June 10, 2002

MEMORANDUM TO: James W. Clifford, Chief, Section 2
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

FROM: Robert J. Fretz, Project Manager, Section 2 ***/RA/***
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NO. 2, FACSIMILE TRANSMISSION AND INFORMATION DISCUSSED IN A RECENT CONFERENCE CALL (TAC NO. MB4599)

The attached information was transmitted by facsimile on June 3, 2002, to PSEG Nuclear LLC (PSEG or the licensee). This information was provided in order to verify information members of the NRC staff had received during a recent conference call on Salem Unit No. 2 steam generators (SGs). In a phone call with the licensee on June 6, 2002, PSEG clarified that the single circumferential primary water stress corrosion cracking indication discovered at a top-of-tube sheet location should be attributed to SG 22. The NRC staff had originally assigned this indication to SG 23. PSEG added that the final inspection findings showed the following: (1) a total of 40 ligament crack indications at tube support plates, (2) 490 anti-vibration bar wear indications, and (3) 91 cold leg thinning indications.

Docket No. 50-311

Attachment: Summary of Telephone Conference Call Between Members of the U.S. Nuclear Regulatory Commission Staff and PSEG Nuclear LLC, Re: Salem Nuclear Generating Station, Unit No. 2, Steam Generator Tube Inspections

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NAME	RFretz
DATE	6/10/02

OFFICIAL RECORD COPY

LICENSEE: PSEG Nuclear LLC

FACILITY: Salem Nuclear Generating Station, Unit No. 2

SUBJECT: SUMMARY OF TELEPHONE CONFERENCE CALL BETWEEN MEMBERS OF THE U.S. NUCLEAR REGULATORY COMMISSION (NRC) STAFF AND PSEG NUCLEAR LLC, RE: SALEM NUCLEAR GENERATING STATION, UNIT NO. 2 STEAM GENERATOR TUBE INSPECTIONS (TAC NO. MB4599)

On April 19, 2002, members of the NRC staff participated in a telephone conference call with PSEG Nuclear LLC (PSEG) representatives regarding steam generator (SG) tube inspection activities at Salem Unit No. 2.

Background

Tube integrity is integral to the safe operation of SGs. Because of past problems with tubes affecting the operation of SGs, the NRC continues to support activities related to improving tube integrity, as does the nuclear industry. During November 2000, following the indian Point 2 SG leakage event, the NRC developed a Steam Generator Action Plan (SGAP) to coordinate activities related to SGs, and to ensure that issues are appropriately tracked and dispositioned. The plan consolidated numerous NRC action items related to SGs that originated from, or were associated with the following activities:

- evaluation and implementation of recommendations stemming from the NRC's Indian Point 2 Lessons Learned Task Group report
- evaluation and implementation of recommendations from NRR staff review of the Office of the Inspector General report on the IP2 steam generator tube failure event
- resolution of an NRC differing professional opinion (DPO) on steam generator issues
- the NRC's review of the industry initiative related to SG tube integrity (i.e., NEI 97-06)
- resolution of Generic Safety Issue (GSI) 163 (Multiple Steam Generator Tube Leakage)

Conference Call

The conference call was initiated by the NRC staff in accordance with SGAP Milestone 1.10. This call is usually held after licensees have inspected a majority of the tubes, but before SG inspection activities have been completed. Topics discussed during the call included:

- initial eddy current testing scope
- scope expansion plans
- indications identified to-date
- repair/plugging plans
- new inspection findings
- in-situ pressure test plans
- actions taken in response to lessons learned from the Indian Point 2 tube failure.

Attachment

Inspection Scope

PSEG stated that no primary-to-secondary leakage existed in Salem Unit No. 2 prior to shutdown. This has been the case for the past 2 to 3 cycles. Since no leakage existed, the licensee did not perform secondary side hydrostatic testing. The following table summarizes the initial inspection scope.

Description	% Inspected	Method	No. of Exams	Comments
TE to TE	100% of all in-service tubes	Bobbin		
Short Radius U-bends from the 7H TSP to the 7C TSP	100% Row 2 20% Row 3	Plus Point	420	All row 1 tubes were previously plugged
HL TTS (from 8" below TTS to 2" above TTS)	100% of all in-service tubes	Plus Point	12,684	
TS Anomalies		Plus Point	71	
HL Dents ≥ 1.0 volt (v) (as measured with Bobbin)	100% 1H and 2H 20% 3H	Plus Point	3,200 930	See Note
HL Dents ≥ 5.0 v (as measured with Bobbin)	20% 5H - 7H	Plus Point		See Note
TSP ligaments		Bobbin		low frequency screening
HL Freespan Dings ≥ 2.0 v (as measured with Bobbin)	20%	Plus Point	63	
Installed Plugs	100%	Visual		

Key:
TE = Tube end
TS = Tube sheet
TSP = Tube support plate
TTS = Top of tube sheet
C = Cold (e.g., 7C designates the no. 7 cold leg TSP)
H = Hot (e.g., 2H designates the no. 2 hot leg TSP)
CL = cold leg
HL = hot leg

Note: The licensee stated that, during refueling outage 2R9, it had inspected all dented TSPs. During the last outage, 100% of the dents ≥ 1.0 v were inspected up to and including the 4H TSP. In addition, dents located in 5H to 7H TSPs were sampled. No indications were found above the 2H TSP during this outage. These inspections and results were used as the basis for the initial inspection scope for this outage.

In-situ Pressure Testing

The licensee stated that the degradation in the SGs is mild and falls below the Condition Monitoring (CM) limits. Therefore, in-situ pressure testing was not required.

Tube Pulls

The licensee stated that a tube pull was not required for this inspection.

Inspection Findings

PSEG's inspection findings are summarized in the following table. The number of indications found for a specific degradation mechanism are shown for each SG.

Location	Degradation Mechanism	SG 21	SG 22	SG 23	SG 24	Comments
TTS	Axial Primary Water Stress Corrosion Cracking (PWSCC)	11	8	4	2	
	Circumferential PWSCC			1		See Note 1
TS	Volumetric Outside Diameter Stress Corrosion Cracking (ODSCC)			2		
TSP	Axial PWSCC		1		1	
	Circumferential PWSCC		1			Identified in 4.0 v dent in 01H TSP. First time detected at Salem Unit 2.
	Axial ODSCC	2		1		Identified in 01H TSP.
	Ligament Cracking					See Note 2
AVB	Wear	1		1		See Note 3
CL	Thinning			2	4	See Note 4
Short Radius U-bends	N/A					No flaws identified. Row 2 U-bends were heat treated in 2R5 (1990).

Notes:

1. This indication was located 2.16" below the TTS and was identified by a rotating probe containing a Plus Point (+Pt) coil. It was subsequently inspected with an RG34 probe which did not confirm the indication. However, the tube was still plugged and stabilized.

2. 28 ligament cracks were identified. None exceeded the licensee's acceptance criteria. The licensee stated that the cracks have been traced to earlier eddy current data, and they do not believe this degradation mechanism is active. This was not the first outage that ligament cracking was identified.

3. 478 AVB wear indications were identified. These indications were depth-sized, and only two required plugging.
4. 100 indications were identified. These indications were depth-sized using bobbin coil data, and only 6 required plugging. The deepest CL thinning indication was 45% through-wall. The licensee uses a plugging limit which is based on a SG-specific 95th percentile growth rate. The plugging limits used by the licensee ranged from 35% through-wall to 40% through-wall (the technical specification limit). The licensee

periodically inspects CL thinning indications with a rotating probe to confirm the degradation mechanism.

The licensee determined that the amount of degradation has decreased from the previous SG inspection. PSEG believes this may be due to the most susceptible tubes having been plugged during previous outages.

Plugged Tubes

The following table summarizes the total tubes plugged per SG during this outage.

SG	Total Tubes Plugged
21	14
22	8
23	10
24	9

TELEPHONE CONFERENCE PARTICIPANTS
SALEM NUCLEAR GENERATING STATION, UNIT NO. 2
STEAM GENERATOR TUBE INSPECTIONS
April 19, 2002

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