UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

March 6, 2014

Mr. D. W. Rencurrel
Chief Nuclear Officer
STP Nuclear Operating Company
P.O. Box 289
Wadsworth, TX 77483

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE SOUTH TEXAS PROJECT, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – SET 27 (TAC NOS. ME4936 AND ME4937)

Dear Mr. Rencurrel:

By letter dated October 25, 2010, STP Nuclear Operating Company submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew operating licenses NPF-76 and NPF-80 for South Texas Project, Units 1 and 2, for review by the U.S. Nuclear Regulatory Commission (NRC)staff. The NRC staff is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information have been presented to Mr. Arden Aldridge of your staff, and we request your response within 90 days of the date of this letter. If you have any questions, please contact me by telephone at 301-415-3873 or by e-mail at john.daily@nrc.gov.

Sincerely,

John W. Daily, Sr. Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-498 and 50-499

Enclosure:
As stated

cc w/encl: Listserv

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ADAMS Accession No. ML14050A172 *concurrence via email

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SOUTH TEXAS PROJECT, UNITS 1 AND 2
REQUEST FOR ADDITIONAL INFORMATION - SET 27
(TAC NOS. ME4936 AND ME4937)

RAI A.1-3, License Renewal Commitments and the UFSAR

Background:

By letter dated October 25, 2010, STP Nuclear Operating Company (STPNOC or the applicant) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, to renew operating licenses NPF-76 and NPF-80 for South Texas Project, Units 1 and 2, for review by the U.S. Nuclear Regulatory Commission (NRC) staff.

The staff of NRC is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." By letter dated February 15, 2013, the NRC provided the "Safety Evaluation Report with Open Items Related to the License Renewal of South Texas Project, Units 1 and 2" (SER), and requested that STPNOC review the SER and provide comments to the NRC staff. During the review of the STPNOC license renewal application (LRA) by the NRC staff, STPNOC made commitments related to aging management programs, aging management reviews, and time-limited aging analyses, as applicable, related to managing the aging effects of structures and components prior to the period of extended operation (PEO). The list of these commitments, as well as the implementation schedules and the sources for each commitment, was included as a table in Appendix A to the SER with Open Items.

In Section 1.7, "Summary of Proposed License Conditions," of the SER with Open Items, the staff stated that following its review of the LRA, including subsequent information and clarifications provided by the applicant, it identified proposed license conditions. The first license condition requires the applicant to include the updated final safety analysis report (UFSAR) supplement, required by 10 CFR 54.21(d) in the next UFSAR update, required by 10 CFR 50.71(e), following the issuance of the renewed licenses. It states that the applicant may make changes to the programs and activities described in the UFSAR supplement provided the applicant evaluates such changes in accordance with the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section..

The second license condition will state, in part, that the applicant's UFSAR supplement describes certain programs to be implemented and activities to be completed prior to the PEO and that the applicant shall implement those new programs and enhancements to existing programs as noted in certain commitments no later than 6 months prior to the PEO. The specific license condition will also state that the applicant shall complete those activities as noted in certain commitments by the 6-month date prior to the PEO or the end of the last refueling outage prior to the PEO, whichever occurs later. Finally, the specific license condition will state that the applicant shall notify the NRC in writing within 30 days of implementing the programs, and include the status of those activities to be completed by the 6-month date prior to the PEO or the end of the last refueling outage prior to the PEO, whichever occurs later.

The NRC plans to revise Appendix A of the SER to align with this guidance and to reformat the license condition to be as follows:

ENCLOSURE

The UFSAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, and as supplemented by Appendix A of NUREG [XXXX], "Safety Evaluation Report Related to the License Renewal of South Texas Project, Units 1 and 2" dated [Month Year], describes certain programs to be implemented and activities to be completed prior to the PEO.

a) The licensee shall implement those new programs and enhancements to existing programs no later than 6 months prior to PEO.
b) The licensee shall complete those inspection and testing activities, as noted in Commitment Nos. x through xx of Appendix A of NUREG XXXX, by the 6-month date prior to PEO or the end of the last refueling outage prior to the PEO, whichever occurs later.

The licensee shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

The staff also notes that in the course of its evaluating multiple commitments to be implemented in the future in order to arrive at a conclusion of reasonable assurance that requirements of 10 CFR 54.29(a) have been met, these license renewal commitments must be incorporated either into a license condition or into a mandated licensing basis document, such as the UFSAR. Those commitments that are incorporated into the UFSAR are typically done so by incorporating each one verbatim (or by a summary and a commitment reference number) into the respective UFSAR summaries in the applicant's LRA Appendix A.

Issue:

As proposed by the applicant and as reflected in the SER Appendix A, the implementation schedule for some commitments may conflict with the implementation schedule intended by the proposed revision to the license condition. In addition, these licensing commitments need to be incorporated either into a license condition or into the applicant's UFSAR summary in such a manner as discussed above.

Request:

1. Identify those commitments to implement new programs and enhancements to existing programs. Indicate the expected date for completing the implementation of each of these programs and enhancements.

2. Identify those commitments to complete inspection or testing activities prior to the PEO. Indicate the expected dates for the completion of each of these inspection and testing activities.

3. For each commitment in the SER Appendix A, identify where and how STPNOC proposes that it be incorporated: into either a license condition or into the STP UFSAR.

RAI 3.0.3-1, Guidance from LR-ISG-2012-02

Background:

Recent industry operating experience (OE) and questions raised during the staff's review of several LRAs has resulted in the staff concluding that several aging management programs (AMP) and aging management review (AMR) items in the LRA may not or do not account for OE involving aging effects such as recurring internal corrosion, corrosion under insulation, and flow blockage in fire water system components. In order to provide updated guidance, the NRC staff has issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13227A361).

Issue:

The staff noted that the applicant may not have incorporated the updated guidance into its AMPs.

Request:

Please provide details on how the updated guidance of LR-ISG-2012-02 has been accounted for in your AMPs and AMR Tables or provide adequate justification why incorporation is not required.

RAI 3.0.3-2, Loss of coating integrity for Service Level III coatings

Background:

Recent industry OE and questions raised during the staff's review of several LRAs have resulted in the staff concluding that several AMPs and AMR items in the LRA may not or do not account for loss of coating integrity for Service Level III (augmented) coatings.

Issue:

Industry OE indicates that degraded coatings have resulted in unanticipated or accelerated corrosion of the base metal and degraded performance of downstream components (e.g., reduction in flow, drop in pressure, reduction in heat transfer) due to flow blockage. Based on these industry OE examples, the staff has questions related to how the aging effect, loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage (e.g., cavitation damage downstream of a control valve), would be managed for Service level III (augmented) coatings.

For purposes of this RAI, Service Level III (augmented) coatings include those used in areas outside the reactor containment whose failure could adversely affect the safety function of a safety-related structures, systems, and components, or applied to the internal surfaces of in-scope components and whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3) (e.g., fire protection, station blackout).

The term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers that are designed to adhere to a component to protect its surface.

1. The terms "paint" and "linings" should be considered as coatings.

The staff believes that to effectively manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage of Service Level III (augmented) coatings, an AMP should include:

1. Baseline visual inspections of coatings installed on the interior surfaces of in-scope components should be conducted in the 10-year period prior to the period of extended operation.

2. Subsequent periodic inspections where the interval is based on the baseline inspection results. For example:

    a. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections could be conducted after multiple refueling outage intervals (e.g., for example six years, or more if the same coatings are in redundant trains and not exposed to turbulent flow).

    b. If the inspection results do not meet the above; but, a coating specialist has determined that no remediation is required, subsequent inspections could be conducted every other refueling outage interval.

    c. If coating degradation is observed that required repair or replacement, or for newly installed coatings, subsequent inspections should occur at least once during each of the next two refueling outage intervals to establish a performance trend on the coatings.

3. All accessible internal surfaces for tanks and heat exchangers should be inspected. A representative sample of internally coated piping components not less than 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination should be inspected.

4. Coatings specialists and inspectors should be qualified in accordance with an American Society for Testing and Materials International standard endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff guidance associated with a particular standard.

5. Monitoring and trending should include pre-inspection reviews of previous inspection results.

6. The acceptance criteria should include that indications of peeling and delamination are not acceptable. Blistering can be evaluated by a coating specialist; however, physical

testing should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface.

The "Safety Evaluation Report with Open Items Related to the License Renewal of South Texas Project [(STP)], Units 1 and 2," Section 3.0.3.2.6, documents the staff position regarding internal coatings for open-cycle cooling water piping. The staff noted that in light of the recent industry operating experience, including loss of coating integrity at STP, further detail, as requested below, is required for these coatings as well as others installed on the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks.

For further information on managing loss of coating integrity, see Draft LR-ISG-2013-01, "Aging Management of Loss of Coating Integrity for Internal Service Level III (augmented) Coatings," (ADAMS Accession Number ML13262A442).

Request:

If coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping components, heat exchangers, and tanks), state how loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage will be managed, including:

1. the inspection method
2. the parameters to be inspected
3. when inspections will commence and the frequency of subsequent inspections
4. the extent of inspections and the basis for the extent of inspections if it is not 100 percent
5. the training and qualification of individuals involved in coating inspections
6. how trending of coating degradation will be conducted
7. acceptance criteria
8. corrective actions for coatings that do not meet acceptance criteria, and
9. the program(s) that will be augmented to include the above activities.

If necessary, provide revisions to LRA Section 3, Table 2s, Appendix A, and Appendix B.

Letter to D. W. Rencurrel from John W. Daily dated March 6, 2014

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