June 22, 2000

LICENSEES: Entergy Operations, Inc. (Entergy)

FACILITIES: Arkansas Nuclear One, Unit 1 (ANO-1)

SUBJECT: SUMMARY OF JUNE 6 AND 7, 2000, TELECOMMUNICATION WITH ENTERGY REGARDING AUXILIARY SYSTEMS FOR ANO-1

On June 6 and June 7, 2000, the U.S. Nuclear Regulatory Commission (NRC) staff had a conference call with representatives of Entergy, to discuss technical questions relating to information on the Auxiliary Systems provided in the license renewal application (LRA). Enclosure 1 provides the Auxiliary System requests for additional information (RAIs) discussed during the conference call, the applicant's response to the discussions, and the disposition of each RAI based on the applicant's response.

A draft of this phone conversation summary was provided to Entergy to allow them the opportunity to comment prior to the summary being issued.

/***RA***/

Robert J. Prato, Project Manager
License Renewal and Standardization Branch
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos. 50-313 (Entergy)

Enclosure: Meeting Summary

cc w/ encl: See next page

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AUXILIARY SYSTEMS

3.3.4.3.1 AGING EFFECTS

3.3.4.3.1-7 Please verify that all references to SAR refer to the UFSAR?

In the LRA application Section 1.3, first paragraph on page 1-5, the application states that references to SAR throughout the application refers to the FSAR. The applicant verified that this is the same as the term UFSAR for ANO-1.

3.3.4.3.1.1 Spent Fuel

3.3.4.3.1.1-2 The LRA contains a statement that if chlorides are present in external concrete of a component that contains a stainless steel liner plate (such as the spent fuel pool), cracking of the stainless steel liner is an applicable aging effect. Please identify where in Appendix C to the LRA, is the process used to identify cracking of the stainless steel liner plate due to exposure to chlorides in external concrete.

Appendix C basically addresses non Class 1 components (some Class 1 components were evaluated under Appendix C) and was intended to provide additional information on how the applicant determined aging effects from the environment and material conditions existing in the plant. The applicant did look at the spent fuel pool liner plate in Appendix C but did not consider concrete as an environment in any of the “tools” used to determine aging from environment and materials. However, the applicant identified cracking from chlorides contained in concrete as a potential aging effect during the operating history review, and included it based on industry operating experience.

3.3.4.3.1.2 Fire Protection

3.3.4.3.1.2-1 Appendix C, Section 4.3.3, of the LRA, contains a statement that fouling applies to a raw water system. Table 3.4-2 of the LRA does not consider fouling as an applicable aging effect and other aging effects as a result of fouling, such as MIC, as applicable aging effects for (except for heat exchangers) the fire protection system components exposed to raw water. Identify where in the LRA are fouling and other related aging effects addressed for the Fire Protection Systems, or provide a technical justification for exclusion of these aging effects.

The applicant stated that they only considered fouling an aging effect associated with the potential loss of heat transfer function, and not associated with the potential loss of pressure boundary function. The staff agrees with this assessment.

3.3.4.3.5 Alternate AC Diesel Generator

3.3.4.3.1.5-2 Are there any low-allow steel components in the AAC diesel generator system? If so, state the environments in which they reside, and the aging effects considered for these materials and environments. Identify where in the LRA are the AMR for these components and the applicable aging effects, or provide a technical justification for each aging effect considered and determined not to require an AMR.

As indicated in Appendix C, page C-7, of the LRA, carbon steel and low alloy steel are used synonymously in the application because they experience the same aging effects under similar conditions.

3.3.4.3.1.7 Fuel Oil

3.3.4.3.1.7-2 Appendix C, Section 6.3.1 of the LRA identifies stress corrosion cracking as an applicable aging effect for stainless steel components when exposed to oxygenated water. Table 3.4-7 does not identify oxygenated water as an applicable environment for the Fuel Oil System heat exchanger. Please verify that the tube side or shell side of the stainless steel heat exchanger is not exposed to raw water and or oxygenated water. If exposed to raw water or oxygenated water, perform an AMR for stress corrosion cracking for this component.

The heat exchanger in question is the SBO DG heat exchanger and is a radiator type heat exchanger that uses air to cool the medium inside the tubes. Therefore, this heat exchanger has an air and oil environment and is not exposed to a raw or oxygenated water environment.

3.3.4.3.1.7-3 Appendix C, Section 6.3.1 of the LRA, identified cracking for stainless steel components exposed to fuel oil. Verify that the tube side or shell side of the stainless steel heat exchanger is not exposed to fuel oil, if so perform an AMR for cracking for this component.

The staff discussed this RAI with the applicant and as a result, revised it to read as follows: "Appendix C, Section 6.3.1 of the LRA, identified cracking for stainless steel components exposed to fuel oil. Identify whether or not the tube side or shell side of the stainless steel heat exchanger is exposed to fuel oil. If so, perform an AMR for cracking for this component." This question will be included in the staff's request for additional information (RAI).

3.3.4.3.1.7-4 Loss of material for the exterior surface of the fuel oil system components made of carbon steel, admiralty, brass, cast iron, and copper is managed by protective coatings applied to these surfaces. In the past, the staff has typically accepted coatings as an applicable aging management program. However, because the coating can be damaged or worn, applicants have been required to manage the aging of coating surfaces. Identify where in the LRA is the AMP for coating that are applicable to the fuel oil systems components made of carbon steel, admiralty, brass, cast iron, and copper. Provide an AMR, AMP, and a demonstration for the coating credited for managing aging associated with these components.
As described in Appendix B, page 73, the applicant informed the staff that the Maintenance Rule Program is used to manage coatings for carbon steel. The applicant stated that components that are admiralty, brass, and copper are inherently corrosion resistant (i.e., loss of material does not occur at a rate sufficient to require aging management) in an external ambient environment.

Therefore, the intended function would be maintained during the period of extended operation without reliance on an aging management program. However, Table 3.7-4 incorrectly listed cast iron as not requiring aging management. The applicant stated that cast iron does rely on coatings to manage aging and therefore is subject to the Maintenance Rule Program. The applicant will correct this error in the table, and submit it with other corrections requested.

3.3.4.3.1.7-5 Please clarify that the reference to gas-air for heat exchanger environment in Table 3.4-7 is referring to coolant side of the heat exchanger supplied by raw water, and that “raw water” would be a better description of the environment.

The heat exchanger referenced in this RAI is the SBO DG radiator heat exchanger discussed above, 3.3.4.3.1.7-3 and is not exposed to raw water.

3.3.4.3.1.12 Auxiliary Building Heating and Ventilation

3.3.4.3.1.12-1 In our review of the Auxiliary Building Heating and Ventilation, in general, the staff assumed that the pressure boundary function applied to the tube, tube sheet and shell of the heat exchanger, and the heat transfer function applied only to the heat exchanger tubes.

In addition, the staff also assumed that aging caused by the raw water environment of the Service Water System for all the Auxiliary System (such as the tube side [end bell, tube sheet, and interior of the tubes] of many of the Auxiliary Systems heat exchangers) is addressed under Table 3.4-10, “Service Water System.” The only other tables that addresses the potential aging associated with raw water is Table 3.4-4, “Auxiliary Building Sump and Reactor Building Drain System,” and Table 3.4-2, “Fire Protection System,” because of the multiple environments, including raw water, that share the same piping and components.

Please state whether this assumption is correct or incorrect, if incorrect, please provide clarification.

The applicant verified that this assumption is correct.

3.3.4.3.1.12-2 The reference to fouling for the Decay Heat Removal and the switchgear room coolers in Table 3.4-12 refers to the loss of heat transfer. The heat transfer function and fouling are not indicated for the Makeup Pump Room coolers. However, Section 9.7.2.1 of the ANO-1 UFSAR states that the internal surface of copper and 90/10 copper-nickel tubing in the decay heat room and makeup pump room coolers is exposed to service water (raw water). Please include heat transfer as an intended function of the Makeup Pump Room coolers, fouling as an applicable aging effect for the Makeup Pump Room coolers and identify an AMP and provide a demonstration, as applicable. If not provide a technical justification for excluding heat transfer or fouling as an intended function or an applicable aging effect, respectively

In response to this question the applicant stated that the heat transfer function is not credited for any of the functions under 10 CFR 54.4(a) and therefore the heat transfer function for these components is not within the scope of license renewal (see paragraph on makeup pump rooms in SAR section 9.7.2.1 on page 9.7-3).

In addition, Table 3.4-12, copper and 90/10 copper-nickel materials for heat exchanger/coolers, identifies gas-air as the environment (assumably for the external surface of the tubing) and fouling as the applicable aging effect. Please verify that the fouling occurs on the tube side of the coolers that are exposed to the service water environment and not on the shell side (ouside of the tubes) of the coolers, which is exposed to a gas-air environment

The applicant verified that this assumption is correct.

3.3.4.3.1.12-2 In evaluating the Auxiliary Building Heating and Ventilation System, the staff assumed that fouling occurs on the tube side of each of the heat exchangers, which is supplied by the raw water. The shell side of these heat exchangers are exposed to chilled water. Is this assumption valid?

The applicant verified that this assumption is correct.

3.3.4.3.1.12-3 For make up pump room coolers, you identified pressure boundary integrity as an intended function for 90/10 copper-nickel tubing, but not the heat transfer capacity. Provide a technical justification for not including heat transfer as an applicable intended function for the Make up Pump Room Coolers. In evaluating the auxiliary building heating and ventilation system, the staff has assumed that heat transfer is the intended function of this tubing. Is this assumption valid?

In response to this question the applicant stated that the heat transfer function is not credited for any of the functions under 10 CFR 54.4(a) and therefore the heat transfer function for these components are not within the scope of license renewal (see paragraph on makeup pump rooms in SAR section 9.7.2.1 on page 9.7-3).

3.3.4.3.1.12-4 Why was fouling not identified as an aging effect for the Make up Pump Room Coolers, which is, according to Section 9.7.2.1 of the ANO-1 SAR, exposed to service water (raw water)? In Section 4.0 of Appendix C to the LRA, you do state that fouling applies to 90-10 copper-nickel heat exchanger tubing exposed to raw water.

In response to this question the applicant stated that the heat transfer function is not credited for any of the functions under 10 CFR 54.4(a) and therefore the heat transfer function and the potential for fouling is not within the scope of license renewal (see paragraph on makeup pump rooms in SAR section 9.7.2.1 on page 9.7-3).

3.3.4.3.1.12-5 Section 9.7.2.1 of the ANO-1 SAR states that the internal surface of copper and 90/10 copper-nickel tubing in the decay heat room and makeup pump room coolers is exposed to service water (raw water). The staff concurs that copper and 90/10 copper-nickel tubing exposed to raw water may corrode and pit, as stated in Section 4.0 of Appendix C to the LRA. But in Table 3.4-12 of the LRA, you have not listed loss of material for the internal surface of the tubing exposed to raw water. Explain this discrepancy.

Reference the response to 3.3.4.3.1.12-1, the aging effects caused by raw water are addressed in Table 3.4-10 for these coolers.

3.3.4.3.1.12-1 Section 9.7.2.1 of the ANO-1 SAR, contains a statement that the internal surface of the copper tubing of the switchgear room coolers is exposed to chilled water (treated water). Appendix C,Section 3.0, contains a statement that the copper tubing may corrode and pit in a water environment. (Please note that aging occurs in a water environment and that water is treated to manage/prevent the aging. Applicants cannot take credit for an AMP such as chemistry control to exclude an aging effect from an AMR). However, Table 3.4-12 of the LRA, does not listed loss of material as an applicable aging effect for the internal surface of the tubing exposed to chilled water. Identify where in the LRA is aging of the switchgear room coolers copper tubing addressed or provide a technical justification for excluding loss of material as an applicable aging effect for these components.

The staff discussed this RAI with the applicant and verified that they took credit for the treated environment of the Chilled Water System for excluding loss of material as an applicable aging effect that needs aging management. The applicant recognized that they took credit for an aging management program to determine an aging effect is not applicable and will provide an appropriate response to the RAI. This question will be included in the staff's RAIs.

3.3.4.3.1.13 Control Room Ventilation System

3.3.4.3.1.13-1 Table 3.4-13 of the LRA, does not identify any aging effects for the evaporator "external-ambient". Provide a technical justification for excluding loss of material as an applicable aging effect for carbon steel under external ambient conditions.

In response to this RAI, the applicant stated that they looked at all carbon steel components, and determined that exterior surfaces of carbon steel components that are located in a "non harsh indoor environment" (not exposed to excessive mositure or humidity) were not subject to loss of material with the exception of cooling water system components that could form condensation on the exterior surfaces. AMP were identified for cooling water systems components that could potentially experience loss of material. The staff determined this to be a reasonable determination.

3.3.4.3.1.13-2 Table 3.4-13 implies that the 90/10 copper-nickel condenser tubing is exposed to lube oil. Section 6.2 of Appendix C to the LRA, does not identify 90/10 copper-nickel as a material found in a lube oil environment. Evaluate potential aging effects for 90/10 copper-nickel tubing in a lube oil environment. Identify the aging effects considered and provide a justification for those determined to be not applicable. For those aging effects determined to be applicable, provide an AMR and a demonstration that the AMP selected will effectively manage the effects of aging consistent with the CLB for the period of extended operation.

In response to this RAI the applicant stated that the copper-nickel tubing in question is exposed to Freon and service water because the condenser is cooled by the service water system. We verified that this tubing was addressed in Table 3.4-10.

3.3.4.3.2 AGING MANAGEMENT PROGRAMS

3.3.4.3.2-8 The requests listed below result from the evaluation of the Reactor Building Leak Rate Testing Program and apply to components in the following systems:

- Spent Fuel System
- Fire Protection System
- Auxiliary Building Sump and Reactor Building Drain
- Chilled Water

Respond to each of the following requests, addressing each system specifically.

a. Reactor Building Leak Rate Testing Program is not credited with managing the "loss of mechanical closure integrity" in Appendix B, Section 4.16 of the LRA. However, Tables 3.4-1 and 3.4-4 of the LRA credit this program for managing mechanical closure integrity for several components. Correct Appendix B, Section 4.16. If Section 4.16 is correct, clarify that each of the AMPs applies to each of the aging effects in the same row on each of the tables in Section 3 of the LRA. If not, specify which program addresses which aging effect throughout all the tables in Section 3.

The staff discussed this specific issue and the potential generic concern if each of the AMPs in each row does not apply to each of the aging effects in the same row. The applicant verified that the intent was to make each AMP apply to each aging effect unless there was some indication (excessive spacing) to indicate otherwise. The applicant verified that each of the AMPs apply to each of the aging effects in this RAI, however, as we continued through our review we identified an error at the bottom of Table 3.4-2. Therefore, this question will be rewritten as follows:

Verify that each AMP in each of the rows apply to each of the aging effects in the same row unless indicated by excessive spaces and alignment of aging effects with AMPs throughout the tables in Section 3 of the LRA. Reference last row in Table 3.4-2. This question will be included in the staff's RAIs.

b. Section 4.16 states that the Reactor Building Leak Rate Testing Program consists of Type A, Type B, and Type C testing. It also states that for the purpose of the AMP for license renewal, only Type A and Type C tests are considered applicable. However, a discussion in Section 4.16.2 also refers to Type B testing for the purpose of license renewal. Clarify the scope of the Reactor Building Leak Rate Testing program as it applies to the auxiliary system piping, pumps, and valves listed in Tables 3.4-2, 3.4-4 and 3.4-9 of the LRA.

The applicant informed the staff, that the Type B test referenced in Appendix B, 4.16.2, only apply to testing of doors and hatches, structural components, not to the Auxiliary Systems.

3.3.4.3.2 Fire Protection

3.3.4.3.2-4b Please state whether any chemical sampling or corrosion coupons are specified in the Service Water Chemical Control program for raw water in the fire protection system. Include locations and frequency of samples taken, and analysis methods used for monitoring and trending of this data.

As discussed in Appendix B, Section 4.6.5, Service Water Chemical Control, under operating experience, corrosion coupons are used throughout the Service Water System. Location and frequency is addressed under another RAI.

3.3.4.3.2-5 Table 3.4-2 of the LRA lists Oil Analysis as an aging management program for fouling in diesel fire pump subsystem heat exchanger(s). The environments listed are treated water for the in-side of tubing and lube oil for the exterior of tubing. Please clarify whether the oil analysis program is applicable to fouling from in treated water.

The applicant stated that Table 3.4-2 is wrong, the Oil Analysis Program is not used to manage fouling in the diesel fire pump heat exchanger. This concern is addressed in RAI 3.3.4.3.2-8a above, regarding verification of tables.