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PSEG Nuclear LLC

Technical Specification 6.9.1.10

LR-N21-0019

February 25, 2021

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

Salem Generating Station, Unit 1
Renewed Facility Operating License No. DPR-70
NRC Docket No. 50-272

Subject: Response to Request for Additional Information (RAI), Re: Steam Generator Tube Inspection Report (ML20261H589)

Reference: NRC email to PSEG, "Request for Additional Information – Salem Unit 1 – Steam Generator Tube Inspection Report (EPID L-2020-LRO-0057)," dated January 21, 2021 (ADAMS Accession No. ML21021A259)

In the referenced email, the Nuclear Regulatory Commission (NRC) requested PSEG Nuclear LLC (PSEG) to provide additional information in order to complete the review of the Steam Generator Tube Inspection Report – March 2020. Attachment 1 provides a response to the request for additional information.

There are no regulatory commitments contained in this letter.

Should you have any questions regarding this submittal, please contact Mr. Thomas Cachaza at 856-339-5038.

Sincerely,

Richard DeSanctis
Plant Manager
Salem Generating Station

Attachment:
1. Response to Request for Additional Information

cc: Mr. D. Lew, Administrator, Region I, NRC
Mr. J. Kim, Project Manager, NRC
NRC Senior Resident Inspector, Salem
Mr. P. Mulligan, Chief, NJBNE
Salem Commitment Tracking Coordinator
Corporate Commitment Tracking Coordinator

Attachment 1

Response to Request for Additional Information

REQUESTS FOR ADDITIONAL INFORMATION REGARDING SALEM GENERATING STATION UNIT NO. 1 REGARDING STEAM GENERATOR TUBE INSPECTION REPORT

EPID L-2020-LRO-0057

By letter dated September 17, 2020 (Agencywide Document Access and Management System Accession No. ML20261H589) PSEG Nuclear, LLC. (the licensee) submitted information summarizing the results of the spring 2020 steam generator (SG) inspections at Salem Nuclear Generating Station, Unit 1.

In Appendix A of Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR), General Design Criteria (GDC) 14, 15, 30, 31, and 32, define requirements for the structural and leakage integrity of the RCPB. As part of the RCPB, the SG tubes must also meet the requirements of 10 CFR 50.55a with respect to inspection and repair requirements of the ASME Code. All pressurized water reactors have Technical Specifications (TS) according to 10 CFR 50.36 that include a SG Program with specific criteria for the structural and leakage integrity, repair, and inspection of SG tubes. These inspections were performed during a refueling outage in March 2020. Technical Specification (TS) 6.9.1.10 requires that a report be submitted within 180 days after the initial entry into hot shutdown following SG inspections performed in accordance with TS 6.8.4.i, which requires that an SG Program be established and implemented to ensure SG tube integrity is maintained.

To complete its evaluation of the information provided by the licensee, the U.S. Nuclear Regulatory Commission (NRC) staff requests the following information:

1. The May 7, 2018 SG Tube Inspection Report (ML18127A119) referred to the refueling outage in the fall of 2017 as the twenty-fifth refueling outage (1R25). The current report from September 2020 also refers to the March 2020 refueling outage as the twenty-fifth refueling outage (1R25). Please clarify.

   PSEG Response:

   Reference to “1R25” appears in a few locations of the March 2020 inspection report (LR-N20-0062), including the Explanation of Terms section, and responses to Technical Specification 6.9.1.10.a, 6.9.1.10.b, and 6.9.1.10.d. The term “1R25” is meant to refer to the Salem Unit 1 fall 2017 twenty-fifth refueling outage (1R25). The reference to “1R25” in PSEG LR-N20-0062 section 6.9.1.10.a is correct. Reference to “outage 1R25” in PSEG LR-N20-0062 section 6.9.1.10.b and 6.9.1.10.d was incorrect and was meant to refer to the “March 2020 outage”. Also note that the March 2020 outage was not a refueling outage, however it was a SG inspection outage.

2. Page 2 of the subject report appears to indicate that there are over expansion (OEX) indications within the hydraulically expanded tubesheet that have localized variations in tube diameter that are greater than 0.25 inches. Please confirm this understanding or

clarify the correct value. If true, please discuss the largest OEX indication in the Salem U1 SGs and the total number of OEX indications greater than 0.25 inches.

PSEG Response:

An internal tubesheet overexpansion (OEX) is defined as a profile deviation equal to 1.5 mils (0.0015 inches) or greater from the average of the expanded tubesheet region profile and has an axial extent greater than 0.25 inch. The definition of internal tubesheet overexpansion is consistent with industry guidance provided in the 2005 timeframe, in response to operating experience including NRC Information Notice 2005-09.

Also reference our response to RAI No. 1 in our letter PSEG LR-N14-0107, dated April 24, 2014 (ML14115A016).

3. Paragraph g on page 4 of the subject report refers to the tube in row 57 column 54 three times, in the discussion of in situ pressure testing that was performed on three tubes because of foreign object wear. The tubes affected by foreign object wear are documented in the table in Attachment 9. Please confirm that the three tubes in situ pressure tested were the three tubes with 100 percent through wall indications shown in the table in Attachment 9.

PSEG Response:

Tubes with 100 percent through wall indications in SG 14 at Row 57 Column 54, Row 58 Column 54, and Row 58 Column 55 were in-situ pressure tested, consistent with table in Attachment 9 of LR-N20-0062.

4. Please discuss the scope and results of any secondary side inspections, including foreign object search and retrieval, upper bundle inspections, steam drum, and moisture separator inspections. Also, please discuss the scope and results of any visual exams of plugs and the primary channel head that were performed.

PSEG Response:

Prior to water lancing (sludge lancing) in SG 14, a secondary side remote visual inspection on the flow distribution baffle plate was performed based on eddy current indications of foreign object and tube degradation in the hot leg side of Row 57 Column 54, Row 58 Column 54, Row 58 Column 55, and Row 59 Column 55. A cylindrical tapered metal object approximately 2 inches long and 0.4 inches in diameter was discovered between these tubes, and removed from SG 14. Also see response to RAI#5.

In each steam generator, following top of tubesheet (TTS) and flow distribution baffle (FDB) plate water lancing, visual inspections and Foreign Object Search and Retrieval (FOSAR) were performed. These inspections included the full length of the no tube lane (area between row 1 tubes), a minimum of three inner bundle passes (hot leg and cold leg), and completely around the annulus tube areas (shell-to-tube bundle region, including periphery tubes). The annulus / periphery tubes inspection included view into the bundle (from the annulus region) allowing inspection between the periphery tubes into the bundle. The purpose of these inspections was to identify and remove foreign material and to assess the effectiveness of the water lancing. Approximately 110 pounds of sludge was removed from all four SGs (total). During the water lance process, a strainer is used to separate material removed from the SGs. Generally, all of the SGs had several small metallic, foil like materials, and rock/pebble like materials. Some benign tube scale deposits and sludge material are also typically observed during secondary side inspections. FOSAR was performed (as-possible) at tube locations identified by ECT for potential loose parts (PLP), and these tube locations and tubes in immediate proximity (bounding) to PLP/foreign material were also further reviewed with bobbin and array probe inspections. A summary of foreign material, other than sludge rocks, identified by FOSAR is provided in the following table. Foreign material identified in the SGs and not able to be removed was evaluated as having no significant consequence to tube integrity and continued plant operation.

Description (Length x Width x Depth)	**Location**	**Comment**
Steam Generator 11		
Bent Foil Piece (0.5” x 0.01” x 0.4”)	58-69, 57-69, 57-68, 58-68 TSH	Object was a non-magnetic bent piece of foil. Removed from the SG. All affected and bounding tubes were No Degradation Detected (NDD) with Bobbin and Array.
Thin Metallic Strip (0.63” x 0.13” x 0.004”)	56-72, 55-72, 56-73, 55-73 TSH	Object was a magnetic thin metallic strip. Removed from the SG. All affected and bounding tubes were NDD with Bobbin and Array.
Steam Generator 12		
Metal object from 1R20 (1.0” L x 0.50” W)	20-42, 21-41, 21-42, 20-43 TSH	Object is observed in the same location and unchanged since 1R25 inspection All bounding tubes were NDD with Bobbin and Array.
Metallic Object (0.69” x 0.10” x 0.31”)	55-77 FBH	Visual inspection confirmed metallic, magnetic object at location of PLP. Object was removed from the SG. All affected and bounding tubes were NDD with Bobbin and Array.

Description (Length x Width x Depth)	Location	Comment
Steam Generator 13		
Loose scale / Small Metallic Material	2-17 TSC	Visual inspections confirmed loose scale at TTS at PLP location. Using a magnet, a small sliver (i.e., eyelash) of magnetic material was removed. The scale was broken up during retrieval. All affected and bounding tubes were NDD with Bobbin and Array.
Steam Generator 14		
Metal cylinder (2.0” L x 0.4” diameter)	57-54, 57-55, 58-54, 58-55, 59-55 FBH	Object was visually confirmed near/between 5 tubes, and removed. Wear was identified by ECT and also visually identified on four tubes. All bounding tubes were NDD with Bobbin and Array.
Unidentified object lodged in sludge (0.30” x 0.25” x 0.10”)	7-41 TSH	Object confirmed at ECT PLP location. Multiple attempts at retrieval confirmed object was stuck to the tubesheet. All affected and bounding tubes were NDD with Bobbin and Array.

Secondary side inspections of the upper bundle, steam drum, and moisture separators were not performed during the March 2020 outage. However, remote visual inspections were performed in SG 14 at the top of the 7^{th} tube support plate (TSP), no-tube lane and wrapper plug locations, with no conditions adverse to quality observed.

Primary side channel head internals visual inspections were completed in all four steam generators, both hot leg and cold leg. The channel head internals include surfaces of the tubesheet, channel head cladding, all previously installed tube plugs, divider plate and associated welds. No conditions adverse to quality were observed.

5. In May 2017, the licensee identified a transitory (lasting for approximately two weeks) primary-to-secondary leak in SG 13. In the subsequent refueling outage, October 2017, the source of the leak was determined to be located on the cold-leg side of the SG, in the tube in row 2 column 91. The eddy current signal in this tube was characterized as an indication of loose part wear. In February 2020, the licensee identified a primary-to-secondary leak in SG 14, which resulted in a forced shutdown of Salem Unit 1. The resulting inspections revealed four tubes with significant through-wall wear from a foreign object, of which three tubes were 100 percent through-wall. Please discuss any analyses you have performed to assess the possible source of loose part intrusions and any actions you have taken with regards to strengthening your foreign material exclusion program.

PSEG Response:

Both the 2017 and 2020 Salem Unit 1 leak events were evaluated in Root Cause Evaluations. The 2017 Root Cause was determined to be the Foreign Material Exclusion (FME) Program implementation has not been effective in preventing a steam generator tube leak. Planners, workers, and supervisors do not consistently apply the FME standards in accordance with FME Program in the PWR secondary feedwater and condensate systems. A Contributing Cause was also identified as the FME Program has not been maintained to industry standards with regard to High Risk systems and components. Corrective actions were created to resolve the causes and improve performance. Subsequent to the 2020 leak event, another Root Cause was performed and included several actions and review of effectiveness of corrective actions from the 2017 Root Cause. In summary, the 2020 Root Cause was determined to be legacy foreign material exclusion practices led to foreign material introduction that resulted in a primary to secondary tube leak in 14 SG. The 2020 Root Cause also determined the most probable cause is that the foreign material introduced into 14 SG resulted from maintenance activities involving a system breach of Main Feedwater, Auxiliary Feedwater, SGs, or Chemical Feed (CF) systems prior to the implementation of the 2017 Root Cause corrective actions to improve the FME program and practices. Improvements in FME practices were noted in the 2020 Root Cause, however additional actions to further strengthen the FME program were identified.

Although the 2017 leak event could not locate a specific foreign object as the cause, the 2020 leak event did recover a foreign object (part) at the location of the tube leak. The recovered part underwent material analyses to identify composition, heat treated Type 416 stainless steel, and to aid in identifying the source of the material. In order to determine if the foreign object that caused the 14 SG tube wear was from a degraded component, a comprehensive flow path component review was completed. This review assessed over 160 components that have a direct flow path to the Steam Generators. This review concluded that the part discovered in SG 14 that caused the tube leak did not come from a degraded component. Additionally, a comprehensive review of secondary system breach work activities performed during S1R25 and subsequently up to this event was performed to assess if the identified material was potentially introduced during this time period. A review of notifications, work order confirmations, and work order comments/feedback did not identify any lost, broken or missing parts or materials during the execution of work. The exact source of the recovered part from SG 14 was indeterminate.

PSEG Nuclear has taken several actions to strengthen the site's FME program, specifically; procedure revisions to align with INPO and EPRI guidelines, expansion of FME coordinator duties including for outages and increased monitoring and field observations, review and approval of FMEA 1 (debris intrusion that can affect steam generator tubes) project plans, updates and publication of FME performance indicators for management review, and FME program assessment periodicity requirements.

6. In the Fall 2017 refueling outage, the licensee was evaluating tapered welded plugs manufactured by Areva that possibly had fatigue life issues. During the outage, it was determined that the evaluation that call the fatigue life into question was determined to

be overly conservative, and that the plugs were good for at least two additional operating cycles, or until 2020. An additional analysis was to be performed that would determine if the plugs were acceptable for the full 40-year design life. Please discuss the final disposition of the analyses performed on the plugs in question.

PSEG Response:

Framatome (formally Areva) completed fatigue evaluation of the tapered welded plugs concluding all 10 installed plugs satisfy stress fatigue requirements for the anticipated plant transient/cycles for the renewed plant license and will be monitored through the fatigue monitoring program.