September 18, 2012

ULNRC-05910

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

10 CFR 2.101
10 CFR 2.109(b)
10 CFR 50.4
10 CFR 50.30
10 CFR 51.53(c)
10 CFR 54

Ladies and Gentlemen:

DOCKET NUMBER 50-483
CALLAWAY PLANT UNIT 1
UNION ELECTRIC CO.
FACILITY OPERATING LICENSE NPF-30
SUPPLEMENTAL RESPONSES TO RAI SET #3 TO THE CALLAWAY LRA

References: 1) ULNRC-05830 dated December 15, 2011
2) ULNRC-05886 dated August 6, 2012

By the Reference 1 letter, Union Electric Company (Ameren Missouri) submitted a license renewal application (LRA) for Callaway Plant Unit 1. Reference 2 transmitted responses to the third Request for Additional Information (RAI) related to our application.

Enclosure 1 to this letter contains supplemental responses to the following individual RAIs addressed in Reference 2:

- B2.1.9-7
- B2.1.9-8
- 3.0.1-1

There are no changes to commitments contained in this letter.

If you have any questions with regard to these RAI response supplements, please contact me at (573) 823-9286 or Ms. Sarah Kovaleski at (314) 225-1134.

I declare under penalty of perjury that the foregoing is true and correct.

Sincerely,

Executed on: September 18, 2012

Les H. Kanuckel

Les H. Kanuckel
Manager, Engineering Design

DS/SGK/nls

Enclosure: 1) Supplemental Responses to Request for Additional Information (RAI) Set #3

cc: U.S. Nuclear Regulatory Commission (Original)
Attn: Document Control Desk
Washington, DC 20555-0001

Mr. Elmo E. Collins
Regional Administrator
U. S. Nuclear Regulatory Commission
Region IV
1600 East Lamar Boulevard
Arlington, TX 76011-4511

Senior Resident Inspector
Callaway Resident Office
U.S. Nuclear Regulatory Commission
8201 NRC Road
Steedman, MO 65077

Mr. Samuel Cuadrado De Jesús
Project Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Mail Stop O-11F1
Washington, DC 20555

Mr. Fred Lyon
Senior Project Manager, Callaway Plant
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Mail Stop O-8G14
Washington, DC 20555-2738

Mr. Gregory A. Pick
U. S. Nuclear Regulatory Commission
Region IV
1600 East Lamar Boulevard
Arlington, TX 76011-4511

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Missouri Public Service Commission
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CALLAWAY PLANT UNIT 1
LICENSE RENEWAL APPLICATION

SUPPLEMENTAL RESPONSES TO REQUEST FOR ADDITIONAL INFORMATION (RAI) Set #3

RAI B2.1.9-7

AREVA NP Inc, Document No. 51-9172264-000, "Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21" does not appear to justify the length of the operating interval for secondary side degradation. Section 10.3 of the EPRI Steam Generator Integrity Assessment Guidelines indicates that the operational assessment shall include a justification for operating the planned interval between secondary side inspections as well as primary side inspections. Please discuss whether there is a justification for the planned operating interval that addresses degradation of secondary side internals.

Callaway Response

The first paragraph of Section 10 of document 51-9172264-00 identifies the forms of degradation detected in the Callaway Unit-1 replacement steam generators at the 1R18 outage. These mechanisms were AVB and TSP wear. There was no degradation associated with the secondary side findings (inner bundle or steam drum). The intent of the operational assessment was to address currently detected and/ or previously detected degradation mechanisms located on both the primary and secondary sides of the Steam Generators (SGs). Since the secondary side findings revealed no degradation, discussion was limited to the condition monitoring results located in Section 6.2 of the document.

Section 6.2 of document 51-9172264-00 identifies the Secondary side activities performed at 1R18. These activities included steam drum inspections in SGB and SGC, foreign object and PLP inspections in all four SGs, and sludge lancing in all four SGs. The steam drum inspections revealed no loose parts or loose hardware detected in the steam drum of either SG. The only anomaly noted was two buckles on one of the sectors associated with the loose part trapping screens. This condition was pre-existing and not new. The foreign object and PLP inspections revealed no PLPs or foreign object degradation detected in any SG based on eddy-current inspections. The FOSAR inspections (post-lancing) detected only a small piece of scale in the cold-leg of SGA. The sludge lancing results revealed that only minimal amounts of sludge were contained within each of the four SGs.

The findings at 1R18 echoed the findings at 1R15 (with exception of the single small piece of scale detected in the cold leg of SGA). Based on two consecutive outages of exceptional secondary side inspection results, any projected secondary side degradation is expected to be minimal and to not compromise tube integrity for the planned operating interval.

The Callaway Steam Generator Surveillance procedure is being updated to explicitly state the requirement for the Condition Monitoring Report to include projection data to justify operation for the planned interval between secondary side inspections. This includes degradation of secondary side internals.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI B2.1.9-8

Section 8.6 of the EPRI Steam Generator Integrity Assessment Guidelines indicates, in part, that (1) failure to meet condition monitoring requirements means that the projections of the previous operational assessment were not conservative and that necessary corrective actions shall be identified and (2) even if condition monitoring requirements are met, a comparison of condition monitoring results with the projections of the previous operational assessment shall be performed and that this comparison shall be completed prior to issuance of the final operational assessment since adjustment of input parameters may be required.

In AREVA NP Inc, Document No. 51-9172264-000, "Callaway Unit-1 SG [Steam Generator] Condition Monitoring for Cycles 16, 17, and 18 and Final Operational Assessment for Cycles 19, 20, and 21" there is a statement that the latter must be performed, but then the report went on to indicate that the assumptions and uncertainties included in the previous operational assessment are validated since none of the detected indications approach the condition monitoring limit and that additional discussions below provide further details. The staff could not locate these additional discussions. In addition, in reviewing the previous operational assessment, the staff could not locate any specific projections such that a comparison of the as-found and previously projected conditions could be compared. It is not clear that the intent of the EPRI requirement has been met. Please clarify. The staff notes that the operational assessment is supposed to be conservative. As a result, even if the actual detected conditions are near (including "slightly" below) the projections from the prior operational assessment, this could indicate a potential non-conservative assessment which may lead to issues in the future if not corrected.

Callaway Response

Additional Discussions of Structural Integrity and Leakage Integrity:

The additional discussions, although not specifically referenced, are located in Section 7.2 (Structural Results) and Section 7.3 (Leakage Results) of document 51-9172264-000.

> Section 7.2 discusses how structural integrity was met at 1R18. Also discussed is justification for use of the Axial Partial Through-wall Degradation < 135° model. Condition monitoring curves (Figures 7-1 and 7-2) illustrate structural integrity being met for AVB wear and TSP wear respectively. Even for the bounding case of flat wear profiles, notwithstanding the fact that most profiles had rounded corners, structural integrity was still satisfied. Note also that each indication's percent through-wall (%TW) was small enough such that condition monitoring could be treated as length independent, for all practical purposes.
>
> Section 7.3 discusses how leakage integrity was met at 1R18. Since wear indications leak and break at essentially the same differential pressure, leakage integrity at the lower faulted differential pressure of 3648 psid (resulting from a feedwater line break * 1.4) was satisfied since structural integrity, at the more limiting $3\Delta P$ of 4200 psid, was also demonstrated.

Projections of Previous Operational Assessments:

Section 5.0 (Operational Assessment) of this report implicitly projects EOC18 %TWs by the addition of growth to the return to service %TW population. Both the growth rates and the calculated repair limits are defined in Table 5-1 of document 51-9048595-000. The repair limit corresponds to the largest BOC16 %TW that could sustain the generator specific %TW growth and still satisfy EOC18 structural integrity. For example, using the values shown in Table 5-1 for (all SGs), the projected upper 95th percentile (at 50% confidence) growth rate is 8.5 %TW/ EFPY. The actual observed 95/50 growth rate at EOC18 (all SGs) was 5.5 %TW/ EFPY. Returning to service the maximum %TW detected at 1R15 (14 %TW) and applying the 8.5 %TW/ EFPY growth rate over three cycles (4.2 EFPY) projects the EOC18 maximum percent through-wall to be 50 %TW, without consideration for NDE uncertainty. The largest NDE %TW actually detected at EOC18 was 39 %TW.

In both cases, the implied projections of the 1R15 OA (growth rates and EOC %TW) were satisfied with adequate margin, at EOC18, as demonstrated by the condition monitoring results.

The Callaway Steam Generator Surveillance procedure is being updated to explicitly state the requirement for the Condition Monitoring Report to include a definitive comparison between the current condition monitoring results with the projections of the previous operational assessment.

Corresponding Amendment Changes

No changes to the License Renewal Application (LRA) are needed as a result of this response.

RAI 3.0.1-1

Background:

GALL Report Section IX.D states that stainless steels are susceptible to SCC when exposed to water environments with temperatures above 60°C (140°F). LRA Table 3.0-1 states that its water environments encompass the GALL Report defined environments both above and below the SCC threshold. For example, the closed cycle cooling water environment in the LRA encompasses the GALL Report defined environments of closed cycle cooling water and closed cycle cooling water >60°C (>140°F). Also, the secondary water environment in the LRA encompasses the GALL Report defined environments of treated water and treated water >60°C (>140°F).

Issue:

It is unclear to the staff which components in the LRA may be exposed to water temperatures greater than the SCC threshold. Without this information, the staff cannot evaluate whether SCC is being properly managed.

Request:

Identify which in-scope components are exposed to water environments with temperatures greater than the SCC threshold (60°C, 140°F). For any identified items currently evaluated in the LRA for SCC, add an AMR item to manage this aging effect.

Callaway Response

Stainless steel components exposed to water environments greater than 60°C (140°F) have an aging effect of cracking. The stainless steel components with a water environment and an aging effect of cracking are identified in LRA tables 3.X.2. The following is a list of systems which have stainless steel components exposed to a water environment greater than 60°C (140°F) and the LRA table showing the aging effect of cracking.

Reactor Vessel and Internals (BBVI)	LRA Table 3.1.2-1
Reactor Coolant System (BB)	LRA Table 3.1.2-2
Pressurizer (PZR)	LRA Table 3.1.2-3
Steam Generators (SGR)	LRA Table 3.1.2-4
High Pressure Coolant Injection System (EM)	LRA Table 3.2.2-5
Residual Heat Removal System (EJ)	LRA Table 3.2.2-6
Fuel Storage and Handling System (KE)	LRA Table 3.3.2-1
Fuel Pool Cooling and Cleanup System (EC)	LRA Table 3.3.2-2
Nuclear Sampling System (SJ)	LRA Table 3.3.2-9
Chemical and Volume Control System (BG)	LRA Table 3.3.2-10
Standby Diesel Generator Engine System (KJ)	LRA Table 3.3.2-22
Liquid Radwaste System (HB)	LRA Table 3.3.2-24
Plant Heating System (GA)	LRA Table 3.3.2-28
Boron Recycle System (HE)	LRA Table 3.3.2-28
Main Steam Supply System (AB)	LRA Table 3.4.2-2
Main Feedwater System (AE)	LRA Table 3.4.2-3
Steam Generator Blowdown System (BM)	LRA Table 3.4.2-4

LRA Table 3.3.2-22 has been revised to add AMR lines for the stainless steel components in the standby diesel generator engine system which are susceptible to stress corrosion cracking as shown on LRA Amendment 5 in Enclosure 2.

Corresponding Amendment Changes

Refer to the Enclosure 2 Summary Table "LRA Changes from RAI Responses", for a description of LRA changes with this response.