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South Texas Project Electric Generating Station P.O. Box 289 Wadsworth, Texas 77483

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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
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Rockville, MD 20852-2738

South Texas Project
Unit 1
Docket No. STN 50-498
Response to Request for Additional Information: 1RE13 Inservice Inspection
Summary Report for Steam Generator Tubing (TAC No. MD5948)

Reference: Correspondence from Brandon Jenewein to NRC Document Control Desk, "1RE13 Inservice Inspection Summary Report for Steam Generator Tubing," dated April 16, 2007 (ML071140087)

By the referenced correspondence, the STP Nuclear Operating Company (STPNOC) provided the results of Unit 1 steam generator tube inspections performed during the Fall 2006 refueling outage (1RE13). Pursuant to a request for additional information from the NRC staff, STPNOC submits the attached responses.

There are no commitments in this letter.

If there are any questions regarding this report, please contact either Mr. P. L. Walker at (361) 972-8392 or me at (361) 972-7431.

Brandon Jenewein
Manager,
Testing/Programs

PLW

Enclosure: Response to Request for Additional Information: 1RE13 Inservice Inspection Summary Report for Steam Generator Tubing (TAC No. MD5948)

STI: 32258374

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SOUTH TEXAS PROJECT
UNIT 1
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION:
1RE13 INSERVICE INSPECTION SUMMARY REPORT FOR
STEAM GENERATOR TUBING (TAC NO. MD5948)

1. You state that one tube in Steam Generator (SG) D was plugged (R117 C49) due to a wear depth of 44% at the top of tubesheet on the cold leg due to wear caused by the stabilizer wire. When was this tube last inspected and was this a location where a loose part was present during the prior inspection?

   Response:

   The most recent inspection of SG 1D was Fall 2006 (1RE13). The first inspection following influx of the loose stabilizer wire was Spring 2005 (1RE12). Previous inspection found no wear at the location, and there were no loose parts present.

2. Please describe the inspection techniques used to perform the upper steam drum, feedring and ninth tube support plate inspections; were they visual or ultrasonic? Please discuss the results of these inspections.

   Response:

   The upper steam drum, feedring, and ninth tube support plate were visually inspected. Visual inspection of the steam drum, feedring, and ninth tube support plate showed no abnormalities. No wear or deformation was observed. The ninth tube support plate and associated tubes showed early stages of magnetite fouling. Fouling is tracked to determine if action to remove the fouling is necessary.

3. For each RFO or SG tube inspection since installation of the replacement SGs, please provide the cumulative effective full power months (EFPM) that the SGs have operated.

   Response:

OUTAGE	EFPM	CUMULATIVE
1RE10	16.40	16.40
1RE11	16.57	32.97
1RE12	18.68	51.65
1RE13	17.41	69.06

4. Please clarify the following sentence: "A more extensive eddy current and visual inspection of steam generator 1D was developed to support the planned 3 cycle inspection interval for the Unit 1 steam generators." Is this statement intended to indicate that a more robust examination was performed in steam generator 1D in an effort to justify extending the interval between inspections from 1 cycle to 3 cycles?

Response:

That is not the intent. The inspection interval for all four steam generators was already three cycles. The more extensive scope was due to the loose parts issue related to lost feedwater heater tube stabilization cable. The objective was to retrieve all cable fragments in SG 1D, combined with inspection results that would support three cycles of operation between inspections. At the conclusion of 1RE12, however, with the potential for wire remaining in SG 1D in addition to other potential sources of wear, the decision was made to operate for one cycle only between inspections of SG 1D. SG 1D is scheduled for inspection and wire retrieval during the Spring 2008 refueling outage (1RE14). The remaining steam generators are on a three-cycle inspection interval.

5. Please clarify the following sentence: "+Point inspection of 20% of the first two rows of U-bend looking*..." Were these tubes inspected full length with a +Point coil or was only the U-bend region of 20% of the row 1 and 2 tubes inspected with a +Point coil?

   Response:

   Only the U-bend region of 20% of rows 1 and 2 was inspected.

6. For steam generators 1A, 1B, and 1C, a +Point inspection of all tube bulges in the tubesheet were performed. For steam generator 1D a +Point inspection of all tube bulges and overexpansions in the tubesheet was performed. Please discuss why the overexpansions in steam generators 1A, 1B, and 1C were not inspected.

   Response:

   The intended inspection scope for 1RE13 was inspection of all tube bulges and overexpansions in the four Unit 1 steam generators. Discussion of overexpansion inspections for steam generators 1A, 1B, and 1C was inadvertently omitted from the inservice inspection summary report for 1RE13 (April 16, 2007) (ML071140087).

   In addition, STPNOC has determined that not all bulges and overexpansions were inspected during 1RE13. Bulge and overexpansion calls identified prior to service for the four steam generators were to be included in the inspection scope. However, those bulge and overexpansion calls were inadvertently omitted from the inspection scope. Stress corrosion cracking in bulges and overexpansions are not potential degradation mechanisms for Inconel 690 tube material; therefore, these inspections are discretionary and not required for maintaining steam generator operability.

   STPNOC intends to inspect a sample of bulges and overexpansions during future inspection outages.

7. For steam generators 1A, 1B, and 1C, it was indicated that an eddy current inspection would be performed on tubes near unretrieved possible loose parts, if possible. Please clarify why it may not be possible to inspect these tubes. If these tubes are not inspectable, please discuss why these tubes were not plugged and how you confirmed (or will confirm) that these tubes have adequate integrity.

   Response:

   Steam generators 1A, 1B, or 1C were to be inspected in areas where previously identified possible loose parts (PLPs) had not been retrieved. Tube damage relative to inspectability has not been the case. If a tube had been plugged where a loose part was still present, it would not be possible to inspect that particular tube. This condition

has not been encountered. All tubes with previously identified PLPs were inspected with no degradation found.

8. Please discuss the results of the tube scale profiling performed in steam generator 1C.

Response:

Tube scale profiling showed light scaling mostly located in the upper bundle. Scale profiling in conjunction with upper bundle visual inspections will be used to determine appropriate future actions.

Scale profiling is part of the steam generator long-term inspection plan.

9. Regarding the table summarizing the scope of your eddy current inspections, please clarify the following:

a. Please clarify the hot- and cold-leg columns. Do the numbers in these columns indicate the number of tubes that were inspected from either the hot or cold leg. For example, were 4330 tubes in steam generator 1A inspected full length from the hot leg, and an additional 384 tubes inspected full length from the cold leg?

Response:

For the example above, the breakdown would be as follows:

Hot Leg Side				
Extent	TEC – TEH	9C – TEH	9H – TEH	Total
# of Tubes	3946	229	155	4330
Cold Leg Side				
Extent		9C – TEC	9H – TEC	Total
# of Tubes	NA	229	155	384

Note: The total number of tubes inspected, tube-end to tube-end, is 4330. These are pre-determined inspection plans for the bobbin coil scope. Inspections are carried out from the Hot Leg and/or Cold Leg depending on tube locations, acquisition system availability, probe configurations, etc.

b. There appears to be a disproportionate number of dents/dings in steam generator 1A. Please clarify.

Response:

There are more dents and dings in SG 1A than in the other Unit 1 steam generators. These minor dents and dings are related to the fabrication process and have been evaluated. These minor dings are not expected to cause corrosion-related cracking on the Inconel 690 tubes, and are to be monitored in future inspections.

c. Please clarify the "PLPs [possible loose parts] Inspected" and "PLP Calls" rows. If there were no PLP Calls, why were any PLPs inspected?

Response:

"PLPs Inspected" is the number of tubes inspected as special interest for PLP screening. In the case of SG 1A for example, a total of 88 inspections were performed to identify PLPs. The sum comes from tube locations with possible loose parts reported plus the "boxed-in" programs where the original call was surrounded. If something was reported during the box-in program, additional tubes were added to bound this new call.

The 88 tubes inspected are most likely the result of 6 - 8 tube locations originally identified as having a possible loose part. The additional tubes were part of the box-in.

Although no PLPs had been called by the conclusion of the inspections, the tubes examined (88) for PLPs remain in the database.

10. Please confirm that no wear was found at the tube support plate elevations.

Response:

No tube wear was found at the support plates.

11. Regarding the PLP indications, please discuss the extent to which these indications were found during the bobbin, rotating probe, or both inspections (i.e., provide the number of indications detected with only the bobbin probe, the number of indications detected with only the rotating probe, and the number of indications detected with both probes).

Response:

For SG 1D, a total of 20 calls were originally made with a bobbin. These calls have a corresponding rotating pancake coil (RPC) probe at the same location. In some cases the rotating coil confirmed the location as PLP. In other cases the location was identified as INF (indication not found) – meaning the bobbin call was not accurate. This would explain why the bobbin identified 20 and the RPC probe a lesser amount for those tube locations. RPC was the technique which identified the majority (several hundred) PLPs called during the inspection of SG 1D.

12. Regarding the visual inspections at the top of the tubesheet and at the flow distribution baffle in steam generator 1D, please address the following:

(a) the source of the PLP indications at the flow distribution baffle,

Response:

The source of the PLP indications at the flow distribution baffle is feedwater heater tube stabilizer cable wire fragments, similar to the PLPs at the top of the tube sheet.

(b) the number of loose parts/foreign objects left in steam generator 1D at the top of the tubesheet and the flow distribution baffle including their location and size. How much stabilizer wire remains unaccounted for in the SGs?

Response:

Five pieces of wire were left behind a stayrod on the top of the tube sheet. The longest piece is 2.5". None of the parts is expected to cause wear in the low

velocity zone behind the stayrod. Removal of these loose parts is planned for 1RE14.

Based on PLP calls, approximately 250-300 pieces of wire are located on the flow distribution baffle (FDB) and are distributed over the entire FDB. These pieces are estimated to be up to 2.5" long. It is believed that several grams of wire remain in SG 1D, most of which are likely on the FDB.

STPNOC plans to open the inspection port on the flow distribution baffle, first tube support plate, and second tube support plate and inspect every row/column during 1RE14. STPNOC will attempt to retrieve every identified loose part.

13. Please discuss the nature of the restriction in the one tube in steam generator 1B.

Response:

During fabrication of SG 1B, a temporary fabrication wedge evidently was left in the steam generator. When the SG was righted into a vertical position, the temporary wedge fell to the top of the tubesheet, striking one tube and causing the restriction. This wedge was identified and removed. The tube is included in the inspection scope during each inspection outage.

14. In the Table on page 7 there are several locations/tubes that were listed as "retest" tubes. Please confirm that all of these tubes/locations were inspected. Please clarify how the tubes "not cleared by +Point" were dispositioned. In addition, please clarify the source/nature of the one dent indication in steam generator 1B and the three manufacturing burnish mark signals in SG 1B and 1D. (It is the staff's understanding that when a bobbin indication is not traceable back to the preservice inspection, it is considered an indication that is service-induced such as the one dent that was "not cleared" and the three manufacturing burnish mark signals).

Response:

Locations/tubes listed as "retest" were retested with satisfactory results.

For tubes not cleared by +Point, a current bobbin signal may be cleared by way of historical data review or engineering justification in lieu of RPC examination if the morphology is understood. A specific row-column location and signal can be addressed if further information is required.

The particular signal was observed and recorded in 1999 during the preservice inspection. During the first inservice inspection (2001), the signal fell below the recording criterion of two volts and was not called. In 2006 (1RE13), the signal was observed again but this time measured greater than two volts (2.02 volts) and was called. The signal should be considered a product of fabrication, and not service-induced.

The situation for the three manufacturing burnish signals is similar. A signal will not necessarily meet the criterion for a call at every inspection. These signals were observed during preservice inspection and during inservice inspections (1RE10 and 1RE13) and, because they are traceable back to the preservice inspection, they are not a service-induced condition.

15. In several instances, you discuss "active degradation mechanisms." In the context of this report, please confirm that "active degradation mechanism" is referring to any

service-induced deterioration of the tubes due to mechanical wear or corrosion (regardless of the depth of the deterioration).

Response:

The term "Active Degradation Mechanism" is defined under Appendix F of the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines (Revision 6) which describes "Active Damage Mechanism" as:

> A combination of 10 or more new indications (≥ 20% through-wall) of thinning, pitting, wear (excluding loose part wear), or impingement and previous indications that display an average growth rate ≥ 25% of the repair limit in one inspection-to-inspection interval in any one steam generator,
>
> One or more new or previously identified indications (≥ 20% through-wall) which display a growth equal to or greater than the repair limit in one inspection-to-inspection interval, or
>
> Any crack indication (outside diameter intergranular attack/stress corrosion cracking or primary-side stress corrosion cracking).

STPNOC is in the process of updating the South Texas Project program and procedures to meet Revision 7 of the Examination Guidelines. Revision 7 includes "existing" as part of the definition of "Active Damage Mechanism".

With the exception of loose parts wear in steam generator 1D due to loose wire fragments, there are no known degradation mechanisms working in the Unit 1 steam generators.