VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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United States Nuclear Regulatory Commission
Attention: Document Control Desk
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VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT
FOR THE FALL 2016 REFUELING OUTAGE

Technical Specification 6.6.A.3 for Surry Power Station Units 1 and 2 requires the submittal of a Steam Generator Tube Inspection Report to the NRC within 180 days after T_{avg} exceeds 200°F following completion of an inspection performed in accordance with Technical Specification 6.4.Q, Steam Generator Program. Attached is the Surry Unit 1 report for the Fall 2016 refueling outage.

If you have any questions concerning this information, please contact Mrs. Candee G. Lovett at (757) 365-2178.

Very truly yours,

Fred Mladen
Site Vice President
Surry Power Station

A047
NRR

Attachment: Surry Unit 1 Steam Generator Tube Inspection Report for the Fall 2016 Refueling Outage

Commitments made in this letter: None

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ATTACHMENT

SURRY UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT
FOR THE FALL 2016 REFUELING OUTAGE

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)

SURRY UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT
FOR THE FALL 2016 REFUELING OUTAGE

The following satisfies the Surry Power Station Technical Specification (TS) reporting requirement Section 6.6.A.3. During the Surry Unit 1 Fall 2016 End-Of-Cycle 27 (EOC27) refueling outage, Steam Generator (SG) inspections in accordance with TS 6.4.Q were completed for SG B.

The Unit 1 SGs are in the 4th inspection period, which has a duration of 72 Effective Full Power Months (EFPM). The Fall 2016 refueling outage was the third outage of the 4th period.

Unit 1 exceeded 200°F on November 8, 2016; therefore, this report is required to be submitted by May 5, 2017. At the time of this inspection, the Unit 1 SGs had operated for 334 EFPM since the first inservice inspection.

In the discussion below ***bold italicized*** wording represents TS verbiage and the required information is provided directly below each reporting requirement. A list of acronyms is provided at the end of this report.

A report shall be submitted within 180 days after Tavg exceeds 200°F following completion of an inspection performed in accordance with the Specification 6.4.Q, "Steam Generator (SG) Program." The report shall include:

a. The scope of inspections performed on each SG,

Primary Side

During the Unit 1 EOC27 refueling outage, primary side inspections were performed in SG B only. The eddy current inspections included the following:

- Bobbin inspection of all in-service tubing except the U-bends of Rows 1 and 2 and the U-bend of Tube R3 C20,
- Motorized Rotating Pancake Coil (MRPC) inspections of the U-bends of Rows 1 and 2 and Tube R3 C20,
- Array inspection of all in-service tubes from TSH -17.89" to the lowermost hot leg support structure (either BPH or 01H),
- Array inspection of all in-service tubes from TSC -17.89" to the lowermost cold leg support structure (either BPC or 01C),
- Array inspection of hot leg straight sections of all in-service tubes with high residual stress, and
- MRPC inspections of locations of special interest based on bobbin and array inspection results.

Note that Tube R3 C20 has a historical restriction above the 07C support plate. The U-bend of this tube was inspected with an MRPC probe in lieu of a bobbin probe.

As-found and as-left visual examinations were performed in the primary side channel head in SG B. No degradation or other anomalous conditions associated with the divider plate, welds, cladding, channel head, channel head drain, or previously installed plugs were observed. Examination of the bottom of the bowl and drain in the dry condition showed no degradation.

Secondary Side

Secondary side inspections were performed in SG B only.

A visual inspection of the upper steam drum moisture separator components, feedring components, and top of bundle U-bend region components through the secondary manway was performed. This inspection was performed for all accessible steam drum components and structures, including the feedring exterior, the upper tube bundle, and 7th tube support plate (TSP) by probe insertions through the primary moisture separators. No degradation or adverse conditions were noted during these inspections. Sludge lancing was also performed in SG B. Foreign Object Search and Retrieval (FOSAR) examinations were performed at the top of the tubesheet, in the annulus, and the no-tube lane, as required.

b. Degradation mechanisms found,

Degradation mechanisms targeted by the inspection plan included anti-vibration bar (AVB) wear, pitting, foreign object wear, tube support wear, and stress corrosion cracking (SCC) at various locations within the SG tube bundle. AVB wear, TSP wear, baffle plate wear, and foreign object wear were detected. No pitting or SCC was detected.

c. Nondestructive examination techniques utilized for each degradation mechanism,

The inspection program focused on the degradation mechanisms listed in Table 1 and utilized the referenced eddy current techniques.

Table 1– Inspection Method for Applicable Degradation Modes

Classification	Degradation Mechanism	Location	Probe Type
Existing	Tube Wear	Anti-Vibration Bars	Bobbin – Detection and Sizing
Existing	OD Pitting	Top-of-Tubesheet (TTS)	Bobbin and +Point™ – Detection +Point™ - Sizing
Existing	Tube Wear	Tube Support Plate	Bobbin – Detection +Point™ – Sizing
Existing	Tube Wear (foreign objects)	Freespan and TTS	Bobbin and +Point™ – Detection +Point™ - Sizing
Potential	ODSCC PWSCC	Hot Leg TTS	+Point™ – Detection and Sizing
Potential	PWSCC	Tube Ends	N/A*
Potential	Tube Wear	Flow Distribution Baffle	Bobbin – Detection +Point™ – Sizing
Potential	ODSCC PWSCC	Bulges, Dents, Manufacturing Anomalies, and Above-Tubesheet Over Expansions (OVRs)	+Point™ – Detection and Sizing
Potential	ODSCC	Tubesheet Crevice in Tubes With No Tube Expansions (NTEs)	+Point™ – Detection and Sizing
Potential	Tube Slippage	Within Tubesheet	Bobbin Detection
Potential	PWSCC	Tubesheet Over Expansions (OXPs)	+Point™ – Detection and Sizing
Potential	ODSCC PWSCC	Row 1 and 2 U-bends	+Point™ – Detection and Sizing
Potential	ODSCC	Freespan and Tube Supports	Bobbin – Detection +Point™ - Sizing

*Inspection not required per technical specification alternate repair criteria.

d. ***Location, orientation (if linear), and measured sizes (if available) of service induced indications,***

As stated in the (b) response above, service induced indications were identified. Tables 2 and 3 provide the required information.

Table 2: Surry 1 Fall 2016 Inspection Summary – AVB Indications

SG	Row	Col	AVB No.	Depth (%TW) ETSS 96041.1	
				2013	2016
SGB	22	72	AV3	13	13
SGB	26	61	AV3	15	13
SGB	28	66	AV2	11	13
SGB	31	33	AV2	14	17
SGB	32	26	AV3	8	11
SGB	34	58	AV2	24	24
SGB	34	58	AV3	19	20
SGB	34	79	AV3	10	12
SGB	35	17	AV1	13	9
SGB	35	17	AV2	11	11
SGB	35	17	AV3	22	24
SGB	36	33	AV3	10	8
SGB	36	65	AV4	11	11
SGB	38	22	AV2	11	12
SGB	38	22	AV3	NR	12
SGB	38	25	AV3	NR	10
SGB	39	24	AV3	NR	13
SGB	39	29	AV2	NR	10
SGB	39	36	AV3	6	10
SGB	39	66	AV1	11	9
SGB	40	25	AV2	16	21
SGB	40	26	AV2	9	12
SGB	41	27	AV2	13	12
SGB	41	27	AV3	13	11
SGB	41	47	AV2	NR	10
SGB	42	29	AV2	15	16
SGB	42	30	AV2	14	13
SGB	42	30	AV3	10	11
SGB	43	32	AV2	13	14
SGB	43	34	AV3	6	13
SGB	45	37	AV2	NR	11
SGB	45	37	AV3	NR	11
SGB	45	38	AV2	NR	11
SGB	46	45	AV2	20	16

NR = Not Reported during the previous outage

Table 3: Summary of Non-AVB-Wear Volumetric Degradation

SG	Row	Col	Location	ETSS	Max Depth (%TW)	Axial Length (in)	Circ Length (in)	Initially Reported	Signal Present Prior to Current Outage?	Cause	Foreign Object Remaining?	In Situ Tested?	Plugged & Stabilized?
SGB	1	7	TSH +0.27"	21998.1	21% TW	0.65"	0.37"	2007	Yes. No change since initially reported.	Historical SG Maintenance	N/A	No	No
SGB	31	15	BPH +0.50"	27901.1	19% TW	0.24"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	31	16	BPH +0.50"	27901.1	25% TW	0.24"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	32	15	BPH +0.53"	27901.1	18% TW	0.24"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	32	18	BPH +0.53"	27901.1	18% TW	0.29"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	33	18	BPH +0.53"	27901.1	19% TW	0.18"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	35	20	BPH +1.09"	27902.1	16% TW	0.66"	0.38"	2010	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	37	31	03H +26.69"	21998.1	15% TW	0.24"	0.32"	2013	Yes. Indication present in 1994, but not reported until array exam in 2013	Small volumetric with no change since 1994	N/A	No	No
SGB	40	50	TSH +0.27"	27901.1	33% TW	0.34"	0.43"	2007	Yes. No change since initially reported.	Foreign Object	No	No	No

SG	Row	Col	Location	ETSS	Max Depth (%TW)	Axial Length (in)	Circ Length (in)	Initially Reported	Signal Present Prior to Current Outage?	Cause	Foreign Object Remaining?	In Situ Tested?	Plugged & Stabilized?
SGB	40	51	TSH +0.33"	27901.1	33% TW	0.35"	0.43"	2007	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	41	51	TSH +0.12"	27901.1	23% TW	0.24"	0.38"	2007	Yes. No change since initially reported.	Foreign Object	No	No	No
SGB	45	48	TSC +2.80"	21998.1	31% TW	0.29"	0.38"	2013	Yes. Indication present in 1992 and reported as NQH since 1994, but not reported as VOL until array exam in 2013	Small volumetric with no change since 1994	N/A	No	No

e. *Number of tubes plugged during the inspection outage for each degradation mechanism,*

No tubes required plugging as a result of SG inspections performed during the EOC27 outage.

f. *The number and percentage of tubes plugged to date, and the effective plugging percentage in each steam generator.*

Table 4 provides the plugging totals and percentages to date.

Table 4 – Tube Plugging Summary

	Tubes Installed	Tubes Plugged To-Date
SG A	3,342	44 (1.3%)
SG B	3,342	26 (0.8%)
SG C	3,342	41 (1.2%)
Total	10,026	111 (1.1%)

g. *The results of condition monitoring, including the results of tube pulls and in-situ testing,*

All degradation identified during the Fall 2016 inspection satisfied condition monitoring requirements for SG tube structural and leakage integrity. Further, the results from the current outage inspection validate prior outage operational assessment assumptions. Therefore, tube pulls and in-situ pressure testing were not necessary.

h. *The primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG) during the cycle preceding the inspection which is the subject of the report,*

Routine primary-to-secondary leak monitoring is conducted in accordance with station procedures. During the cycle preceding EOC27, no measurable primary-to-secondary leakage (i.e., >1 GPD) was observed in any Unit 1 SG.

i. ***The calculated accident induced LEAKAGE rate from the portion of the tubes below 17.89 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced LEAKAGE rate from the most limiting accident is less than 1.80 times the maximum operational primary to secondary LEAKAGE rate, the report should describe how it was determined,***

The permanent alternate repair criteria (PARC) requires that the component of operational leakage from the prior cycle from below the H-star distance be multiplied by a factor of 1.8 and added to the total accident leakage from any other source, and compared to the allowable accident induced leakage limit. Since there is reasonable assurance that no tube degradation identified during this outage would have resulted in leakage during an accident, the contribution to accident leakage from other sources is zero. Assuming that the prior cycle operational leakage of <1 GPD originated from below the H-star distance, and multiplying this leakage by a factor of 1.8 as required by the PARC, yields an accident induced leakage value of <1.8 GPD. This value is well below the 470 GPD limit for the limiting SG and provides reasonable assurance that the accident induced leakage performance criteria would not have been exceeded during a limiting design basis accident.

j. ***The results of the monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.***

No indications of tube slippage were identified during the evaluation of bobbin probe examination data from SG B. Note that no bobbin probe examinations were performed in SG A and SG C during EOC27. All tubes in SG A and SG C were screened for slippage during EOC26 (no indications were identified) and will again be screened during EOC28.

Acronyms

AVB	Anti-Vibration Bar
BPC	Baffle Plate Cold
BPH	Baffle Plate Hot
EFPM	Effective Full Power Months
EOC	End of Cycle
FOSAR	Foreign Object Search and Retrieval
GPD	Gallons per Day
MRPC	Motorized Rotating Pancake Coil
NQH	Non Quantifiable History
NTE	No Tube Expansion
OD	Outer Diameter
ODSCC	Outer Diameter Stress Corrosion Cracking
PARC	Permanent Alternate Repair Criteria
OVR	Over Roll
OXP	Over Expansion
PWSCC	Primary Water Stress Corrosion Cracking
SCC	Stress Corrosion Cracking
SG	Steam Generator
TSC	Tube Sheet Cold
TSH	Tube Sheet Hot
TSP	Tube Support Plate
TTS	Top of Tubesheet
VOL	Volumetric