NUMBER: **ML** DATE ENTERED: / /01

<u>FORM 665</u> ATTACHED and filled out: **YES** **NO**

<u>COMMITMENT FORM</u> ATTACHED: **YES** **NO**

Mr. Gary Gilbert
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Duke Energy Corporation
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Piedmont Municipal Power Agency
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TELECOMMUNICATION PARTICIPANTS
OCTOBER 25, 2001

Staff Participants

Rani Franovich

Clifford Munson

Duke Energy Corporation Participants

Bob Gill

Rounette Nader

Mike Semmler

Attachment

From: "R Paul Colaianni" <rpcolaia@duke-energy.com>
To: <RLF2@nrc.gov>
Date: 11/26/01 2:53PM
Subject: Summary of Conference Call on November 13 - Electrical Aging Management

Rani,

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I typed them in WordPerfect to make your use of them easier.

Let me know if I can be of further help.

Sincerely,
Paul Colaianni
Senior Engineer, Duke Energy License Renewal Project
rpcolaia@duke-energy.com
704-382-5632
(See attached file: Electrical Conference Call Notes Nov 13, 2001.wpd)

----- Forwarded by R Paul Colaianni/Gen/DukePower on 11/26/2001 14:14 -----

Robert L Gill Jr
11/26/2001 07:02

To: R Paul Colaianni/Gen/DukePower@DukePower
cc:
bcc:
Subject: Summary of Conference Call on November 13 - Electrical Aging Management

Paul, please handle
----- Forwarded by Robert L Gill Jr/Gen/DukePower on 11/26/2001 07:02 AM -----

"Rani Franovich" <RLF2@nrc.gov>
11/23/2001 04:13 PM

To: <rlgill@duke-energy.com>
cc:
bcc:
Subject: Summary of Conference Call on November 13 - Electrical Aging Management

Hi Bob,
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C. referenced several sections or tables from a cable aging management guide that I don't have. Could I get him to summarize his response (including specific references) to that question and send it to me electronically? I may need a similar summary on his responses to B.3.19-1 and B.3.19-2. I think I can correctly characterize the other items. Thanks a bunch!
Rani

CC: "Robert L Gill Jr" <rlgill@duke-energy.com>

3.6.1.2.2-1 Discussion

GALL Report program XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits", uses routine calibration tests performed as part of the plant surveillance test program to identify the potential existence of aging degradation of cables and connections used in low-level signal applications that are sensitive to reduction in insulation resistance (IR) such as radiation monitoring and nuclear instrumentation. Program XI.E2 is based on the program implemented at Calvert Cliffs as documented in Section 3.12.3.2.3 of NUREG-1705, the Calvert Cliffs license renewal SER. Implementation of this program basically consists of flagging the specific plant calibration procedures.

GALL Report program XI.E2 pertains to instrumentation circuits that are sensitive to reductions in insulation resistance (IR). These are a subset of the cables covered by inspection program XI.E1 since both programs (XI.E1 and XI.E2) are identified in GALL Report Table VI.A (pages VI A-3 and A-4) as managing aging effects caused by heat and radiation that can lead to reduced insulation resistance (IR). According to GALL Report Table VI.A (page VI A-3), program XI.E1 manages "Aging Effects/Mechanisms" that lead to "reduced insulation resistance" with "Further Evaluation" not required.

Although credited during the Calvert Cliffs license renewal application review, other plants since have not credited this program for managing the effects of aging of circuits sensitive to a reduction in IR. This is likely due to the fact the inspection program XI.E1, which looks at mechanical and physical properties, is much more able to detect early material degradation than testing program XI.E2, which looks at electrical properties. As discussed in Section 5.2.2 of the DOE Cable AMG (underline added for emphasis):

> **DOE Cable AMG, Section 5.2.2, Measurement of Component or Circuit Properties**
> "Diagnostic techniques to assist in assessment of the functionality and condition of power plant cables and terminations are described in this section....
>
> "Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal- and radiation-induced aging. <u>For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical changes are observed</u>...."

Visual inspection can detect aging degradation early in the aging process whereas embrittlement and cracking must occur before significant electrical property changes, such as reduced insulation resistance, would be detected through circuit calibration.

Moisture intrusion was brought up as a concern that would be addressed by GALL Report program XI.E2. For low-voltage cables, embrittlement and significant cracking of the cable jacket and conductor insulation would have to occur before moisture could possibly be an issue. According to GALL Report Table VI.A (pages VI A-3 and A-4) moisture intrusion is an aging effect that is adequately managed by each program XI.E1 and X1.E2. The GALL Report does not indicate that both of these programs are needed to manage aging for the possibility of moisture intrusion. Each program is indicated as individually managing this possibility. GALL Report program XI.E1 is able to detect aging degradation sooner than program XI.E2 by monitoring mechanical physical property changes.

The industry understands that these two programs (XI.E1 and XI.E2) manage the same aging effects for the same cables in different ways. This is seen as providing an applicant with the ability to pick the program that best fits the needs identified at the plant, but that both programs would not be required to adequately manage aging of plant cables. This was illustrated by the first two applicants where Calvert Cliffs committed to the calibration program (XI.E2) but not to the inspection program and where Oconee committed to the inspection program (XI.E1) but not to the calibration program. This was the pattern or precedent that the industry saw and understood as being included in the GALL Report - two programs that cover the same cables using different methods to manage aging with the applicant able to choose a program that best fits the plant aging management needs.

B.3.19-1 and B.3.19-2 Discussion

Program XI.E3 identifies and tests medium-voltage cables that could be susceptible to aging effects caused by moisture and voltage stress. Program XI.E3 is based on the program implemented at Oconee as documented in Section 3.9.3.2.1 of NUREG-1723, the Oconee license renewal SER.

This program provides a good lesson in practicality. A practical way to implement this program and to provide the plant medium-voltage with the best assurance of uninterrupted function is to take rudimentary, preventive actions to ensure that the cables are not exposed to (as described in the Cable AMG) long-term, continuous (going on or extending without interruption or break) standing water. Although some installations (such as some conduit configurations) do not make it easy to determine if the cables are exposed to standing water, going to the trouble to find out is usually much easier and less costly than having such a cable fail at an inopportune time.

"Long-term" in the above paragraph is not defined. GALL Report program XI.E3 uses "periodic exposures to moisture that last more than a few days (e.g., cable in standing water)". The basis for defining significant moisture in terms of "a few days" is based in the Oconee license renewal application review as described below.

In order to resolve issues identified during the Oconee license renewal application review an aging management program was proposed for medium-voltage cables installed in conduit or direct buried that are exposed to significant voltage and significant moisture. Rather than leave the "significant" criteria undefined, which would be an implementation problem at the station, a search for quantitative criteria was performed. All available industry literature was reviewed including *Effects of Moisture on the Life of Power Plant Cables, Part 1: Medium-Voltage Cables, Part 2: Low-Voltage Cables* (EPRI report TR-103834-P1-2, August 1994) and industry experts were consulted. This research identified only subjective criteria. The industry literature provided the basis that medium-voltage cables could probably be exposed to standing water for several years without any problems. The main NRC staff concern at Oconee was an outside cable trench that had a low point in the plant where water would collect after every rain. The water collection was checked daily and drained if needed. The program was written to address the Oconee situation (rain and drain exposure) which was not seen as a problem. That's where "a few days" came in. This was a situation where checking frequently was normal procedure. Therefore, quantitative criteria were created based on the subjective criteria found in industry documents, and based on the specific Oconee installations under review.

Current license renewal applications being reviewed define long-term as "over a long period such as a few years". The industry data tends to validate that cables exposed for "a few years" should be fine. However, the amount of time mentioned in most documents is indeterminate on length of time. The current application for McGuire and Catawba uses "a few years" for practical, implementation reasons more than anything else.

Many medium-voltage cable installations that are possibly exposed to moisture are installed in safety-related trenches and manholes. In order to inspect portions of these trenches for water collection it is necessary to have a crane lift the covers due to their weight. Defining "long-term" as "a few days" would make it impossible to monitor water collection frequently enough to met the program requirements. The cable engineer would have to go out a few days after each rainfall in order to know if the cables are exposed to significant moisture. From the practical standpoint of implementing the program, defining long-term as "a few years" is a reasonable length of time that makes it possible to implement. This would be workable from an inspection standpoint and still well within the bounds of industry estimates on how long it takes for water trees to propagate to failure.

During a previous conference call on the issue it was expressed that one of the main NRC staff's concerns was that the program, as written, sounded like Duke thought it was fine if medium-voltage cables sat in water for several years. That is definitely not the case. The Duke staff believes that the most important point is to build a program that provides incentives for the plant to prevent the medium-voltage cables from being exposed to standing water for any appreciable length of time as this is the best way to prevent aging effects caused by moisture and voltage stress for medium-voltage cables. Defining "long-term" as "a few days" makes it impossible to check frequently enough and does not provide any incentive for finding and eliminating standing water around medium-voltage cables.

A suggestion made by NRC staff during one of the conference calls was to leave "a few years" as is but add language in the corrective actions that when medium-voltage cables are found to be in standing water that the problem is either fixed (i.e., fix the sump pump, fix the drains, etc) or increase the inspection frequency. In order not to be required to test the medium-voltage cables, inspections for standing water would have to be performed before the start of the renewal period. Assuming the corrective actions are enhanced as described, if medium-voltage cables are found exposed to standing water then the pump or drain would be fixed and/or the inspection frequency would be increased. This provides direct incentive for the plant to correct any water collection problems since the alternative is to test the cables, which is the least attractive alternative for the plant as this requires disconnection and retermination of the equipment.

From: Rani Franovich
To: R Paul Colaianni
Date: 11/28/01 9:50AM
Subject: Re: Summary of Conference Call on November 13 - Electrical Aging Management

Paul,
I have a question about one of the responses you sent. The question has to do with the following part of the response to B.3.19-1 and -2:

"The main NRC staff concern at Oconee was an outside cable trench that had a low point in the plant where water would collect after every rain. The water collection was checked daily and drained if needed. The program was written to address the Oconee situation (rain and drain exposure), which was not seen as a problem. That's where "a few days" came in. This was a situation where checking frequently was normal procedure. Therefore, quantitative criteria were created based on the subjective criteria found in industry documents, and based on the specific Oconee installations under review."

Ordinarily, I would go through Bob, but it is a simple clarification that should not take long and I know Bob is in a meeting this morning. If you feel comfortable calling me directly, that would be fine. My number is 301-415-1868.

Thanks,
Rani

>>> "R Paul Colaianni" <rpcolaia@duke-energy.com> 11/27/01 08:53AM >>>

Rani,
I actually prefer Word Perfect and use it for most non-work related tasks.

I keep a copy on my Duke computer especially because I know the NRC still uses it.

Sincerely,
Paul Colaianni

rpcolaia@duke-energy.com
704-382-5632
Lead Electrical Engineer
Duke Energy, Nuclear License Renewal Project

"Rani Franovich" <RLF2@nrc.gov>
11/26/2001 15:08

To: <rpcolaia@duke-energy.com>
cc: <rlgill@duke-energy.com>
bcc:
Subject: Re: Summary of Conference Call on November 13 - Electrical Aging Management

And even in Word Perfect. That must have been painful for you...
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(See attached file: Electrical Conference Call Notes Nov 13, 2001.wpd)

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Robert L Gill

Jr To: R Paul
Colaianni/Gen/DukePower@DukePower
cc:

11/26/2001 bcc:

07:02 Subject: Summary of Conference
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Call on November 13 - Electrical
11/23/2001 Aging Management

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Robert L Gill

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Colaianni/Gen/DukePower@DukePower
cc:

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Rani

From: Rani Franovich
To: Bob Gill
Date: 11/28/01 10:11AM
Subject: Fwd: Discussion points for TLAAs 4.2.1 (USE) and 4.2.2 (PTS) and Draft RAI on AMP B.3.1, Alloy 600 Review

Bob,
Please see the attached note and let me know if you have any questions about what the staff is asking for.
Thanks-
Rani

From: James Medoff
To: Rani Franovich
Date: 11/28/01 10:06AM
Subject: Discussion points for TLAAs 4.2.1 (USE) and 4.2.2 (PTS) and Draft RAI on AMP B.3.1, Alloy 600 Review

Rani:

Here's the file containing my comparison of what Duke submitted in TLAAs for USE (LRA Section 4.2.1 and Tables 4.2-1 through -4) and PTS (LRA Section 4.2.2 and Table 4.2-4 through -8) and what we calculated using the RVID. Forward the file to Duke. We will use the file as basis for a phone call with Duke today or tomorrow to discuss the TLAA data in the application, and to determine exactly what sort of information we need to request in our RAIs on TLAAs 4.2.1 and 4.2.2.

I'm also enclosing the file draft RAIs on AMP B.3.1, Alloy 600 Review. If we send it to the applicant we will then discuss them in a phone conversation and edit them if necessary and formally issue them to the applicant. Note that there are only three very basic global RAIs on AMP B.3.1. Keith just looked at the RAIs and okayed them as drafts.

Note that we have no RAIs on the AMP B.3.9, Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program, as we are going to issue a broad-based Open Item on the AMP that is based on our issuance of Bulletin 2001-01, and having Duke update the AMP to cover their Bulletin response and the latest rankings for their VHP nozzles that were reported in the MRP's generic response to the Bulletin (i.e., as reported in Report MRP-48).

Maybe we can discuss these items (TLAA issues and the RAIs on AMP B.3.1) in one phone. conversation.

Forward these files to Duke so that we can discuss them in a phone conversation.

Thanks,

Jim

CC: Barry Elliot; Clifford Munson; Keith Wichman; Meena Khanna

Comparison of Data Between What RVID
Would Calculate and What Duke Has Reported for
Upper Shelf Energy and PTS at End of Extended Operating Periods
(TLAA Tables 4.2-1 through 4.2-4) (All Fluences in units of E19 n/cm^2)

McGuire Unit 1 - USE

1. Intermediate Shell Plate B5012-1 (Using Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 101 ft-lb ; RVID: 89 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 11% ; RVID: 8.3 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 90 ft-lb ; RVID: 81.6 ft-lb

2. Intermediate Shell Plate B5012-2 (No Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 105 ft-lb ; RVID: 89 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 26% ; RVID: 26 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 78 ft-lb ; RVID: 65.6 ft-lb

3. Intermediate Shell Plate B5012-3 (No Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 112 ft-lb ; RVID: 89 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 23% ; RVID: 23 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 86 ft-lb ; RVID: 77.1 ft-lb

4. Intermediate Shell Plate B5013-1 (No Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 95 ft-lb ; RVID: 84 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 26% ; RVID: 26 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 70 ft-lb ; RVID: 62 ft-lb

5. Intermediate Shell Plate B5013-2 (No Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 115 ft-lb ; RVID: 96 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 22% ; RVID: 22 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 90 ft-lb ; RVID: 75 ft-lb

6. Intermediate Shell Plate B5013-3 (No Surveillance Data):

   Unirradiated USE Value (65%) - Duke: 103 ft-lb ; RVID: 85 ft-lb
   1/4T fluence of 1.83, Projected USE Decrease - Duke: 22% ; RVID: 22 %
   1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 80 ft-lb ; RVID: 66.4 ft-lb

7. Axial Weld Seams 2-442 A, B and C (Using Surveillance Data):

   Unirradiated USE Value (Direct Measurement) - Duke: 112 ft-lb ; RVID: 112 ft-lb
   1/4T fluence of 1.63, Projected USE Decrease - Duke: 36% ; RVID: 44.4 %
   1/4T fluence of 1.63, Projected USE at 54 EFPY - Duke: 72 ft-lb ; RVID: 62 ft-lb
   1/4T fluence of 1.13, Projected USE Decrease - Duke: 33% ; RVID: 40.8 %

1/4T fluence of 1.13, Projected USE at 54 EFPY - Duke: 75 ft-lb ; RVID: 66 ft-lb

8. Axial Weld Seams 3-442 A, B and C (Using Sister Plant Surveillance Data):

Unirradiated USE Value (Sister Plant Data) - Duke: 124 ft-lb ; RVID: 103 ft-lb
1/4T fluence of 1.63, Projected USE Decrease - Duke: 40% ; RVID: 44.4 %
1/4T fluence of 1.63, Projected USE at 54 EFPY - Duke: 74 ft-lb ; RVID: 57.2 ft-lb
1/4T fluence of 1.13, Projected USE Decrease - Duke: 37% ; RVID: 40.8 %
1/4T fluence of 1.13, Projected USE at 54 EFPY - Duke: 78 ft-lb ; RVID: 60.9 ft-lb

9. Girth Weld 9-442 (No Surveillance Data):

Unirradiated USE Value (Direct Measurement) - Duke: 143 ft-lb ; RVID: 126.3 ft-lb
1/4T fluence of 1.83, Projected USE Decrease - Duke: 22% ; RVID: 22%
1/4T fluence of 1.83, Projected USE at 54 EFPY - Duke: 112 ft-lb ; RVID: 98.6 ft-lb

10. USE Data have been given for Nozzle Shell Plates B5453-2, B5011-2, and B5011-3, for Nozzle Shell Longitudinal Weld Seams 1-442 A, B, and C, and for the Nozzle Shell to Intermediate Shell Circumferential Weld Seam. These materials are not listed in the most recent version of the RVID as being beltline materials that need to be evaluated. With respect to these materials:

    A. Have bases for establishing the unirradiated upper shelf energy data and initial RT-ndt data for these materials been placed on the NRC docket? If the data have been placed on the docket please tell us where we may find it. If data are not on the docket, the bases should be submitted to NRC to support your USE and PTS evaluations of the nozzle materials at the end of the extended operating period for McGuire Unit 1.

<u>McGuire Unit 1</u> - PTS Evaluation Data:

1. The Duke and RVID PTS Data for all Intermediate and Lower Shell Plates and for Intermediate to Lower Shell Circumferential Weld correspond to one another.

2. Axial Weld Seams 2-442 A, B and C (Using Surveillance Data Ratio Method):

RT-ndt(u) data - Duke: -50 ; RVID: -50
Margin Term data - Duke: 28; RVID: 28
Chemistry Factor - Duke: 156.5 ; RVID: 150.3
at ID Fluence of 1.89, Delta RT-ndt - Duke: 183.1 ; RVID: 176.5
at ID Fluence of 1.89, RT-pts - Duke: 161 ; RVID: 154.5
at ID Fluence of 2.73, Delta RT-ndt - Duke: 198.8 ; RVID: 190.6
at ID Fluence of 2.73, RT-pts - Duke: 177 ; RVID: 168.6

3. Axial Weld Seams 3-442 A, B and C (Using Sister Plant Surveillance Data Ratio Method):

RT-ndt(u) data - Duke: -50 ; RVID: -50
Margin Term data - Duke: 28; RVID: 28
Chemistry Factor - Duke: 194.4 ; RVID: 209.2
at ID Fluence of 1.89, Delta RT-ndt - Duke: 227.4 ; RVID: 245.6
at ID Fluence of 1.89, RT-pts - Duke: 205 ; RVID: 223.6
at ID Fluence of 2.73, Delta RT-ndt - Duke: 246.9 ; RVID: 265.3
at ID Fluence of 2.73, RT-pts - Duke: 225 ; RVID: 248.3

4. No PTS evaluation data and evaluations have been given for the nozzle shell plates and the nozzle weld materials that correspond to USE evaluations that were performed for them. Provide the corresponding PTS evluations for these materials, including the copper and nickel values for the heats of materials (and bases for establishing them), the ID end-of-extended term fluence values for the materials (and bases for establishing them), the initial RT-ndt(u) values for the materials (and bases for establishing them), whether appropriate material surveillance data exist for the nozzle materials that need to incorporated into the assessment (and if they exist submit the calculations for the chemistry factor determination using the surveillance data), delta-RT-ndt data and margin term data (and bases for calculating them), and the final end-of-extended term RT-pts values for the materials.

McGuire Unit 2 - USE

1. Shell Forging 05 (Using Surveillance Data):

Unirradiated USE Value (Direct Measurement) - Duke: 94 ft-lb ; RVID: 100 ft-lb
1/4T fluence of 1.73, Projected USE Decrease - Duke: 24% ; RVID: 24 %
1/4T fluence of 1.73, Projected USE at 54 EFPY - Duke: 71 ft-lb ; RVID: 76.5 ft-lb

2. Shell Forging 04 (No Surveillance Data):

Unirradiated USE Value (65%) - Duke: 141 ft-lb ; RVID: 97 ft-lb
1/4T fluence of 1.73, Projected USE Decrease - Duke: 28% ; RVID: 27 %
1/4T fluence of 1.73, Projected USE at 54 EFPY - Duke: 102 ft-lb ; RVID: 70.7 ft-lb

3. Intermediate to Lower Forging Circumferential Weld (Using Surveillance Data)

Unirradiated USE Value (Direct Measurement) - Duke: 132 ft-lb ; RVID: 140 ft-lb
1/4T fluence of 1.73, Projected USE Decrease - Duke: 3.5% ; RVID: 3.5 %
1/4T fluence of 1.73, Projected USE at 54 EFPY - Duke: 127 ft-lb ; RVID: 135.4 ft-lb

4. USE Data have been given for Nozzle Forging 06 and the Nozzle Shell to Vessel Shell Weld. These materials are not listed in the most recent version of the RVID as being beltline materials that need to be evaluated. With respect to these materials:

A. Have bases for establishing the unirradiated upper shelf energy data and initial RT-ndt data for these materials been placed on the NRC docket? If the data have been placed on the docket please tell us where we may find it. If data are not on the docket, the bases should be submitted to NRC to support your USE and PTS evaluations of the nozzle materials at the end of the extended operating period for McGuire Unit 2.

<u>McGuire Unit 2</u> - PTS Evaluation Data:

1. PTS Data for Intermediate Forging 05 and for Forging 04 correspond to one another within the degree of rounding off the data values.

2. Intermediate to Lower Forging Circumferential Weld (Using Surveillance Data Ratio Method - Note this material is not the limiting material)

   RT-ndt(u) data - Duke: -68 ; RVID: -68
   Margin Term data - Duke: 28; RVID: 28
   Chemistry Factor - Duke: 39.6 ; RVID: 31.5
   at ID Fluence of 2.88, Delta RT-ndt - Duke: 40.3 ; RVID: 50.7
   at ID Fluence of 2.88, RT-pts - Duke: 0; RVID: 10.7

3. No PTS evaluation data and evaluations have been given for the nozzle forging and the nozzle weld material that correspond to USE evaluations that were performed for them. Provide the corresponding PTS evluations for these materials, including the copper and nickel values for the heats of materials (and bases for establishing them), the ID end-of-extended term fluence values for the materials (and bases for establishing them), the initial RT-ndt(u) values for the materials (and bases for establishing them), whether appropriate material surveillance data exist for the nozzle materials that need to incorporated into the assessment (and if they exist submit the calculations for the chemistry factor determination using the surveillance data), the delta-RT-ndt data and margin term data (and bases for calculating them), and the final end-of-extended term RT-pts values for the materials.

<u>Catawba Unit 1</u> - USE

1. USE data for Forging 04, Forging 05 and the circumferential weld joining them correspond to one another within rounding differences.

2. As before, USE Data have been given for Nozzle Forging 06 and the Nozzle Shell to Vessel Shell Weld. These materials are not listed in the most recent version of the RVID as being beltline materials that need to be evaluated. With respect to these materials:

A. Have bases for establishing the unirradiated upper shelf energy data and initial RT-ndt data for these materials been placed on the NRC docket? If the data have been placed on the docket please tell us where we may find it. If data are not on the docket, the bases should be submitted to NRC to support your USE and PTS evaluations of the nozzle materials at the end of the extended operating period for Catawba Unit 1.

<u>Catawba Unit 1</u> - PTS Evaluation Data

1. PTS Data for Intermediate Forging 05 correspond to one another within the degree of rounding off the data values.

2. Forging 04 (No Surveillance Data)

   RT-ndt(u) data - Duke: -13 ; RVID: -13
   Margin Term data - Duke: 33.8 (1/2 Delta RT-ndt method); RVID: 34 (Position 1.1)
   Chemistry Factor - Duke: 26 ; RVID: 31
   at ID Fluence of 3.12, Delta RT-ndt - Duke: 33.8 ; RVID: 40.8
   at ID Fluence of 3.12, RT-pts - Duke: 55 ; RVID: 61.8

3. Intermediate to Lower Forging Circumferential Weld (Using Surveillance Data Ratio - Note this material may be the limiting material depending where the nozzle material PTS assessments come out)

   RT-ndt(u) data - Duke: -51 ; RVID: -51
   Margin Term data - Duke: 28 ; RVID: 28 (Position 2.1)
   Chemistry Factor - Duke: 23.2 ; RVID: 17
   at ID Fluence of 3.12, Delta RT-ndt - Duke: 30.2 ; RVID: 22.1
   at ID Fluence of 3.12, RT-pts - Duke: 7 ; RVID: -0.9

4. No PTS evaluation data and evaluations have been given for the nozzle forging and the nozzle weld material that correspond to USE evaluations that were performed for them. Provide the corresponding PTS evluations for these materials, including the copper and nickel values for the heats of materials (and bases for establishing them), the ID end-of-extended term fluence values for the materials (and bases for establishing them), the initial RT-ndt(u) values for the materials (and bases for establishing them), whether appropriate material surveillance data exist for the nozzle materials that need to incorporated into the assessment (and if they exist submit the calculations for the chemistry factor determination using the surveillance data), the delta-RT-ndt data and margin term data (and bases for calculating them), and the final end-of-extended term RT-pts values for the materials.

<u>Catawba Unit 2</u> - USE

1. Nit - 1/4T fluence that correspond to an ID fluence of 3.16 in 1.88 not 1.902 (but not much difference here).

2. Other than the nit on the fluence here, USE data for lower and intermediate shell plate materials, axial weld seams, and the intermediate to lower shell weld correspond to one another within degrees of rounding data values.

3. USE Data have been given for Nozzle Shell Plates B5453-2, B5011-2, and B5011-3, for Nozzle Shell Longitudinal Weld Seams 1-442 A, B, and C, and for the Nozzle Shell to Intermediate Shell Circumferential Weld Seam. These materials are not listed in the most recent version of the RVID as being beltline materials that need to be evaluated. With respect to these materials:

   A. Have bases for establishing the unirradiated upper shelf energy data for these materials been placed on the NRC docket? If the data have been placed on the docket please tell us where we may find it. If data are not on the docket, the bases should be submitted to NRC to support your USE and PTS evaluations of the nozzle materials at the end of the extended operating period for Catawba Unit 2.

<u>Catawba Unit 2</u> - PTS Evaluation Data

1. The PTS for the vessel shell plates and welds data correspond within the degree of rounding (including I assume rounding copper and nickel values for the materials up from three significant digits to two).

2. No PTS assessments of the axial shell weld seams needed as they are fabricated from the same heat of material as the circumferential weld for the shells (heat 83648), and will yield at as conservative or less conservative RT-pts values than that for the circumferential weld.

3. No PTS evaluation data and evaluations have been given for the nozzle shell plates and the nozzle weld materials that correspond to USE evaluations that were performed for them. Provide the corresponding PTS evluations for these materials, including the copper and nickel values for the heats of materials (and bases for establishing them), the ID end-of-extended term fluence values for the materials (and bases for establishing them), the initial RT-ndt(u) values for the materials (and bases for establishing them), whether appropriate material surveillance data exist for the nozzle materials that need to incorporated into the assessment (and if they exist submit the calculations for the chemistry factor determination using the surveillance data), delta-RT-ndt data and margin term data (and bases for calculating them), and the final end-of-extended term RT-pts values for the materials.

Note to Duke: According to data submitted in the application for the McGuire and Catawba materials, there appear at this time to be no USE or PTS issues in terms of complying with the regulations. However, some of the USE values for the nozzle material are on the verge of the end of extended life screening criteria for USE (50 ft-lb). Should the Reactor Systems Branch have issues on the 1/4t fluences for these materials and determine that the fluences listed in the application are not conservative, the actual USE values for these materials could projected to be less than 50 ft-lb at the end of the extended operating periods. In this case the rule

(10 CFR Part 50, Appendix G) would then require an equivalent margins analysis for the materials. This is something we definitely need to discuss.

COMPILED RAIs FOR McGUIRE/CATAWBA LRA AMP B.3.1, ALLOY 600 REVIEW

RAI B.3.1-1

Your description of the Alloy 600 Aging Management Review (A600AMR) provided in Section B.3.1 to Appendices B of the applications does not identify those Alloy 600 82/182, or 52/152 components or locations within the scope of the program. Identify all Alloy 600, 82/182, or 52/152 components or locations within the scope of the A600AMR.

RAI B.3.1-2

Your description of the A600AMR does not provide how the review program will satisfy the program attributes defined in Section B.2.2 of Appendix B to the applications. Provide the program attributes, as defined in Section B.2.2 of Appendix B to the applications, for the A600AMR.

RAI B.3.1-2

You have not yet conducted the ranking assessment for the nickel-based alloy components within the scope of the A600AMR. Provide further details of the modeling methods used to rank the susceptibility of the MNS/CNS nickel-based alloy components within the scope of the A600AMR to develop primary water stress corrosion cracking (PWSCC). Upon completion of the ranking assessment, provide the relative PWSCC susceptibility rankings for these components or locations, provide your analysis criteria for deciding whether further/additional inspections are required of these components or locations, and state, for those components for which it is determined that additional inspections are necessary, which of the other AMPs will be used, in conjunction with the A600AMR, to manage PWSCC in these components. Indicate which Alloy 600, 82/182, and 52/152 components, other than the vent nozzle, instrumentation nozzles and CRDM nozzles to the vessel head, will be examined either volumetrically or visually.

From: "Robert L Gill Jr" <rlgill@duke-energy.com>
To: "Rani Franovich" <RLF2@nrc.gov>
Date: 11/28/01 11:23AM
Subject: Re: Conference Call Summary on Sections 2.3.1, 2.3.2.7, 2.3.2.8, and 2.3.3.4

Rani,

Here are Duke comments on the RCS, ESF, and AUX System telecon summary of 11/14/2001:

2.3.1 RCS
1. The lifting lugs are attached to a pressure boundary component. The line item in Table 3.1-1 covers external surfaces the RCS pressure boundary even though the lifting lugs do not perform a PB function during operation.

2. Class 1 NSSS supoort are in row 4 of Table 3,5-3 (page 3.5-18) Also note that pipe supports for other piping is on page 3.5-21, 1st row of the table.

3. RAI #5 the diagram is of similar reactor vessel internals. Line 1 should read: McGuire reactor vessel internals do not have diffuser plates.

2.3.27 RHR
1. Response applicant reponse to read: According to the applicant, the spray nozzle is not relied upon to control RCS pressure during a design basis event.

Bob

"Rani Franovich" <RLF2@nrc.gov>
11/26/2001 04:11 PM

To: <rlgill@duke-energy.com>
cc:
bcc:
Subject: Conference Call Summaries on Fire Protection Program and Sections 2.3.1, 2.3.2.7, 2.3.2.8, and 2.3.3.4

Bob,
Please review the attached conference call summaries and provide comments when you can.
Thanks-
Rani

(See attached file: Conference Call Summary Nov 8 01 - Fire Protection Program RAIs.wpd)(See attached file: Conference Call Summary Nov 14 01 - RCS, RHR, CVCS Scoping.wpd)

CC: "Gregory D Robison" <gdrobiso@duke-energy.com>, "Mary H Hazeltine" <mhhazelt@duke-energy.com>

LICENSEE : Duke Energy Corporation

FACILITIES: McGuire, Units 1 and 2, and Catawba, Units 1 and 2

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON THE FIRE PROTECTION PROGRAM

On November 8, 2001, after the NRC (the staff) reviewed information provided in Appendix B of the license renewal application (LRA), a conference call was conducted between the staff and Duke Energy Corporation (the applicant) to clarify information presented in the application pertaining to Section B.3.12, the Fire Protection Program.

The questions asked by the staff, as well as the responses provided by the applicant, are as follows:

1. The application states in Sections B.3.12.1, "Fire Barrier Inspections," and B.3.12.2, "Mechanical Fire Protection Components" that no preventive actions are taken to prevent aging effects or to mitigate aging degradation. Provide your justification for this course of action in light of the fact that operating experience at Catawba/ McGuire indicates that degradation and wall thinning in piping has been observed to the extent that sections of the piping were replaced due to leakage.

   The applicant indicated that the Fire Protection Program is credited as a condition monitoring program, such that preventive actions are not applicable. The applicant referred the staff to the Standard Review Plan for License Renewal (SRP-LR), page A.1-3, which states that condition monitoring programs do not rely on preventive actions and, this, this information need not be provided. The staff is satisfied with this response and has no additional questions on this issue.

2. The application states in Section B.3.12.2, "Mechanical Fire Protection Component Tests and Inspections-Monitoring and Trending", of the LRA that a sample of sprinklers are either inspected or replaced after 50 years of operation. Describe the basis for the sampling process. Also, provide the rationale for either inspection or replacement of only some of the sprinklers after 50 years of operation.

   The applicant indicated that the UL (Underwriter Laboratories?) listing for the sprinklers is 50 years, and National Fire Protection Association (NFPA) Code 25, Section 2-3.1.1, specifies the sprinkler sampling methodology. The code dictates a sample size (of not fewer than four or one percent) requires diverse systems and environments to be represented. (Bob, I'm not so sure that NFPA-25 also provides the rationale for either inspection or replacement of only some of the sprinklers after 50 years. Can you reiterate anything Doug may have offered during the call? My notes don't help me here. Thanks.) The staff will review the applicable section of NFPA 25 and determine if any additional information is needed to complete its review.

3. With regard to the monitoring and trending activities, fouling of hose station valves and sprinklers are managed by flow tests and flushes which are governed by Selected Licensee Commitment (SLC) 16.9.1(a)(iii) at Catawba and Testing Requirement (TR) 16.9.1.3 at McGuire. What are the differences between these two requirements?

   The applicant indicated that the tests were the same, although the test is required by a SLC at Catawba and by a TR at McGuire. The tests involve a high-velocity flush to remove debris and a flow test, which is compared to hydraulic calculations. The applicant suggested that the staff review both requirements to verify that there are no substantive differences. The staff will review and compare SLC 16.9.1(a)(iii) and TR 16.9.1.3 and will determine if additional information is needed to complete its review of this item.

4. With regard to the monitoring and trending activities, the integrity of the sprinkler branch lines is assured by sprinkler system flow tests which are governed by Selected Licensee Commitment TR 16.9-2(a)(iv)(1) at Catawba. This test is not governed by Selected Licensee Commitment at McGuire, but is performed to satisfy a specific plant procedure. Specify the governing requirements for this test at McGuire and how these requirements differ from those at Catawba, and why.

   The applicant and staff agreed that a request for additional information would be issued to provide the applicant an opportunity to submit an official response.

5. With regard to the monitoring and trending activities, explain the basis for the sample disassembly inspection program for managing the fouling of sprinkler branch lines. Specifically, explain how the sample of branch lines is selected (basis for selection) and how the number of branch lines to be sampled is determined (basis for sample size).

   The applicant and staff agreed that a request for additional information would be issued to provide the applicant an opportunity to submit an official response.

6. The acceptance criteria for visual inspection of sprinklers do not contain any requirements for restraining excessive displacement at damaged or malfunctioning pipe hangers. Such requirements seem to be particularly significant for those piping runs where operating experience indicates that fouling has been detected and sections of piping have been replaced due to pinhole leaks. Indicate whether or not requirements exist to limit excessive displacement of sprinkler piping due to degraded hangers. If they do exist, state those requirements.

   Jai, I propose that we delete this question from the conference call summary because there was a misinterpretation of the information in the LRA that I don't believe is attributable to the quality of their document. I had asked you to spend a few days thinking about this item to be sure you are comfortable with the applicant's intent in describing the acceptance criteria they apply to their visual inspections that go beyond the condition monitoring of fire water system components. They apparently described all of what their procedure does for them, although only some of that procedure is credited for license renewal. You and I reviewed page 2.4-11 (Section 2.4.3), page 3.5-12, and page B.3.21-1 to confirm that pipe supports are addressed by other aging management programs, such that excessive displacement at damaged or malfunctioning pipe hangers would be identified by those credited programs. Can we delete this item from the conference call summary? Or do you think there is value added by retaining it?

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
License Renewal Project Directorate
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Attachment: As stated

cc w/attachment: See next page

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
License Renewal Project Directorate
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Attachment: As stated

cc w/attachment: See next page

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Division of Regulatory Improvement Programs
COVER PAGE

DATE: November 23, 2001

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON THE FIRE PROTECTION PROGRAM

ORIGINATOR: R. Franovich

SECRETARY: S. Chey

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ADAMS ACCESSION NUMBER: **ML** DATE ENTERED: / /01

FORM 665 ATTACHED and filled out: **YES** **NO**

COMMITMENT FORM ATTACHED: **YES** **NO**

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TELECOMMUNICATION PARTICIPANTS
November 8, 2001

Staff Participants

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Jai Rajan

Duke Energy Corporation Participants

Bob Gill

Rounette Nader

Doug Brandes

Attachment

LICENSEE : Duke Energy Corporation

FACILITIES: McGuire, Units 1 and 2, and Catawba, Units 1 and 2

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON SCOPING OF THE REACTOR COOLANT SYSTEM (SECTION 2.3.1), ENGINEERED SAFETY FEATURES (SECTIONS 2.3.2.7 and 2.3.2.8) AND AN AUXILIARY SYSTEM (SECTION 2.3.3.4)

On November 14, 2001, after the staff reviewed information provided in Sections 2.3.1, 2.3.2, and 2.3.3 of the license renewal application (LRA), a conference call was conducted between the NRC and Duke Energy Corporation to clarify information presented in the application pertaining to scoping of certain components in the reactor coolant system (RCS), the residual heat removal (RHR) system, the safety injection (SI) system, and the chemical and volume control system (CVCS).

The questions asked by the staff, as well as the responses provided by the applicant, are as follows:

<u>2.3.1 Reactor Coolant System</u>

1. Borated water leakage through the pressure boundary in 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.

   The applicant indicated that lifting lugs are one of the pressure boundary components referred to generically in Table 3.1-1 and are addressed in the first row of that table (page 3.1-5 or the LRA). The exterior surface of lifting lugs (a pressure boundary component) is subject to loss of material and managed by the Fluid Leak Management Program. The staff is satisfied with this response; however, since the pressure boundary function of lifting lugs is not apparent, the staff may issue a formal request for this information to obtain a written response.

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 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.

The applicant indicated that seismic lugs are addressed in Table 3.1-1 (first row on page 3.1-6). Seismic lugs are reactor vessel and pressurizer integral attachments that perform a support function. The applicant stated that valve support brackets are not used at Catawba or McGuire. Piping supports are used instead, and these components are addressed in Table 3.5-3 (second row on page 3.5-18). (Bob, please confirm that I have the right item here. Thanks.) The staff is satisfied with this response but may issue a formal request to provide the applicant an opportunity to submit a written response pertaining to the design use of piping supports in lieu of valve support brackets. (Muhammad, if you would like a written response for seismic lugs, just let me know and I'll modify the staff's response. Thanks.)

3. Page 5.4-43 of Catawba UFSAR, states that the head cooling spray nozzles are relied upon to cool the reactor vessel upper head at Catawba, and that this is a direct flow path between the downcomer region and the upper head region. In addition, the staff believes that the component performs the function of flow distribution, as reported by other Westinghouse plant applicants. The staff, however, notes that the subject components may not have been identified in the LRA to be within scope requiring aging management. Therefore, the staff requests the applicant to provide a justification as to why the intended safety functions of the component do not require it to be within the scope of license renewal. The staff understands from the past license renewal reviews of Westinghouse plants that such components should be in scope if a plant is designed with such components.

   The applicant indicated that the head cooling spray nozzles are included as part of the core barrel assembly and is addressed in Table 3.1-1 (first row on page 3.1-18). The applicant indicated that the function to provide a passageway for the distribution of the reactor coolant flow to the reactor core is represented by Note 1, Item 3. The staff is satisfied with the information provided in the LRA and has no other questions on this item.

4. Based on past LRA reviews and on the information provided in McGuire and Catawba UFSAR, the staff believes that the flow downcomers (reactor vessel internals) should require aging management because the components provide structural and/or functional support for in-scope equipment. If the applicant believes otherwise, then the staff requests the applicant to provide the justification.

   The applicant indicated that there is no flow downcomer component at Catawba or McGuire, but acknowledged that there is a downcomer(annulus) region between the core barrel and the reactor vessel wall. The staff identified the core barrel (first row on page 3.1-18) and the upper, lower and intermediate reactor vessel shell (pages 3.1-11 thru 3.1-12) in Table 3.1-1 and is satisfied with the information in the LRA. There are no other questions on this item.

5. Section 3.9.1.3, (on page 3.9-4) of the McGuire UFSAR, states that the diffuser plate was relied upon when performing the dynamic system load analyses for reactor internals at McGuire to determine the behavior of lower structures when subjected to loads. Furthermore, based on past license renewal reviews of Westinghoue 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.

   The applicant indicated that McGuire reactors do not have diffuser plates. A generic analysis performed by Westinghouse? demonstrated that this component was not necessary for dynamic load distribution or flow distribution. The applicant referred the staff to WCAP 14577, Revision 1A, page 2-42, to review a diagram of(What is the diagram of, Bob? Thanks.) The staff will consider this information, but may request additional information to confirm that diffuser plates are not installed in the McGuire reactors, since the UFSAR indicates that they are installed and serve a function that appears to be within the scope of license renewal.

6. 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. Based on past LRA reviews and on the information provided in McGuire and Catawba UFSAR, the staff's view is that these components perform the intended safety function of providing structural and/or functional support for in-scope equipment, and therefore, should be within the scope of license renewal requiring aging management: Anti-vibration bars, stay rod, tube bundle wrapper, and tube support plates.

   The applicant indicated that the components in question do not meet the license renewal rule's scoping criteria because they are secondary supports for steam generator tubes and are designed to prevent wear. A failure of these secondary supports would not cause a loss of safety function, but, over time, would result in vibration-induced tube wear. The staff will consider this response; however, the staff notes that the Generic Aging Lessons Learned (GALL) report specifies aging management of tube support lattice bars (page IV D1-10) and tube support plates (page IV D1-12). Although the GALL report's intended function is not to perform scoping reviews, the staff considers items such as the lattice bars and tube support plate to have one universal function. As such, there is no apparent reason why these components would have a function within the scope of license renewal at one plant and outside the scope of license renewal at another plant. For this reason, the staff may request additional information to complete its review.

<u>2.3.2.7 Residual Heat Removal System</u>

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, and/or to shut down the reactor, then the staff requests the applicant to explain why the spray head (the component which actually sprays the water) need not require aging management to prevent clogging of the spray holes, or any other aging related degradation over the extended period of operation.

The applicant indicated that the basis for not including the spray nozzle in the scope of license renewal was because it does not perform a function that meets the scoping criteria. According to the applicant, he spray nozzle is not needed to control RCS pressure as long as a flow path exists to provide cold water to the pressurizer. The staff will consider the information provided, but may request additional information to confirm that a spray pattern is not credited by the applicant for immediate pressure reduction during design basis events.

2.3.2.8 Safety Injection System

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.

   The applicant indicated that vortex suppressors are part of the containment recirculation sump screen assembly, which is listed on page2.4-3 of the LRA. The applicant also referred the staff to UFSAR Figures 6-111 (Catawba) and 6-196 (McGuire) for diagrams of the containment sump assemblies (including vortex supressors). The staff reviewed page 2.4-3 of the LRA and confirmed that containment recirculation sump screen assembly is listed on that page. However, the staff noted that only containment recirculation sump screens are listed in the aging management review (AMR) results tables (specifically, Table 3.5-1 on page 3.5-9). As such, the staff will request additional to completed its review of this item.

2.3.3.4 Chemical and Volume Control System

1. Chemical & Volume Control System (CVCS) flow diagram CN-1554-1.6 indicates that the piping from isolation valve 1NV145 to the inlet of the letdown heat exchanger is categorized as line listing 07 (Duke Class B, ASME Class 2). Portions of this line are highlighted to be within the scope of License Renewal. The staff requests that the applicant explain why a portion of the line including isolation valve 1NV145 to the inlet of the letdown heat exchanger is not within the scope of license renewal.

   The applicant indicated that the referenced piping was within the scope of license renewal and noted that the drawing was in error.

2. Flow diagrams CN-1554-1.6 and CN-2554-1.6 indicate from the CVCS letdown line to and including valve 1NV152 and 2NV152 are line listing 19 (Duke Class B, ASME Class 2). The staff requests that the applicant explain why these portions of the CVCS are not within the scope of license renewal.

   The applicant indicated that the referenced piping was within the scope of license renewal and noted that the drawing was in error.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
License Renewal Project Directorate
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Attachment: As stated

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3. Flow diagrams CN-1554-1.6 and CN-2554-1.6 indicate from the CVCS letdown line to and including valve 1NV152 and 2NV152 are line listing 19 (Duke Class B, ASME Class 2). The staff requests that the applicant explain why these portions of the CVCS are not within the scope of license renewal.

   The applicant indicated that the referenced piping was within the scope of license renewal and noted that the drawing was in error.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

Rani L. Franovich, Project Manager
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Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

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Division of Regulatory Improvement Programs
COVER PAGE

DATE: November 13, 2001

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON SCOPING OF THE REACTOR COOLANT SYSTEM (SECTION 2.3.1), ENGINEERED SAFETY FEATURES (SECTIONS 2.3.2.7 and 2.3.2.8) AND AUXILIARY SYSTEMS (SECTION 2.3.3.4)

ORIGINATOR: R. Franovich

SECRETARY: S. Chey

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ADAMS ACCESSION NUMBER: **ML** DATE ENTERED: / /01

<u>FORM 665</u> ATTACHED and filled out: **YES** **NO**

<u>COMMITMENT FORM</u> ATTACHED: **YES** **NO**

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NOVEMBER 14, 2001

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Attachment

From: "Robert L Gill Jr" <rlgill@duke-energy.com>
To: "Rani Franovich" <RLF2@nrc.gov>
Date: 11/28/01 3:25PM
Subject: Re: Fwd: Discussion points for TLAAs 4.2.1 (USE) and 4.2.2 (PTS) and DraftRAI on AMP B.3.1, Alloy 600 Review

Rani,

You may want to get a copy of Catawba LER 414/01-002 dated 11/12/2001 which concerns RCS PB leakage due to small cracks found in SG Channel Head Bowl Drain line on 2B SG. Its an Alloy 600 component.

From: Rani Franovich
To: Bob Gill
Date: 11/28/01 4:44PM
Subject: Summary of October 25 conference call - Mechanical AMPs

0Bob,
The summary is attached. As always, comments are welcome.
Thanks-
Rani

LICENSEE : Duke Energy Corporation

FACILITIES: McGuire, Units 1 and 2, and Catawba, Units 1 and 2

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON AGING MANAGEMENT PROGRAMS FOR MECHANICAL SYSTEMS AND COMPONENTS

On October 25, 2001, after the NRC (the staff) reviewed information provided in Appendix B of the license renewal application (LRA), a conference call was conducted between the staff and Duke Energy Corporation (the applicant) to clarify information presented in the application pertaining to aging management programs for mechanical systems and components. Participants in the conference call are provided in an attachment.

The questions asked by the staff, as well as the responses provided by the applicant, are as follows:

<u>B.3.4 Borated Water Systems Stainless Steel Inspection</u>

1. The LRA proposes that one of twelve possible inspection locations at each plant will be inspected volumetrically as part of the Borated Water Systems Stainless Steel Inspection program (monitoring & trending). Stainless steel (SS) has demonstrated susceptibility to intergranular stress corrosion cracking (IGSCC) in low-temperature borated water systems in pressurized water reactors, particularly in stagnant lines, at weld heat-affected zones (HAZs), involving weld procedures that resulted in sensitization of the stainless steel in the HAZs. Since IGSCC has a wide range of induction and propagation rates, depending on degree of sensitization, local stresses, and specific impurities at a given location, justify why only a one-time inspection is sufficient. Also, since not all welds, stress patterns, and impurity levels and species are necessarily similar, justify why inspection of only one of twelve locations adequately represents the durability of material at the other eleven locations and explain the process for inspection population expansion should aging effects be identified.

    The applicant indicated that the containment spray piping is essentially the same (material and environment) at each plant (or unit?? Bob, can you answer?), such that one spray pipe is representative of all twelve. As such, if no parameters are known that would distinguish certain locations at each site as being more susceptible to loss of material or cracking, one location will be chosen based upon radiological conditions and accessibility. The applicant also indicated that the staff previously found this aging management program acceptable, as documented in the safety evaluation report for the staff's review of the Oconee LRA. The staff will consider the information provided in the applicant's response, but may request additional information to complete its review of this item.

2. The LRA proposes that a one-time inspection be performed and that no actions are to be taken to trend inspection results (monitoring & trending). The LRA also states that if an engineering evaluation determines that the aging effects, identified during the one-time inspection, will not result in a loss of the component's intended function(s) during the period of extended operation, then no further action will be required. Industry operating experience has shown that, under this environment, stress-corrosion cracking tends to result in leaks that are somewhat localized. In this light, explain the basis for not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending).

   The applicant indicated that engineering judgment would be applied to determine if corrective actions are warranted based upon the results of the one-time inspection. Provisions for programmatic oversight would be established at the time the results of the inspection are obtained, and the inspection results, as well as corrective actions taken by the applicant (licensee), would be subject to NRC inspection at the appropriate time in the future. The staff will consider this information but may request additional information to determine the appropriateness of not performing future inspections at those locations in which aging effects have been identified in order to ensure that degradation predictions made in the engineering evaluations remain valid (detection of aging effects and monitoring & trending). In addition, the staff may request that the applicant describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

3. The LRA states that the parameters inspected by the borated water systems stainless steel inspection program are pipe wall thickness, as a measure of loss of material, and evidence of cracking (parameters monitored or inspected). Will the inspections also be looking for evidence of pitting? If so, discuss the inspection technique(s) that will be used to reliably identify the presence of pits (monitoring & trending).

   The applicant indicated that the volumetric technique (ultrasonic testing) would reveal loss of material from pitting. The staff is satisfied with this response but may request this information formally.

<u>B.3.14 Flow Accelerated Corrosion Program</u>

1. The LRA states that the inspection frequency for each location will vary and depend on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experience (monitoring and trending). Identify the predictive model(s) that will be used to predict component degradation in the systems conducive to flow accelerated corrosion and the inspection schedules necessary to provide reasonable assurance that the structural integrity will be maintained between inspections. Also discuss how these models have been benchmarked.

The applicant indicated that the predictive model to be used is CHECWORKs, and that the inspection schedules would be determined in accordance with EPRI document NSAC-202L based upon inspection results and wear rate, as documented in the LRA under Section B.3.14, Flow Accelerated Corrosion Program. The staff is satisfied with this response and has no additional questions on this issue.

2. Describe the basis for location sampling and the provisions for expanding the inspection scope (i.e., additional examinations) in the event that degradation is detected that exceeds the acceptance criteria (monitoring and trending).

   The applicant indicated that the basis for location sampling and the provisions for expanding the inspection scope is provided in the EPRI document, which is referenced in the Flow-Accelerated Corrosion program documented on page XI M-58 of the Generic Aging Lessons Learned (GALL) report. The staff is satisfied with this response and has no additional questions on this issue.

B.3.15 Fluid Leak Management

1. The program is stated to focus on carbon and low alloy steels (scope). There are several cases of failure of stainless steels in borated water systems, for example, spent fuel pool piping. Why is stainless steel not indicated as a relevant material?

   The applicant indicated that boric acid corrosion of stainless steel is not a plausible aging effect. The staff is satisfied with this answer and has no additional questions on this issue.

2. There is no mention of strategies that address leak management for component segments that are not accessible to visual inspection (monitoring and trending). Indicate whether there are provisions in the fluid leak management program for leak management in inaccessible locations.

   The applicant indicated that the condition of material in accessible areas is considered indicative of material in inaccessible areas. The staff will consider this information, but may request additional information to understand the applicant's response to Generic Letter 88-05, which may contain provisions for inspecting potentially vulnerable locations for boric acid corrosion.

B.3.16 Galvanic Susceptibility Inspection

1. The LRA states that the galvanic susceptibility inspection will inspect a select set of carbon steel-stainless steel couples at each site (monitoring and trending). Since the galvanic susceptibility inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed, explain how the sample size will be selected in order to ensure that the inspection population is representative for all systems listed in the galvanic susceptibility inspection program scope.

The applicant indicated that a bounding approach will be used for the one-time inspection such that the worst-case combination of materials and environments will be inspected. Material and environment combinations that are less susceptible to galvanic corrosion will be inspected if the worst-case combinations reveal degradation. The staff will consider this information, but may request additional information to complete its review of this item.

2. In the LRA, provisions for sample size expansion and subsequent inspections, in the event that the initial inspection detects degradation, are not included (monitoring and trending). Provide justification for their exclusion. Otherwise, discuss the criteria that will be used and the procedure that will be implemented for expanding the sample size when degradation is detected in initial/subsequent inspections.

   The applicant indicated that the provisions for sample size expansion and subsequent inspections, in the event that the initial inspection detects degradation, are included in the discussion of corrective actions and confirmation process associated with the Galvanic Susceptibility Inspection. The staff is satisfied with this response and has no additional questions on this issue.

3. The LRA describes the acceptance criterion for the galvanic susceptibility inspections as "no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria that will be used to define "unacceptable loss of material" and how the acceptance criteria will ensure that the component functions are maintained under all CLB design loading conditions during the period of extended operation. Also, describe the analysis methodology that will be used to evaluate the inspection results against the acceptance criteria.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider the information provided in the applicant's response, but may request additional information to complete its review of this item.

4. The LRA states that "programmatic oversight" will be defined in the event that engineering evaluations determine that continuation of the aging effects could cause a loss of component intended function(s) under current licensing basis design conditions for the period of extended operation (corrective action and confirmation). Explain what programmatic oversights will need to be defined in order to implement corrective actions. Clarify if these activities are related to the corrective actions program described in B.3.2.2 of the LRA.

   The applicant indicated that the programmatic oversight will be defined at an appropriate time in the future when the results of the inspection can be considered to develop that oversight. The applicant also indicated that the corrective action process would be used to document the inspection results as well as the planned and completed actions (including programmatic oversight) taken to correct the degradation. The staff is satisfied with this response and has no additional questions on this issue.

5. The scope of the galvanic susceptibility inspection program is indicated to include all galvanic couples exposed to gas, unmonitored treated water, and raw water environments in the McGuire and Catawba systems listed (scope). However, the proposed implementation involves only measurements on carbon steel-stainless steel couples (parameters monitored or inspected), based on an assumption that this couple represents a worst case, based on expectations from the galvanic series (monitoring and trending). First, note that the relative position in the series can shift, depending on specific environments. Second, note that the position of stainless steel in the series depends on whether the material is active or passive. Third, as an example, copper alloys are listed as relevant materials. Could the CS/SS couple measurements provide favorable results that fail to address the galvanic phenomena that may be degrading other materials?

   The list of systems includes nuclear service water, which is large, complex, usually with multiple materials, subject to a variety of environments, that may change over time, including flowing and stagnant water, microbiological species, etc. The mechanisms include localized (e.g., pitting) and uniform corrosion. Given these complexities, justify that limiting the proposed inspections to carbon-stainless steel couples provides sufficient evidence in regards to the potential aging degradation of all galvanic couples in nuclear service water and other systems.

   The applicant indicated that raw water is the worst case, bounding environment for galvanic corrosion. The staff will consider this information, but may request additional information to complete its review of this item as well as Question 1 under B.3.16, Galvanic Susceptibility Inspection. Any future request for additional information on this issue will address both of these questions, if appropriate.

6. The LRA states that the parameter inspected by the galvanic susceptibility inspection program is pipe wall thickness (parameters monitored or inspected) and inspections will be performed using a volumetric examination technique. As an alternative, visual examination will be used should access to internal surfaces become available (monitoring and trending). Is it the intent to substitute the volumetric examination (wall thickness) with a visual examination for those components where access to the internal surfaces is available? If so, describe how section thickness will be determined.

   The applicant indicated that their intent was not to substitute a volumetric test with a visual inspection. The applicant acknowledged that a visual inspection does not provide the same level of confidence that a volumetric examination provides. The staff is satisfied with this response. However, since the LRA states that a visual inspection could be used as an alternative to volumetric testing, the staff will request this clarification formally from the applicant.

B.3.17 Heat Exchanger Activities

1. The approaches for heat exchanger performance testing at Catawba and McGuire involve flow monitoring using differential pressure tests (parameters monitored and inspected). Do the tests include converting mass flow to linear flow velocity to assure that flow regimes that promote flow-assisted corrosion are avoided? This is particularly important in systems involving admiralty brass, which has shown susceptibility to flow-induced corrosion in heat exchangers in power systems.

   The applicant requested the staff to review the aging management review tables to determine if any heat exchanger materials involve admiralty brass. The applicant also requested the staff to share with them the operating experience that indicates that admiralty brass, and any other material, is susceptible to flow-induced corrosion in heat exchangers so they can review the information for applicability to Catawba and McGuire. The staff will take these requests under consideration and incorporate specific references to industry operating experience into any future request for additional information on this issue.

2. The pressure differential test, while an indicator of fouling, does not directly address assurance of satisfactory heat transfer coefficients. It seems possible that relatively thin films may have poor heat transfer characteristics. Describe the monitoring and trending method or technique that will be used to ensure that the heat exchangers are capable of adequate heat transfer required to meet system and accident load demands.

   The applicant requested the staff to share with them the operating experience that involves the phenomenon of thin films that have poor heat transfer characteristics so they can review the information for applicability to Catawba and McGuire. The staff will either provide industry operating experience to the applicant for their review and determination of applicability, or the staff will reconsider its need for additional information to complete its review of this item.

3. The LRA states that the performance testing will monitor flow capacity by measuring the pressure drop through the component cooling heat exchanger tubes to identify the presence of fouling (parameters monitored or inspected). Will the monitoring and testing program for the component cooling heat exchangers also consider performance parameters on the shell side? If so, explain what parameters will be monitored. Describe how the parameters being monitored will indicate degraded heat transfer capabilities.

   The applicant indicated that treated water flows through the component cooling water heat exchanger shell and requested the staff to indicate if, perhaps, this question applies to other heat exchangers for which raw water flows through the shell. The staff will identify heat exchangers that are exposed (shell-side) to raw water and will review LRA Section B.3.29, Service Water Piping Corrosion Program, to verify that aging management of the heat exchanger interior shell is addressed.

B.3.22 Liquid Waste System Inspection (EMEB/Jain)

1. In section B.3.22 of the LRA, under monitoring & trending, the applicant stated that the selection of the specific areas for inspection for the system material/environment combinations will be the responsibility of the system engineer. Discuss the selection criteria that will be used by the system engineer for the inspection of the specific areas.

   The applicant suggested that the staff issue a request for additional information so that they can provide the selection criteria to the staff in their response.

2. The acceptance criterion for the liquid waste system inspection program is "no unacceptable loss of material and cracking of stainless steel components and loss of material of carbon steel and cast iron components that could result in a loss of the component intended function(s) as determined by engineering evaluation." Describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider this information, but may request additional information to complete its review of this issue.

B.3.32 Sump Pump Inspection (EMEB/Rajan)

1. The acceptance criterion for the sump pump inspection program is "no unacceptable loss of material that could result in the loss of the component intended function(s), as determined by engineering evaluation." Describe the criteria for (1) assessing the severity of the observed degradation, and (2) determining whether or not corrective action is necessary.

   The applicant indicated that the criteria are not defined for this one-time inspection and that engineering judgment will be applied. The applicant also indicated that it is difficult to establish prescriptive acceptance criteria that will take into account all factors that should be considered in light of the inspection results to determine if a loss of intended function could result. In addition, since the inspection may not reveal any degradation, prescribing acceptance criteria would not be necessary. The staff will consider this information, but may request additional information to complete its review of this issue.

A draft of this telecommunication summary was provided to the applicant to allow them the opportunity to comment prior to the summary being issued.

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Office of Nuclear Reactor Regulation

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

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Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

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

Attachment: As stated

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Division of Regulatory Improvement Programs
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DATE: November 14, 2001

SUBJECT: TELECOMMUNICATION WITH DUKE ENERGY CORPORATION TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON AGING MANAGEMENT PROGRAMS FOR MECHANICAL SYSTEMS AND COMPONENTS

ORIGINATOR: R. Franovich

SECRETARY: S. Chey

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ADAMS ACCESSION NUMBER: **ML** DATE ENTERED: / /01

<u>FORM 665</u> ATTACHED and filled out: **YES** **NO**

<u>COMMITMENT FORM</u> ATTACHED: **YES** **NO**

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OCTOBER 25, 2001

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Attachment

From: Rani Franovich
To: Bob Gill
Date: 11/29/01 10:05AM
Subject: Fwd: RAIs for McGuire/Catawba on Water Chemistry program

Bob,
Thses RAIs were generated very early in the staff's review and, somehow, slipped through the cracks.
Please take a look and let me know if a conference call might be helpful to the reviewer.
Thanks-
Rani

CC: Krzysztof Parczewski

From: Krzysztof Parczewski
To: Meena Khanna
Date: 8/9/01 11:38AM
Subject: RAIs for McGuire/Catawba

Attached are my RAIs which are due 8/13/01.

Kris

Request for Additional Information
McGuire and Catawba Plants

Section B.3.6

B.3.6-1 In the chemistry control program the applicant specified four chemistry environments for aging effects controlled by the program: borated water, closed cooling water, treated water, and fuel oil. However, in Tables 3.1-1 through 3.4-9 of the LRA, specifying aging management review results, no distinction is made between the components exposed to treated water and1az\q2 closed cooling water. The applicant should specify the difference between these two chemistry environments and explain why these differences were not recognized in the LRA.

B.3.6-2 In the description of the chemistry control program in the LRA two aging effects were specified: loss of material and cracking. However, in addition to these two effects, water chemistry environment could cause fouling of the heat transfer surfaces in heat exchangers. Tables 3.1-1 through 3.4-1 of the LRA show that this could occur in the following heat exchangers:

Component Cooling System:
- heat exchanger KC
- heat exchanger NS pump motor cooler
- heat exchanger NV centrifugal charging pump bearing oil cooler
- heat exchanger NI pump bearing oil cooler

Control Area Chilled Water System:
- control room area chiller (evaporator tubes)

Control Area Ventilation System:
- air handling units heat exchangers

Diesel Generator Cooling Water:
- D/G engine cooling water heat exchanger
- D/G engine cooling water turbocharger intercoolers
- D/G engine jacket water coolers

Spent Fuel Cooling System:
- heat exchangers

Waste Gas System:
- hydrogen recombiner heat exchangers
-

The applicant should explain why fouling of the heat transfer surfaces in the above listed heat exchangers are not classified as an aging effect managed by the chemistry control program.

B.3.6-3 In the LRA the applicant stated that the chemistry control program is controlled by the site program manuals which are based on the guidance contained in several sources including the EPRI chemistry guidelines. The applicant should specify to what extend the procedures in the site program manuals deviate from the EPRI guidelines for secondary water chemistry.

B.3.6-4 The applicant should specify the acceptance criteria for fuel oil and specify the standards used in developing these acceptance criteria.

B.3.6-5 The applicant should specify the typical parameters monitored for each of the four chemistries specified in the LRA.

B.3.6-6 Does the applicant plan to verify effectiveness of the chemistry control program by performing a one-time inspection of the selected components and the susceptible locations in the systems exposed to the water or fuel oil environments? This type verification could be accomplished by reviewing repair records to confirm that no significant degradation has occurred.

File: McGuire&Catawba-RAI-Chemistry Control.wpd