December 13, 2001

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 November 5, 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. This conference call resumed discussions of staff questions that had been initiated on October 25, 2001. The questions discussed on that date are documented in a separate conference call summary. Participants in the November 5, 2001, 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.3.17 Heat Exchanger Activities</u>

(Questions 1, 2 and 3 were discussed on October 25, 2001, and are documented in the associated telephone conference summary).

4. The LRA states that a periodic differential pressure test will be performed on the Catawba component cooling heat exchanger (monitoring and trending). Discuss how the frequency of testing is established at Catawba and justify that this frequency will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands.

   The applicant indicated that periodic differential pressure testing was established to monitor service water problems affecting safety-related equipment, documented in Generic Letter 89-13. The test is performed quarterly and, in the 12 years since this test was implemented at Catawba, there has been no significant change in differential pressure readings that would warrant more frequent testing. The applicant indicated that if tests began to reveal degraded heat transfer capability, corrective actions (which might include increasing the test frequency) would be taken to address the adverse condition. The staff is satisfied with the response regarding test frequency, but may request additional information to provide the applicant an opportunity to include this information in a written response.

5. The LRA states that at McGuire, the performance testing activities for the diesel generator engine cooling water heat exchangers involve monitoring of flow capacity by performance of a differential pressure test to provide an indication of fouling

(parameters monitored or inspected). Since it seems possible that relatively thin films may have poor heat transfer characteristics, discuss how the raw water side differential pressure monitoring will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands. Describe how this parameter will be indicative of degraded heat transfer capabilities (monitoring and trending).

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 applicant further explained that the diesel generator engine cooling water heat exchangers have a differential temperature of about 5°F, and that the instrumentation is not sufficiently accurate in that range to provide a reliable indication of heat transfer across the heat exchanger. 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.

6. The LRA states that the performance testing activities for the diesel generator engine cooling water heat exchangers at McGuire and Catawba will be performed every six months (monitoring and trending). At McGuire, the performance testing involves the measurement of a differential pressure across the raw water side of the heat exchangers every six months. At Catawba, the performance testing involves a heat capacity test that computes a tube side fouling factor using tube and shell side inlet and outlet temperatures and flows every six months. Describe the basis for the testing frequency and justify that this frequency will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands.

   The applicant indicated that these heat exchangers are in service only while the emergency diesel engine is operating. When the heat exchangers are in service they experience high flow rates. The applicant believed that the flow tests may have been performed quarterly at some time, but that the frequency was reduced because the results of the tests did not reveal significant degradation and did not warrant the associated cost. The staff is satisfied with this response and has no additional questions on this issue.

<u>B.3.18 Ice Condenser Inspections</u>

1. The acceptance criterion for the ice condenser inspections program is "no unacceptable visual indication of loss of material of the ice baskets that would prevent the ice condenser from performing its intended function." Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

   The applicant referred the staff to Table 18-1 of the Catawba and McGuire updated final safety analysis report (UFSAR) Supplements, which provided references to Section 18.2.14 (for McGuire) and Section 18.2.13 (for Catawba) for additional details on the inspection program. Table 18-1 of the McGuire and Catawba UFSAR Supplements also provided references to Improved Technical Specification (ITS) 3.6.12 (for both plants). The staff reviewed the ITS, including surveillance requirements, and

determined that these references provided adequate acceptance criteria. The staff is satisfied with the information provided in the LRA and in the ITS and has no additional questions on this issue.

B.3.24 Preventive Maintenance Activities

1. The LRA describes the scope of the Condenser Circulating Water System Internal Coating Inspection activities and states that the inspection is applicable to several systems (diesel generator fuel oil, exterior fire protection, interior fire protection, nuclear service water system and standby shutdown system) in addition to the intake and discharge piping of the condenser circulating water system. The various elements of the aging management program (parameters monitored or inspected, monitoring and trending, acceptance criteria and operating experience) address only the condenser piping with no reference to the other systems that are within the stated scope of the preventative maintenance activities. Describe how the aging management program is implemented for these other systems, which may consist of smaller diameter piping. Describe operating experience for these systems and the experience to date in application of the preventative maintenance activities to these systems.

   The applicant indicated that the condenser circulating water system internal piping inspection is credited for determining two things: (1) the condition of the condenser circulating water system pipe internal surface coating, and (2) the condition of the condenser circulating water system (and other systems listed under the scope of the program) external surface coating. The condition of the internal surface of this piping is used to indicate (indirectly) the condition of the coating on the external pipe surface. The condition of the condenser circulating water system external pipe surface coating is representative of the external surface coating of piping from other systems governed by this aging management program. The external surface of all piping referenced in the Scope discussion is coated and wrapped in the same manner as the condenser circulating water system piping. The staff will consider this information, but may request additional information to complete its review of this issue.

2. Inspection of the internal coating on underground piping is the principal method to detect corrosion occurring from the soil side (monitoring & trending). Corrosion will be detected only after corrosion from the outside diameter surface has penetrated through the pipe wall coating. A small indication of coating degradation may represent the penetration of a local pit or it may represent the first evidence of more widespread pipe degradation. Comment on whether coating repair operations include a specific requirement to explore the extent of pipe degradation surrounding indications of coating defects.

   The applicant indicated that the corrective action program would be implemented to evaluate indications of coating degradation. The corrective action program would ensure that the extent of the condition is evaluated and appropriate corrective actions are identified to address the root cause. The staff reviewed page B.3.24-3 of the LRA, which states (under the Corrective Action & Confirmation Process element) that engineering evaluation is performed to determine whether the coating and base metal continue to be acceptable, and specific corrective actions and confirmation are

implemented in accordance with the corrective action program. The staff is satisfied with the information provided in the LRA and has no additional questions on this issue.

3. Raw water carries with it sediments and debris that deposit on the bottom of the pipes. If areas of the pipe are obscured by sediments and debris, the coating inspection activities would be compromised (monitoring and trending). Are areas of the pipes obscured by deposits? If so, are special measures applied to facilitate the coating inspection?

   The applicant indicated that the sediment and debris is not typically found in this piping because the continuous flow of raw water removes it from the pipe. However, if sediment or debris were to be found in the piping, the pipe would be cleaned before coating inspection activities would be performed. The staff is satisfied with this response but may request additional information to provide the applicant with an opportunity to submit this information in their written response.

4. The acceptance criteria for the preventive maintenance activities are "no visual indications of coating defects including but not limited to blistering, peeling, or missing coatings that reveal corrosion of the piping as determined by Engineering." Describe the criteria for (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

   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.

<u>B.3.25 Reactor Coolant System Operational Leakage Monitoring Program</u>

1. The LRA credits the reactor coolant operational leakage monitoring program (e.g., containment sump level monitoring and periodic water inventory balances) as managing the aging effect of cracking with a program scope that includes the Inconel penetrations of the reactor pressure vessel head (monitoring and trending). Recent industry experience includes cracking of head penetration welds that resulted in minor leakage from full penetration cracks that were detected only by visual detection of boric acid crystals on the outer head surface. In this case, there was no indication of leakage from the plant's operational leakage monitoring. Explain how the proposed leakage monitoring program will be considered effective and given credit for detecting cracking of head penetration welds as well as other short and/or tight cracks such as pipe weld cracks in Inconel buttering (e.g., V.C. Summer incident).

   The applicant indicated that other aging management programs (e.g., B.3.9, the Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program) are credited with managing cracking of reactor pressure vessel head Inconel penetrations. The applicant referred the staff to Table 3.1-1, which contains the aging management review results for control rod drive mechanism housings (located on page 3.1-13 of the LRA), to illustrate the number and variety of programs credited for managing the aging of this item. The staff is satisfied with the information in the LRA and has no other questions on this issue.

<u>B.3.28 Selective Leaching Inspection</u>

1. The LRA states that Duke will perform Brinnell hardness testing on the inside wetted surfaces of cast iron pump casings and brass valve bodies (parameters monitored or inspected) to detect the presence and extent of material loss due to selective leaching. Since selective leaching generally does not cause changes in dimensions and material loss detection may be difficult, discuss how material loss due to selective leaching in cast iron pump casings and brass valve bodies will be inspected and how the inspection method results relate to the material loss for the applicable selective leaching mechanisms (i.e., dezincification and graphitization).

   The applicant indicated that they have confidence that the Brinnell hardness test will reveal material loss due to selective leaching of system components exposed to raw water environments. The applicant referred the staff to the Generic Aging Lessons Learned (GALL) report. Section XI.M33, which describes the Selective Leaching of Materials program attributes and states (under Detection of Aging Effects) that an acceptable procedure is to visually inspect the susceptible components closely and conduct Brinnell hardness testing on the inside surfaces of the selected set of components to determine if selective leaching has occurred. The applicant also referred the staff to the Oconee LRA Safety Evaluation Report (SER), NUREG-1723, which documents (on pages 3-50 thru 3-52) the staff's acceptance of this program for the renewal of the Oconee units' operating licenses. The staff is satisfied with this response and had no additional questions on this issue.

2. The LRA states that a Brinnell hardness test or an equivalent test will be performed on one cast iron pump casing in the exterior fire protection system at each site and that this test will be indicative of selective leaching for all cast iron components in all the systems listed in the selective leaching inspection program scope (monitoring and trending). Provide the basis for the proposed inspection population and sample size. Discuss, in detail, the system attributes considered in the selective leaching susceptibility analyses and evaluations performed by Duke for the cast iron components in each of the systems listed in the selective leaching inspection program scope. Discuss how the results of these analyses and evaluations were used to support the conclusion that the inspection of a single pump casing in the exterior fire protection system at each site will be indicative of the state of selective leaching in all cast iron components in all raw water systems.

   The applicant indicated that, since the population of components and materials susceptible to selective leaching is subject to change as a result of station modifications, these parameters will be defined at the time of the test to ensure that the sample size is appropriately defined at that time. The applicant stated that there are no evaluations or analyses associated with this aging management program and reiterated the following information in their LRA: for the exterior fire protection system at each site, the test is most easily performed on a pump casing and will be indicative of all cast iron components in the systems in the scope of the program (this also is stated in the LRA under the Monitoring and Trending attribute). The staff will consider this information, but may request additional information to confirm that the pumps selected for testing are reasonably representative of their respective populations.

3. The LRA states that Brinnell hardness tests or equivalent tests will be performed on a sample of brass valves at each site in the interior fire protection system and that these

valves selected for inspection should be (interpreted to mean will be) those that are continuously exposed to stagnant or low flow raw water environments. The LRA also states that the results of this inspection will be applied to the brass components exposed to raw water environments in the remaining systems listed in the selected leaching program scope (monitoring and trending). Describe the analyses or evaluations that will be used to determine the sample size. Discuss, in detail, the system attributes considered in the selective leaching susceptibility analyses and evaluations performed by Duke for the brass components in each of the systems listed in the selective leaching inspection program scope. Discuss how the results of these analyses and evaluations were used to support the conclusion that limiting inspections to brass valve bodies in the interior fire protection system will be indicative of the state of selective leaching in all brass components in all raw water systems.

The applicant indicated that, since the population of components and materials susceptible to selective leaching is subject to change as a result of station modifications, these parameters will be defined at the time of the test to ensure that the sample size is appropriately defined at that time. The applicant stated that there are no evaluations or analyses associated with this aging management program and reiterated the following information in their LRA: for the interior fire protection system, the test will be performed on a sample of brass valves at each site that are continuously exposed to stagnant or low flow raw water environments. The staff will consider this information, but may request additional information to confirm that the valves selected for testing are reasonably representative of their respective populations.

4. 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 information pertaining to sample size, expansion and subsequent inspections in the event that the initial inspection detects degradation is provided under the Corrective Action & Confirmation Process attribute. It states that, if engineering evaluation determines that additional information is required to more fully characterize any or all of the aging effects, then additional inspections will be completed or other actions taken to obtain the additional information. The staff is satisfied with the information provided in the LRA and has no additional questions on this issue.

5. The LRA describes the acceptance criterion for the selective leaching 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 current licensing basis (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 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 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). Please 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 nature of the programmatic oversight would be contingent upon the nature and severity of the aging effects. As such, programmatic oversight would be defined in response to the specific aging issue(s). Programmatic oversight does not need to be defined to implement corrective actions; in fact, the corrective action program would be used to define the age-related problem, identify the root cause, establish an owner of the programmatic oversight, and specify corrective actions. The staff is satisfied with this response and has no additional question on this issue.

<u>B.3.29 Service Water Piping Corrosion Program</u>

1. The LRA describes the parameters monitored or inspected as part of the service water piping corrosion program to be wall thickness measurements as an indicator of loss of material (monitoring & trending). What methods (e.g., codes/standards or industry guidelines) are used to select the ultrasonic test procedures and the number/grid of locations to be inspected?

   The applicant indicated that the locations for inspection would be determined based upon flow regime and geometry. High-stress locations would be designated for testing, and cross-sections of flow regimes (high, intermediate and low) and stagnant conditions would be represented. The staff will consider this information, but may request additional information to complete its review of this issue.

2. The LRA describes the scope of the service water piping corrosion program and states that it is applicable to several systems (nuclear service water, containment spray, diesel generator cooling water, etc.). The description of operating experience in the LRA makes only a general statement of typical corrosion rates, which range from 3 to 5 mills per year. Provide examples for corrosion rates for specific systems, and examples of how measurements have been used to determine frequencies of re-inspection and to expand the number of locations for wall thickness measurements.

   The applicant and staff agreed that a request for additional information would be issued to provide the applicant an opportunity to submit information pertaining to operating experience and programmatic provisions for determining frequencies of re-inspection and expanding the number of locations for wall thickness measurements.

<u>B.3.34 Treated Water Systems Stainless Steel Inspection</u>

1. The LRA states that because of the higher starting level of contaminants in the Catawba drinking water system, cracking or loss of material is more likely to occur in that system

than in the containment valve injection water or solid radwaste systems. Therefore, the inspection results from the Catawba drinking water system are proposed to be bounding (monitoring & trending). Three factors have been identified that promote stress corrosion cracking (SCC) of stainless steels: (1) metallurgical (e.g., sensitization), (2) stress level, and (3) environmental (e.g., level of contaminants). The basis for the proposed Catawba treated water systems stainless steel inspection program only focuses on one of these three factors, namely environment. Discuss how the metallurgical and stress level factors were considered in the system susceptibility comparisons performed by Duke or, justify why these factors were not considered.

The applicant indicated that this aging management program is credited for condition monitoring. The applicant assumes that factors necessary to cause SCC (metallurgy, stress level and environment) are present for mechanical components within the scope of this aging management program. The applicant limited the scope of the program to stainless steel components exposed to unmonitored treated water environments that promote SCC. The staff is satisfied with this response and has no additional questions on this issue.

2. The LRA describes the acceptance criterion for the treated water systems stainless steel inspection program as no unacceptable loss of material that could result in a loss of the component intended function(s) as determined by engineering evaluation (acceptance criteria). 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 referred the staff to the applicable section of the Oconee SER on pages 3-61 thru 3-64 for a discussion of the staff’s assessment of the Oconee LRA’s acceptance criterion (also “unacceptable loss of material” and potential loss of component function). The staff reviewed the Oconee SER and concluded that the staff had made reference to specific minimum design wall thickness and maximum crack and flaw size. Therefore, the staff will issue a request for additional information to provide the applicant an opportunity to submit an official response.

3. 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 & confirmation). Please explain what programmatic oversights will be needed to be defined in order to implement corrective actions. Clarify if these activities are related to the corrective action programs described in B.3.2.2 of the LRA.

   The applicant indicated that the nature of the programmatic oversight would be contingent upon the nature and severity of the aging effects. As such, programmatic oversight would be defined in response to the specific aging issue(s). Programmatic oversight does not need to be defined to implement corrective actions; in fact, the corrective action program would be used to define the age-related problem, identify the root cause, establish an owner of the programmatic oversight, and specify corrective actions. The staff is satisfied with this response and has no additional questions on 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.

/***RA***

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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3. 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 & confirmation). Please explain what programmatic oversights will be needed to be defined in order to implement corrective actions. Clarify if these activities are related to the corrective action programs described in B.3.2.2 of the LRA.

   The applicant indicated that the nature of the programmatic oversight would be contingent upon the nature and severity of the aging effects. As such, programmatic oversight would be defined in response to the specific aging issue(s). Programmatic oversight does not need to be defined to implement corrective actions; in fact, the corrective action program would be used to define the age-related problem, identify the root cause, establish an owner of the programmatic oversight, and specify corrective actions. The staff is satisfied with this response and has no additional questions on this issue.

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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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S. Droggitis
N. Dudley
RLSB Staff

R. Martin
C. Patel
C. Julian (RII)
R. Haag (RII)
A. Fernandez (OGC)
J. Wilson
M. Khanna
C. Munson
R. Elliott
B. Rogers

Mr. Gary Gilbert
Regulatory Compliance Manager
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745

Ms. Lisa F. Vaughn
Duke Energy Corporation
422 South Church Street
Charlotte, North Carolina 28201-1006

Anne Cottington, Esquire
Winston and Strawn
1400 L Street, NW
Washington, DC 20005

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

County Manager of York County
York County Courthouse
York, South Carolina 29745

Piedmont Municipal Power Agency
121 Village Drive
Greer, South Carolina 29651

Ms. Karen E. Long
Assistant Attorney General
North Carolina Department of Justice
P. O. Box 629
Raleigh, North Carolina 27602

Ms. Elaine Wathen, Lead REP Planner
Division of Emergency Management
116 West Jones Street
Raleigh, North Carolina 27603-1335

Mr. Robert L. Gill, Jr.
Duke Energy Corporation
Mail Stop EC-12R
P. O. Box 1006
Charlotte, North Carolina 28201-1006

Mr. Alan Nelson
Nuclear Energy Institute
1776 I Street, N.W., Suite 400
Washington, DC 20006-3708

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

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
4830 Concord Road
York, South Carolina 29745

Mr. Virgil R. Autry, Director
Dept of Health and Envir Control
2600 Bull Street
Columbia, South Carolina 29201-1708

Mr. C. Jeffrey Thomas
Manager - Nuclear Regulatory Licensing
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28201-1006

Mr. L. A. Keller
Duke Energy Corporation
526 South Church Street
Charlotte, North Carolina 28201-1006

Saluda River Electric
P. O. Box 929
Laurens, South Carolina 29360

Mr. Peter R. Harden, IV
VP-Customer Relations and Sales
Westinghouse Electric Company
5929 Carnegie Blvd.
Suite 500
Charlotte, North Carolina 28209

Mr. T. Richard Puryear
Owners Group (NCEMC)
Duke Energy Corporation
4800 Concord Road
York, South Carolina 29745

Mr. Richard M. Fry, Director
North Carolina Dept of Env, Health, and
Natural Resources
3825 Barrett Drive
Raleigh, North Carolina 27609-7721

County Manager of
Mecklenburg County
720 East Fourth Street
Charlotte, North Carolina 28202

Michael T. Cash
Regulatory Compliance Manager

Duke Energy Corporation
McGuire Nuclear Site
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Senior Resident Inspector
U.S. Nuclear Regulatory Commission
12700 Hagers Ferry Road
Huntersville, North Carolina 28078

Dr. John M. Barry
Mecklenburg County
Department of Environmental Protection
700 N. Tryon Street
Charlotte, North Carolina 28202

Mr. Gregory D. Robison
Duke Energy Corporation
Mail Stop EC-12R
526 S. Church Street
Charlotte, NC 28201-1006

TELECOMMUNICATION PARTICIPANTS
November 5, 2001

Staff Participants

Rani Franovich

Clifford Munson

Meena Khanna

Duke Energy Corporation Participants

Greg Robison

Bob Gill

Rounette Nader

Mike Semmler

Attachment