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June 27, 2003

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555

Subject: **Docket No. 50-362**
Report Of Inservice Inspection Of Steam Generator Tubes,
Cycle 12 Additional Information
San Onofre Nuclear Generating Station, Unit 3

Reference: Letter from D. E. Nunn (SCE) to Document Control Desk dated February 7, 2003, Subject: Special Report: Inservice Inspection of Steam Generator Tubes, Cycle 12

Gentlemen:

By the referenced letter, Southern California Edison (SCE) submitted the reports required by Technical Specification 5.7.2.c of the inservice inspection of steam generator tubes at San Onofre Nuclear Generating Station Unit 3. Subsequently, NRC staff requested certain additional clarifying information. The requested information is provided in the enclosure.

SCE is making no new commitments in this submittal.

If you have any questions or would like additional information concerning this subject, please contact Mr. Jack Rainsberry at (949) 368-7420.

Sincerely,

Enclosure

cc: T. P. Gwynn, Acting Regional Administrator, NRC Region IV
B. M. Pham, NRC Project Manager, San Onofre Units 2, and 3
C. C. Osterholtz, NRC Senior Resident Inspector, San Onofre Units 2 & 3

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By letter dated February 7, 2003 (ML030420183), Southern California Edison, the licensee for San Onofre Nuclear Generating Station, Unit 3, submitted a report summarizing the steam generator tube inspections performed during their 2003 outage.

In order for the staff to complete its review of this report, the following information is requested:

1. **Please discuss the scope of rotating probe inspections in the tubesheet region. For example, were the tubes inspected from 3-inches above the tubesheet to 8-inches below the top of the tubesheet.**

   Southern California Edison (SCE) Response:

   The plan for inspection below the bottom of the expansion transition was provided in a letter from SCE to the NRC dated December 12, 2002 (ADAMS Accession Number ML0235100020). In accordance with this plan, tubes were inspected over the extent of 4 inches above the hot leg tubesheet to a minimum of 7 inches below the bottom of the expansion transition.

2. **For the axial and circumferential indications found below the expansion transition, provide a summary of the size (length, depth) and location of the indications (the location should be in reference to the top of the tubesheet (TTS) or the bottom of the expansion transition, whichever is lower).**

   SCE Response:

   This information is provided in Table 1, beginning on page 8.

3. **The inspection distance in the tubesheet region is based, in part, on providing adequate resistance to tube pullout. To determine the inspection distance, testing is performed to determine the amount of resistance to pullout that a specific length of expanded tubing will provide. This testing is typically performed with non-degraded tubing. Given that degradation was found in the inspected region, discuss the effects this degradation had on the pullout resistance of these tubes.**

   That is, typical test programs for determining resistance to pullout typically do not use specimens with axial or circumferential cracks. Since degradation was found in this region at Unit 3 and most likely will be found in this region in other tubes during the next outage, discuss the effects degradation (i.e., degradation that could develop over the course of an operating cycle) has on the pullout resistance of the tube. Discuss your plans for accounting for this degradation in the development of the appropriate inspection distance for the next tube inspection outage. Please provide any data supporting your conclusion.

SCE Response:

The degradation that was found in the inspected region had no effect on the pullout resistance of affected tubes. This conclusion is based on Condition Monitoring (CM). CM includes a comparison of degradation locations and measurements (depth and length), with criteria for inspection length and criteria for structural integrity.

The CM inputs and criteria are discussed below.

A key criterion is the appropriate inspection distance for rotating probe examination of explosively expanded tubing within the tubesheet that has been developed for San Onofre steam generators. The basis of the development was work done by the Combustion Engineering Owners Group, and related work done by Westinghouse.

Circumferentially oriented cracks located in tubing within the tubesheet:

Structural integrity CM criteria are developed for tubing above the tubesheet. These criteria are for comparison with eddy current nondestructive examination measurements of an indication (length, depth, and combinations thereof, such as percent degraded Area (PDA)). These criteria were conservatively applied to indications within the tubesheet to demonstrate structural integrity. If structural integrity exists for tubing without the reinforcement of a surrounding tubesheet, it exists for tubing with the reinforcement of a surrounding tubesheet.

Axially oriented cracks located in tubing within the tubesheet:

The San Onofre Units 2 and 3 inspection distance for rotating probe examination within the tubesheet is a combination of structural integrity considerations and leakage considerations. The inspection distance needed for structural integrity considerations is less than half of that needed for leakage considerations. Thus, there is inherently significant margin available (inspection distance) for demonstrating structural integrity, when the lengths of detected axial cracks are considered (subtracted from the inspection distance).

The planned rotating probe inspection distance within the tubesheet was appropriate, when the length of Unit 3 January 2003 crack indications was considered. No additional inspection was necessary. This experience indicates that planning was sufficient in accounting for degradation that could develop over the course of the next operating cycle. Thus, no changes are indicated in development of the appropriate inspection distance for the next tube inspection outage.

Table 1 (beginning on page 8) provides data supporting the above conclusions.

4. **From Table 5 of your submittal, it appears that three tubes were in-situ pressure tested during the 2003 outage. For these indications, discuss whether any leakage was observed prior to reaching the maximum test pressure (i.e., 4800 pounds per square inch). If leakage was observed, discuss when leakage was first observed and the maximum rate observed.**

SCE Response:

These three tubes never leaked throughout the entire in-situ pressure testing process.

5. **One indication was identified in the U-bend region of a row 3 tube. Presumably, this indication resulted in the expansion of the rotating probe inspection of the U-bend region into row 4. Discuss whether any inspections (other than bobbin coil inspections) were performed in the U-bend region of higher row tubes. In addition, discuss whether any testing or analysis has been performed which indicates that the U-bend region of the lower row tubes will always exhibit degradation before the U-bend region of higher row tubes (consideration should be given to all factors that affect tube degradation including material properties and stresses).**

SCE Response:

Table 2 of the SCE Letter to the NRC dated February 7, 2003 (ADAMS Accession Number ML030420183), shows that the rotating probe inspection of the U-bend region was expanded to include 100% of the tubes in row 4, in both steam generators (not just the affected steam generator). Additionally, that Table shows that the expansion was performed with the same techniques as the planned inspection (both the mid-range frequency Plus Point Probe, and the high-range frequency Plus Point Probe).

Approximately 180 higher row bends in Steam Generator 88 and 250 higher row bends in Steam Generator 89 were inspected with a rotating Plus Point Probe during the San Onofre Unit 3 Cycle 12 refueling outage. The last three rows in Table 1 of the SCE Letter to the NRC dated February 7, 2003 illustrate some of the rotating probe examinations (dents, dings, wear indications) that contribute to the bend region of higher row tubes being inspected with a rotating Plus Point Probe, for reasons unrelated to the bend.

There is current generic consideration of testing or analysis to understand if the U-bend region of lower row tubes will always exhibit degradation before the U-bend region of higher row tubes. SCE is following this closely. While this is ongoing, SCE considers industry experience in developing inspection plans. Recent industry experience in such higher rows is an example of such experience.

6. **Please clarify the reason for plugging the tubes characterized as "miscellaneous preventative plugging." Please clarify the nature of the volumetric indication in Row 68 Column 128 in steam generator E-088.**

SCE Response:

Miscellaneous Preventative Plugging:

Two tubes were plugged because there were practical constraints in efficiently performing the desired inspection over the potential life-time of the tubes. The coincidence of a dent low in the tube, and a small U-bend radius would have resulted in excessive rotating plus point inspection because of limitations in the diameter of the bobbin probe (fill factor), and the limited available qualifications for such smaller fill factors.

One tube was plugged because pre-outage measurement of the location of the bottom of the expansion transitions indicated the tubing expansion within the cold leg tubesheet did not meet expectations (i.e., the explosive expansion is not apparent in the eddy current data).

One tube was plugged in anticipation of advances in bobbin probe noise measurement, and to help facilitate such advances.

The following information clarifies the nature of the volumetric indication in Row 68 Column 128 in steam generator E-088.

Indication Type:	Single Volumetric Indication
Initiation Locale:	on the outside diameter of the tube
Plus Point Voltage:	0.46 volts
Location:	DBH + 2.45 inches (This is 0.45 inches above the upper edge of the tube support.)
Measured Length:	0.65 inches
Measured Depth:	23% of tube wall thickness

This indication was detected by the bobbin probe. It was subsequently confirmed and characterized with a rotating probe. Historical eddy current data for this location was compared. The indication was present as early as 1993, with the following trend:

1993-1997:	little apparent change
1997-2003:	no apparent change

This indication is considered similar to other industry volumetric indication experience in large steam generators, with tubes installed within the tubesheet in a "triangular pitch" pattern.

7. Several free span indications were detected during the 2003 Unit 3 outage. Please discuss your experience with these indications. For example, has this degradation mode been observed at Unit 3 in prior outages? If so, how many tubes were affected and how severe were the indications? Discuss whether an operational assessment has been completed to address this degradation mechanism. If the degradation mechanism has not been observed in the past, discuss the basis for your assumptions concerning crack growth rates.

SCE Response:

Axially oriented cracking in the freespan of tubing was detected at San Onofre Unit 2 in 1997. In-situ pressure testing was performed on numerous indications in 10 tubes. Two tubes (with numerous indications in each tube) were removed (pulled) after supplemental eddy current testing for later comparison with destructive examination results. Laboratory testing of the two pulled tubes included burst and leak testing, and destructive examination. The information from this effort was designed to provide a basis for future CM and Operational Assessment. San Onofre Unit 2 provides significant ongoing experience for use in evaluation at both Units 2 and 3, since approximately 235 Unit 2 tubes have been affected. Specifically, these 235 affected Unit 2 tubes provide the basis for determining crack growth rates.

Similar cracking was first detected at San Onofre Unit 3 in 1997. San Onofre Unit 3 continues to be minimally affected as shown below, but benefits from Unit 2 experience (such as growth rate updating and comparison). This is a listing of the inspection dates and number of San Onofre Unit 3 tubes affected.

DATE	NUMBER OF TUBES	
May 1997	3	(Minor cracking, but in-situ pressure testing was conservatively performed because the 1997 San Onofre Unit 2 pulled tube testing and evaluation was not completed)
April 1999	1	(Minor cracking, no need for in-situ pressure or leak testing)
January 2001	0	
January 2003	5	

An Operational Assessment to address this mechanism at San Onofre Unit 3 in January 2003 is ongoing. CM was completed satisfactorily for this mechanism, without need for in-situ pressure or leak testing. This favorable CM provides a strong indicator for favorable Operational Assessment. Ongoing experience at both San Onofre Units 2 and 3 indicates that minor cracking continues to be detected and removed from service in a timely manner.

8. **Regarding the in-situ pressure testing performed at your plant for indications in the tubesheet (row 31 column 123 in steam generator E-089), discuss whether the appropriate end-cap loads were simulated during the test and provide a description of the test apparatus (including whether it was a partial or full length test; if a partial test, ensure you address the location of the sealing bladders with respect to the top of the tubesheet). The staff notes that if a full tube pressure test is performed at a pressure of 3 times the normal operating pressure it may result in simulating 3 times the axial loads; however, it also increases the contact pressure (as a result of pressure) by 3 times. In addition, such a test does not include the effect of tubesheet bow. Ideally the test should result in the more limiting of the following conditions: (a) imparting 3 times the axial loads on the tube at normal operating pressure and temperature with a hole dilation consistent with that observed during normal operation; or (b) imparting 1.4 times the axial loads on the tube at SLB differential pressures and temperature with a hole dilation consistent with that observed during a SLB. The intent of this question is to determine if the in-situ testing performed actually bounded these conditions. If the in-situ test does not provide information regarding the integrity of the indications in the tubesheet region, discuss the implications of the inspection findings and how integrity of this tube will be determined.**

In your response, discuss whether in-situ testing can be used to assess the structural and leakage integrity of tubes with flaws in the tubesheet region. Provide an analysis demonstrating the in-situ test conditions bound the conditions observed during normal operation and a steam line break (including tubesheet bow). That is, given that tubesheet bow is not simulated during an in-situ test, discuss whether the resultant contact pressure given the temperature and pressure under which the test is performed is representative of the contact pressure for which the test is designed to simulate (e.g., steam line break, 3 times the normal operating differential pressure).

SCE Response:

A full-length test was performed, thus providing simulation of appropriate end-cap loadings. This was not a partial-length test, so discussion of the location of sealing bladders is not applicable. The test resulted in imparting axial loads on the tube for the most limiting condition (3 times the normal operating differential pressure and temperature).

CM was successfully completed on this tube by eddy current testing. The in-situ pressure test was considered optional. The circumferential indication was located 0.37 inches below the region where CM is meaningful (i.e., the 7 inches of tubing below the bottom of the expansion transition).

There is a region of explosively expanded tubing within the tubesheet where structural and leakage integrity is necessary to meet associated performance criteria. This principle was key in development of an appropriate inspection distance for rotating probe examination of tubing within the tubesheet in San Onofre steam generators. The basis of this development was work done by the Combustion Engineering Owners Group, and related work done by Westinghouse.

Structural and leakage integrity CM criteria are developed for tubing above the tubesheet. These criteria are for comparison with eddy current nondestructive examination measurements of an indication (voltage, length, depth, and combinations thereof, such as percent degraded Area (PDA)). Most of these criteria (except those for axial indication structural integrity that are not applicable) were conservatively applied to indications within the tubesheet to assist in demonstrating structural and leakage integrity. If structural integrity exists for a circumferential indication in tubing without the reinforcement of a surrounding tubesheet, it exists for tubing with the reinforcement of a surrounding tubesheet. If leakage integrity exists for tubing

- without the reinforcement of a surrounding tubesheet, and
- without the explosively expanded tube/tubesheet interface leak-limiting path, then it exists for explosively expanded tubing within a tubesheet.

This is a typical process for CM of tubing within the tubesheet:

- Collect and analyze eddy current testing data
- Assemble eddy current measurements
- For axial indication structural integrity, the length(s) of detected axial crack(s) in a tube may be considered as follows: Compare the inspection distance needed for structural integrity with a calculation of inspection distance minus length(s). The inspection distance needed for structural integrity considerations is less than half of that needed for leakage considerations, thus there is significant margin available.
- Compare eddy current measurements with CM criteria for tubing above the tubesheet (except axial indication structural integrity criteria addressed in the previous step)
- CM is successfully complete if the CM criteria are met
- If CM criteria are not met, then the location of the indication is compared with the inspection distance for rotating probe examination of tubing within the tubesheet. If the indication is within this distance (where structural and leakage integrity is necessary to meet associated performance criteria), then the CM process continues. If the indication is below the inspection distance, then CM can be considered to not be meaningful.

Discussion on whether in-situ testing can be used to assess the structural and leakage integrity of tubes with flaws in the tubesheet region (with consideration of tubesheet bow) is a generic matter. SCE is following this closely.

TABLE 1
Indications At Greater Than 0.1 inches Below the Expansion Transition (BET)
San Onofre Unit 3, January 2003
Tubesheet Indications

AXIAL INDICATIONS

SG	Row	Col	Elev	Inches From	Ind	Origin	Plus Point Volts	Max Depth (%)	Length (inches)
88	32	110	BET	-1.34	MAI	ID	0.69	58	0.21
88	32	110	BET	-0.42	SAI	ID	0.38	53	0.15
88	36	66	BET	-4.95	MAI	ID	0.62	50	2.17
88	36	70	BET	-2.76	SAI	ID	0.37	53	0.12
88	36	70	BET	-2.40	SAI	ID	0.41	50	0.09
88	37	109	BET	-2.81	SAI	ID	0.57	61	0.17
88	37	109	BET	-2.21	SAI	ID	0.39	44	0.11
88	37	111	BET	-5.04	MAI	ID	0.85	51	3.70
88	49	109	BET	-0.33	SAI	ID	0.56	53	0.17
88	49	113	BET	-3.34	SAI	ID	0.41	58	0.12
88	49	113	BET	-2.30	SAI	ID	0.49	67	0.15
88	49	113	BET	-1.50	SAI	ID	0.43	58	0.12
88	53	97	BET	-2.14	SAI	ID	0.35	68	0.10
88	62	80	BET	-1.27	SAI	ID	0.19	58	0.22
88	62	80	BET	-0.99	MAI	ID	0.28	55	0.22
88	62	80	BET	-0.66	SAI	ID	0.35	66	0.16

CIRCUMFERENTIAL INDICATIONS

SG	Row	Col	Elev	Inches From	Ind	Origin	Plus Point Volts	Max Depth (%)	Length (inches)
88	8	122	BET	-8.85	SCI	ID	0.31	45	0.17
88	8	122	BET	-0.72	SCI	ID	0.23	42	0.20
88	8	122	BET	-5.47	MCI	ID	0.51	45	0.40
88	10	132	BET	-7.10	SCI	ID	0.44	65	0.17
88	10	132	BET	-6.76	SCI	ID	0.32	41	0.17
88	10	132	BET	-2.77	SCI	ID	0.30	11	0.17
88	94	138	BET	-4.97	SCI	ID	0.17	24	0.30

AXIAL INDICATIONS

SG	Row	Col	Elev	Inches From	Ind	Origin	Plus Point Volts	Max Depth (%)	Length (inches)
89	27	113	BET	-1.01	SAI	ID	0.25	46	0.11
89	31	111	BET	-3.65	SAI	ID	0.29	41	0.10

CIRCUMFERENTIAL INDICATIONS

SG	Row	Col	Elev	Inches From	Ind	Origin	Plus Point Volts	Max Depth (%)	Length (inches)
89	31	123	BET	-7.37	MCI	ID	2.08	90	0.65