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SOUTHERN COMPANY
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December 7, 1999

Docket No.: 50-364

NEL-99-0435

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

Joseph M. Farley Nuclear Plant - Unit 2
Licensee Event Report 99-002-00
Steam Generator Tube Degradation and Tube Status

Ladies and Gentlemen:

Joseph M. Farley Nuclear Plant - Unit 2 Licensee Event Report No. 99-002-00 is being submitted in accordance with Technical Specification 4.4.6.5.c. There are no NRC commitments in the Licensee Event Report.

If you have any questions, please advise.

Respectfully submitted,

DM Morey

Dave Morey

DWD/maf: 99-002-00.doc
Attachment

IE22

PDR ADOCK 05000364

cc: Southern Nuclear Operating Company
Mr. L. M. Stinson, General Manager – Farley

U. S. Nuclear Regulatory Commission, Washington, D. C.
Mr. L. M. Padovan, Licensing Project Manager – Farley

U. S. Nuclear Regulatory Commission, Region II
Mr. L. A. Reyes, Regional Administrator
Mr. T. P. Johnson, Senior Resident Inspector – Farley

NRC FORM 366 (6-1998)

U.S.NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104 EXPIRES: 06/30/2001

Estimated burden per response to comply with this mandatory information request: 50 hrs. Reported lessons learned are incorporated into the licensing process and fed back to industry. Forward comments regarding burden estimate to the Records Management Branch (T-6 F33), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, and to the Paperwork Reduction Project (3150-0104), Office of Management and Budget, Washington, DC 20503. If an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

LICENSEE EVENT REPORT (LER)

(See reverse for required number of digits/characters for each block)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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TITLE (4)

Steam Generator Tube Degradation and Tube Status

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAME	DOCKET NUMBER
11	01	1999	1999	002	00	12	07	1999		
									FACILITY NAME	

OPERATING MODE (9): N

POWER LEVEL (10): 000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.2201(b)		20.2203(a)(2)(v)		50.73(a)(2)(i)		50.73(a)(2)(viii)
	20.2203(a)(1)		20.2203(a)(3)(i)	X	50.73(a)(2)(ii)		50.73(a)(2)(x)
	20.2203(a)(2)(i)		20.2033(a)(3)(ii)		50.73(a)(2)(iii)		73.71
	20.2203(a)(2)(ii)		20.2033(a)(4)		50.73(a)(2)(iv)	X	OTHER
	20.2203(a)(2)(iii)		50.36(c)(1)		50.73(a)(2)(v)		*Specify in Abstract below*
	20.2203(a)(2)(iv)		50.36(c)(2)		50.73(a)(2)(vii)		*or in NRC Form 366A*

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include area code)
L. M. Stinson, General Manager Nuclear Plant	334-899-5156

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO EPIX

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-space typewritten lines) (16)

On November 1, 1999, Farley Nuclear Plant steam generator inspection results were classified as Category C-3 in accordance with Technical Specification 4.4.6.2 and are being reported in accordance with Technical Specification 4.4.6.5.c. A voluntary notification report to the NRC of the C-3 inspection classification was made on November 1, 1999.

Eddy current inspections were performed on one hundred percent of the available tubes in all three steam generators (S/G's). As a result of this inspection, more than 1% of the inservice tubes during Cycle Thirteen in all three S/G's were found to be defective, which requires inspection results in the S/G's to be classified as Category C-3. Defective indications were identified within the tubesheet, above the top of the tubesheet in the sludge pile area, in the free span, and at the tube support plates. In addition to the required tube plugging, several ongoing programs have been established to reduce the probability of future tube degradation. The S/G's are scheduled to be replaced during the next refueling, U2RF14.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL YEAR	REVISION NUMBER	
Joseph M. Farley Nuclear Plant - Unit 2	0 5 0 0 0 3 6 4	1999	0 0 2 -	0 0	2 OF 7

TEXT (If more space is required, use additional NRC Form 366) (17)

Plant and System Identification

Westinghouse - Pressurized Water Reactor.

Energy Industry Identification System codes are identified in the text as [XX].

Description of Event

This report is being submitted in accordance with Technical Specification 4.4.6.5.c to report Category C-3 S/G tube inspection results, and corrective measures taken to prevent recurrence.

The results of the S/G inspections were determined to be category C-3 on November 1, 1999. The S/G tube plugging was completed on November 13, 1999.

Prior to the U2RF13 outage, Southern Nuclear developed an inspection plan to inspect tubes in all three S/G's. The inspection plan included:

- One hundred percent full length bobbin probe inspection of all available tubes with the exception of row 1 and row 2 U-bends.
- One hundred percent plus point probe inspection of all available hot leg roll transitions.
- 20% plus point inspection of all available cold leg roll transitions in S/G's 2A and 2B.
- 100% plus point inspection of all available cold leg roll transitions in S/G 2C.
- Plus point inspection of all available row 1 and row 2 U-bends.
- Plus point inspection of all sludge pile and freespan indications identified by bobbin.
- Plus point inspection of all free span sleeve ends.
- Cecco probe inspection of all sleeves.
- Tube support plate (TSP) plus point inspection program required by the TSP alternate repair criteria (ARC).
- Visual inspection of all plugs.
- In situ testing as necessary to support condition monitoring and operational assessment evaluations.

The TSP ARC program of plus point inspections was performed on the following bobbin signals: all support plate indications greater than 2.0 volts, all dents greater than 5.0 volts, all large support plate residual signals, and all TSPs with interfering signals from copper deposits.

During the TSP plus point inspection program in S/G 2C of TSP residual signals, free span axial indications by plus point were identified just outside the TSP. These indications were not detectable by bobbin. Since the possibility existed that the indications were masked by the residual signals, the inspection program was expanded to include the next 66 largest voltage TSP residuals in S/G 2C. During the expansion program, two additional defects were identified outside TSP intersections. The program was expanded to the 132 next highest voltage mixed residuals. This second expansion was planned with the goal of defining a critical area and buffer zone for freespan indications at TSP edges potentially masked for bobbin detection by mixed residuals. One additional freespan indication was identified during this expansion. The inspection results satisfied the critical area and buffer zone criteria for all three S/G's and no further expansion was required.

In situ leak testing was performed on 4 indications in S/G 2B and 1 indication in S/G 2C. No leakage was observed. Two of the four indications in S/G 2B were in situ pressure tested and satisfactorily passed the pressure test.

DEGRADATION ASSESSMENT

During U2RF12, the degradation assessment concluded that the following active degradation mechanisms (as defined by EPRI TR-107569-V1R5) were present in the Unit 2 S/G's:

- Axial ODSCC (outer diameter stress corrosion cracking) at hot leg TSP intersections.
- Axial ODSCC at the hot leg TTS (top of tubesheet) expansion transition.
- Axial PWSCC (primary water stress corrosion cracking) at the hot leg TTS expansion transition.
- Axial PWSCC at the cold leg TTS expansion transition in S/G 2C.
- Circumferential PWSCC at the hot leg TTS expansion transition.
- Circumferential ODSCC at the hot leg TTS expansion transition.
- Axial ODSCC in the hot leg sludge pile.

As a result of the inspections performed during U2RF13, free span axial ODSCC was also identified as an active degradation mechanism.

ECT Tube Plugging Attributes	A	B	C
Inservice tubes prior to RF	3119	3193	3181
Circumferential ODSCC at expansion down to F*	56	73	54
Axial ODSCC at the TTS expansion down to F*	4	5	9
Above the tubesheet ODSCC	0	1	5
Circumferential PWSCC at the TTS expansion down to F*	2	2	2
Axial PWSCC at the TTS expansion down to F*	36	13	35
Freespan ODSCC	0	4	9
Sleeve end, (administrative)	0	1	0
TSP ODSCC	2	0	12
Total tubes plugged	100	99	126

Rankings are used to prioritize multiple indications observed on a single tube, any of which viewed alone would require repair of the tube; in effect a single indication is chosen for each tube as representing the attributed cause for plugging that specific tube.

Tube repair summary	A	B	C
Inservice Tubes prior to RF	3119	3193	3181
Tubes plugged during RF	100	99	126
Repair actions during RF	--	--	--
TSP sleeves installed during RF and left in service	0	0	0
30" TS sleeves installed during RF and left in service	0	0	0
20" TS sleeves installed during RF and left in service	0	0	0
12" TS sleeves installed during RF and left in service	0	0	0

Tube status	A	B	C
Tubes inservice prior to RF	3119	3193	3181
Sleeves in service prior to RF	575	236	479
Sleeved tubes in service prior to RF	538	233	440
Percent plugging equivalent prior to RF	8.9	6.2	6.9
Tubes returned to service during RF	0	0	0
Total in service sleeves after RF	574	235	474
Total in service sleeved tubes after RF	537	232	435
Total plugged tubes after RF	369	294	333
Plugging equivalent of sleeves	33	13	25
Percent plugging equivalent after RF	11.9	9.1	10.6

The overall average percent plugging equivalent before U2RF13 of 7.3% was increased to 10.5% after U2RF13.

CONDITION MONITORING EVALUATION SUMMARY

Based on the U2RF13 inspections results, no tubes contained indications which represented a challenge to structural or leakage integrity and all condition monitoring requirements are satisfied.

OPERATIONAL ASSESSMENT EVALUATION SUMMARY

Based on the inspection results and growth rates found during the U2RF13 inspection, all operational assessment structural and leakage integrity requirements are expected to be satisfied at End of Cycle (EOC)-14 for the degradation mechanisms observed at EOC-13.

<u>Cause of Event</u>

Investigations and evaluations performed identified several areas where tube defects were observed. These were: tube sheet and expansion transition degradation, free span, and tube support plate.

<u>Reportability Analysis and Safety Assessment</u>

This event is being reported in accordance with Technical Specification 4.4.6.5.c. A condition monitoring and operational assessment has been completed addressing the safety significance of Cycle 13 and Cycle 14 operation of Farley Unit 2 with the various types of localized tube wall degradation occurring in the steam generator tubing. Steam generator 2C was found to be the limiting SG for Cycle 13 operation and is projected to be the limiting steam generator for Cycle 14 operation. Calculations show that the voltage based repair criteria at end of Cycle 14 will satisfy the NRC criteria for allowable leakage and burst capability. It is concluded that Cycle 14 operation of Farley Unit 2 will continue to meet the required acceptance criteria. A more complete data review and evaluation will be performed to finalize the operational assessment; however, the conclusions of the preliminary assessment are not expected to change.

Since this LER does not report any structural tube failures, it does not represent a Safety System Functional Failure.

Corrective Action

The S/G tubes have been plugged as required. In addition, the following actions are continuing in order to reduce the probability of future tube degradation:

1. A program of secondary side boric acid addition which was begun in 1983 is being continued to reduce the potential for ODSCC.

2. Several secondary side chemical addition programs have been initiated to reduce the potential for sludge accumulation. A program of morpholine addition was begun in 1988. Hydrazine addition to the feedwater system was increased in 1993. Monoethanolamine (ETA) addition was started in 1993.

3. A program of molar ratio control was begun in late 1994 to reduce the potential for corrosion in the crevice region of the tube support plates.

4. The Westinghouse sludge lance cleaning process was initiated during the First Refueling in all three S/G's to remove contaminants from the top of the tubesheet area. (Not performed this refueling)

5. The Westinghouse pressure pulse cleaning program was initiated during the Eighth Refueling in all three S/G's to remove contaminants from the crevices between the tubes and support plates. (Not performed this refueling)

6. The Westinghouse U-bend heat treat process was performed on all Row 1 and 2 tubes in service during Seventh Refueling Outage to reduce the potential of U-bend SCC.

7. During the Unit 2 Second, Third and Fourth Refueling Outages, many of the secondary side components containing copper were replaced with components containing stainless steel.

8. The Unit 2 S/G's are scheduled to be replaced at the end of Cycle 14.

Additional Information

During the previous two years, S/G tube integrity conditions were reported in LERs 97-006-00 (Unit 1), 98-003-00 (Unit 2), 98-002-00 (Unit 1), and 1998-007-00 (Unit 1).

On November 1, 1999, Southern Nuclear (SNC) made a voluntary notification of the C-3 inspection classification.

Due to the detection of free span axial ODSCC on Unit 2 during U2RF13, FNP has elected to administratively lower the primary to secondary leakage limit as follows:

- Plant to be shutdown within 24 hours following a leak rate spike confirmed by chemistry samples to exceed 75 gpd.
- Plant to be shutdown if the leak rate following a spike above 60 gpd does not decrease to less than 60 gpd following the leak rate spike. Successive leakage spikes above 60 gpd, but less than 75 gpd, within a seven day span do not require shutdown since the 60 gpd limit is intended to be a longer term leak rate without spikes.
- Plant to be shutdown within 24 hours following a progressive (with spikes) increase in the leak rate to greater than 60 gpd confirmed by chemistry samples.

The above operating leak rate limits are to be administratively implemented for Cycle 14 operation only. The S/G's are to be replaced following Cycle 14 operation.