Nuclear Operating Company
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
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

South Texas Project
Unit 2
Docket No. STN 50-499
Response to Request for Additional Information Regarding
2RE10 Steam Generator Inspection

Reference: Letter, J. W. Crenshaw to NRC Document Control Desk, "Special Report – 2RE10 Refueling Outage Inservice Inspection Results for Steam Generator Tubing," dated June 16, 2004 (NOC-AE-04001741)

The referenced letter submitted a summary report describing the results of the steam generator tube inservice inspection performed during refueling outage 2RE10. It satisfied the reporting requirements of ASME Section XI, Article IWA-6230, and Section 4.4.5.5b. of the South Texas Project Technical Specifications. After reviewing the referenced letter, the NRC requested additional information. This letter provides that additional information.

There are no commitments in this letter.

If there are any questions regarding this additional information, please contact John Conly at (361) 972-7336 or me at (361) 972-7074.

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jtc

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Response to Request for Additional Information

1. Provide the following information concerning the design of your replacement steam generators (SGs): tube manufacturer, tube spacing, tube support and anti-vibration bar design and material, tubesheet thickness, method used to expand tubes into tubesheet, radiuses of curvature and location (i.e., rows one through n) of thermally stress-relieved U-bends. In addition, please include a tubesheet map and a sketch depicting your tube support (including anti-vibration bars) naming convention.

Response:

The requested information was included as Attachment 4 to South Texas Project (STP) letter NOC-AE-04001765 dated August 12, 2004.

2. Many indications were considered as special interest and inspected with a +Point™ coil because they exhibited a change from the pre-service eddy current behavior at the same locations. Discuss what constituted a change in the signal and your technical basis for this criteria (e.g., Is it based on test repeatability?). In addition, please discuss the cause of the signal change.

Response:

Analysis of bobbin coil eddy current (ET) data was performed using the "Steam Generator Eddy Current Data Analysis Guidelines for Inservice Inspections at South Texas." In the section entitled "Reporting Criteria (Bobbin Coil)," the guideline states "Any 'new' signals which resemble MBM's or MMB's that did not appear on baseline data or any previous MBM or MMB calls which show a change in size or character should be examined carefully and evaluated conservatively." During the analysis of the ET data, it was not permitted to make the judgement that a condition was not service-induced solely on the basis that its eddy current test signal had remained unchanged from the preservice inspection. The Analysis Technique Specification Sheet for the resolution of analysis results states the criteria as a "CHANGE in signal attributes (voltage, appearance) and/or 15 degree CCW rotation for freespan and 10 degree CCW rotation at support structures."

The judgement of whether an eddy current signal had changed sufficiently from the pre-service inspection was made by certified qualified data analysts. Signals with relatively small amplitudes or phase angles at the margins of the flaw range benefited the most from the consideration of signal change to detect degradation. The criteria for recognizing real change of the tube condition defined in the analysis technique specification sheet was based on the repeatability of the bobbin coil technique for these marginal signals.

Signals that were categorized as having changed since the pre-service inspection were identified predominantly on the basis of phase rotation. Such a signal may be from a physical imperfection

in the tube from manufacture, a metallurgical imperfection (such as an alloy anomaly or permeability change), a scratch or abrasion of the tube from steam generator manufacture, etc. that is so small that it is not detectable during the pre-service inspection. The phase rotation is believed to be caused by exposure of the tubes to operating temperature during their first fuel cycle resulting in a localized "relaxation" of the metallurgical condition. It is known that when alloys, including Alloys 600 and 690, experience this sequence of conditions, they have a change in electrical conductivity. This conductivity change is not proportionate to the size of the imperfection. Experience at other plants with replacement steam generators indicates that the signals cease to rotate further after the first cycle of operation. All of the anomalous indications were examined with a rotating coil (+Point™) probe. No discernable indication of degradation was reported by the rotating coil eddy current tests.

3. Recently, a plant identified an input error (human error) in their computer data screen (CDS) setup which resulted in a ½ - inch gap in which the data was not analyzed by the CDS. You indicated that your primary analysis was performed with an automated data screening software package. Please verify that the entire length of each tube was examined during the evaluation (i.e., verify there were no gaps in the input such that a portion of the data was not properly evaluated).

Response:

Bobbin coil eddy current test data was acquired over the entire length of each tube in service. There were no gaps in the analysis of the bobbin coil eddy current test data such that a portion of the data was not properly examined.

A degradation assessment was performed and documented just prior to the 2RE10 refueling outage. The degradation assessment, which included an element of judgment, determined in part, that there was no potential for degradation within the tubesheet.

The terms "primary" and "secondary" as used in the report require clarification. These are the titles for the "primary" analysis team or the "secondary" analysis team. The terms have been used traditionally in the industry to distinguish between the two teams in the context of contractual responsibility, scope of work, data flow, etc. However, the work product from the secondary analysis team is of the same quality, validity, and stature as that from the primary analysis team.

The primary analysis team analyzed the 2RE10 bobbin coil eddy current data for all the tubes tested using automated data screening software. A specific review was conducted by both Westinghouse and the STP eddy current test engineer, which verified that there were no errors in the automated data screening software inputs. The extraneous signals caused by the bobbin coil entering or leaving the tube end made it necessary to begin or end computer automated data screening at a point 2.5 inches from the tube end. This was a planned activity. The extraneous signals caused by the U-bend geometry and anti-vibration bars made it necessary to apply the

algorithm for detecting loose parts only to the straight tube regions. This was also a planned activity.

The secondary analysis team also analyzed the 2RE10 bobbin coil eddy current data for all the tubes tested using software (without using automated screening) over the full length of the tubes, from tube end to tube end. Consequently, there were no gaps in the analysis of the bobbin coil eddy current test data such that a portion of the data was not properly examined.

Furthermore, a rotating probe eddy current test technique was applied to 228 portions of selected tubes in each of the four steam generators (912 total). This examination was through the full tube sheet depth. The tube portions tested extended from the hot leg tube end to a point 3.0 inches above the hot leg tubesheet secondary face. All of this rotating probe data was analyzed twice, by the primary and secondary analysis team, using software (without using automated screening).

4. Please discuss the source of origin for the foreign objects found during your foreign object search and retrieval (FOSAR) and discuss how they were dispositioned.

Response:

The foreign material consisted of small pieces of spiral-wound gasket material from the feedwater system, which were removed from the steam generators by sludge lancing and foreign object removal using mechanical grippers. All foreign objects were identified in the Corrective Action Program. The potential for non-identified pieces of spiral-wound gasket material not being removed or being later introduced was addressed by a bounding wear analysis, which determined no unacceptable wear (related to the structural performance integrity criteria) would occur at the worst potential location, considering the highest areas of fluid flow and maximum tube vibration, for approximately 12 years.

5. With respect to the inspections at dented/dinged locations, please address the following:

   a. On page 8 of your in-service inspection report, you used three different letter codes to identify dings and dents: DNG (ding), DNS (ding or dent with a signal confirmed to be from a non-flaw condition), and DNT (dent located at a tube support structure only). On page 7 of the same report, you indicated that you performed a +Point™ inspection of 20% of dings at supports 5.0 V or less and another +Point™ inspection of all dings greater than 5.0 V. Please clarify the criteria used to differentiate a ding from a dent. Please clarify the inspection scope of dings/dents.

Response:

STP Nuclear Operating Company used the Westinghouse definitions of "ding" and "dent" in the inservice inspection report:

DNG-"Ding", a manufacturing-induced deformation of the tube in the free span or at a support structure.

DNT-"Dent", a service-induced deformation on the tube in the free span or at a support structure.

The 2RE10 inspection scope defined by the Degradation Assessment consisted of two aspects. The first inspection was of tubes with any unintended geometric deformations greater than 5 volts, which are large enough to potentially mask axial flaws. The second inspection of a 20% sample of deformations at support structures was added to the Degradation Assessment just prior to the outage to address the Palo Verde emergent condition caused by crating the steam generator tubes. This additional scope was in response to an industry issue at another plant involving the fabrication-induced screw damage of a tube at a support structure location where the support structure may have made detection more difficult. This was very recent industry experience just evolving at the time of the 2RE10 inspection and the additional inspection scope was proactive on the part of STP to this emerging information.

b. You indicated in your in-service inspection report that a number of dings and dents signals were identified. Were these indications present since the pre-service inspection? If so, please discuss whether they have changed since the pre-service inspection and the reasons for any change. If they were not present in the pre-service inspection, please discuss the cause of the dings/dents.

Response:

These indications were present since the pre-service inspection in almost all cases. Some of the signals showed a slight phase change from the baseline inspection. This phenomenon has been noted at other plants after the first cycle of operation, i.e., after the tubes go through a "heat cycle." Since the anomalous signals are quite small, a slight change in conductivity in the tube, such as can occur from a heat cycle, can affect the signal phase. It was also noted on some indications, that the absolute channel showed a larger offset during the first inservice inspection compared to the baseline signal. There is no differential signal change and the absolute signals show no phase change between frequencies, again indicating a slight conductivity variation from the nominal tube.

Three small dent signals were identified by the bobbin coil examination that were not in the pre-service inspection report. No loose parts were visible in these areas. Two of these dent signals were examined in the MRPC scope. The one dent signal not

examined by MRPC was in the freespan in steam generator "C". It was less than 1 volt and had no indication of flaw-like characteristics or wall loss. Its cause is unknown.

6. With respect to the examination scope identified in the pre-service inspection summary report (ML030710429), please address the following:

   a. On page 3 of the report you indicated that you performed rotating probe inspections where over-expansions were longer than 0.005 inches from 1 inch above the secondary face to the tube end. Please clarify this statement. For example, were the locations inspected 1.005 inches above the secondary face of the tubesheet to the tube end? In addition, please provide the number of under and over expanded tubes and discuss the scope and results of any rotating probe inspections performed at these locations during your 2004 outage.

Response:

For perspective, it should be noted that the fabrication of steam generators requires a compromise between minimizing the secondary tubesheet crevice and yet not creating over-expansions or "bulges." To achieve this compromise, the STP fabrication requirements limited the crevice depth, and a minimum crevice average depth was achieved. The process specifications required that no increases in delta radius greater than 0.005" were allowed without engineering evaluation. The 0.005" delta radius limit is five times smaller than that radius shown to not increase stresses or corrosion susceptibility by stress index and accelerated corrosion testing equivalent to ~ 30 years at temperature significantly higher than STP's operating temperature.

During the fabrication process, a mechanical gage Advance Extensiometric System was used to provide a graphic of the tube expansion profile. Diatest gages were also employed along with eddy current, including fabrication in-process motorized rotating coil examinations, to insure that no condition that would increase tube expansion stresses above an acceptable level were placed into service. For STP, the conservative stress limit of 50% of yield was imposed for outside tube expansion residual stresses. Each measurement method has benefits and limitations, and all differ in their results, as all must depend on some method of tube-to-tubesheet expansion last contact point determination.

The statement regarding rotating probe inspections of longer over-expansions was trying to convey that if an over-expansion was more than 0.005" (axially) above the top of tube sheet, then that tube was examined from one inch above the tube sheet to the tube end.

According to the Pre-Service Inspection Senior Analysts Summary Report, a total of 52 over-expansions were called during the pre-service inspection (PSI). This is with the

inherent limitations of bobbin coil eddy current to correctly determine this condition. No under-expansions were identified.

No special inspection scope of over-expansion was planned or required during the 2RE10 inspection. However, the planned inspection scope did include the random selection of 3% of the tubesheet expansions and the inspection continued full depth through the tubesheet. No unacceptable conditions were found.

b. On page 3 of the report, you indicated that you performed rotating probe inspections at locations below the baffle plate cut out region and on the periphery of the bundle from one inch above to four inches below the secondary face. Please clarify what constitutes the cut out region of the baffle plate and discuss the results of any similar inspections performed during your 2004 outage.

Response:

The central cut out area is a circular symmetric cutout of ~ 43" diameter on the hot and cold leg central bundle position. Refer to Figure 1. No specific inspection of these areas were required or performed during 2RE10. The PSI of the baffle cut out region was performed only to obtain baseline rotating coil data for these areas should STP bobbin coil examinations encounter possible loose parts later in service.

c. On page 2 of the report, you indicated that you performed rotating probe inspections where the largest 20 bulge indications occur from one inch above to four inches below the secondary face. Then on page 9 of your in-service inspection report, you indicated that only two bulges were identified. Please clarify. With respect to the two bulge indications reported in 2004:

(i) Were these indications present since the pre-service inspection? If so, have they changed and why? If so, please discuss whether they have changed since the pre-service inspection and the reasons for any change. If they were not present in the pre-service inspection, please discuss the cause of these indications and the effect on tube integrity.

Response:

Up to 20 inspections were planned if more than 20 were found. However; only two bulges were found. The two bulge indications have been present since the pre-service inspection and they have not changed since the pre-service inspection.

7. With respect to all of the bulge indications in your SGs, please discuss the scope and results of any rotating probe examinations performed during your 2004 outage.

Response:

No special inspection scope of bulges was required or performed during 2RE10.

8. Palo Verde Nuclear Generating Station (PVGNS) replaced their Unit 2 steam generators in December of 2003. After startup, the licensee observed an increase in primary-to-secondary leakage over the following two months. The licensee decided to shutdown the plant to identify the source of the leak. Inspections did not reveal any evidence of in-service degradation associated with the leaking tube, but did confirm the presence of a dent near a vertical support in the middle of the horizontal run of the tube that was detected in the pre-service examination. The dent signal was considered anomalous because it differed from a typical dent signal in that it exhibited some flaw-like characteristics (i.e., it had a vertical component). A comparison with the pre-service inspection data revealed no significant differences. Please discuss whether you observed any similar anomalies in your dent/ding signals.

Response:

The U-tube crating configuration of the STP tubing differed significantly from the crating configuration that allowed the Palo Verde square tube screw damage. The potential for tube crating damage has been assessed in our Corrective Action Program and found not to apply to the STP crating arrangement.

The 2RE10 Degradation Assessment addressed the Palo Verde experience in the section on Alloy 690 Tubing Operating Plant Experience. As a proactive response to the Palo Verde experience, the 2RE10 inspection scope was expanded to require a 20% sample MRPC examination of dents greater than 2 volts at support structures.

It should be noted that the Palo Verde dent indication was 15 volts. No similar indications were found during the STP 2RE10 examination. No similar anomalies were found in the STP dent/ding signals.

9. During the Unit 1 steam generator tube inspections, the inspections had to be terminated on several occasions due to eddy current probe and guide tube contamination from cobalt. Please clarify if you experienced similar cobalt contamination while performing inspections in the Unit 2 steam generators. In addition, please discuss the cause for the cobalt contamination.

Response:

It is suspected that the cobalt contamination during 1RE10 was due to unusually high particulate corrosion product release from the reactor core during shutdown. This material deposited in the B and C reactor coolant loops and steam generators that did not have reactor coolant pumps in operation during the cooldown. This unusually high particulate corrosion product release condition was not experienced during the 2RE10 inspection.

Figure 1

Cut Out Region