VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

May 21, 2008

Attention: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555-0001

Serial No.	08-0272
SS&L/TJN	R1
Docket No.	50-280
License No.	DPR-32

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 1
STEAM GENERATOR TUBE INSERVICE INSPECTION REPORT FOR THE 2007 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 Tavg exceeds 200°F following completion of an inspection performed in accordance with the Technical Specification 6.4.Q, Steam Generator Program. Attached is the Surry Power Station Unit 1 report for the 2007 refueling outage.

If you have any questions or require additional information, please contact Mr. Gary D. Miller at 804-273-2771.

Sincerely,

D. E. Jernigan
Site Vice President
Surry Power Station

Attachment

Commitments made in this letter: None

A047
NRR

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Docket No.: 50-280

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ATTACHMENT 1

SURRY UNIT 1
180-DAY NRC REPORT REGARDING STEAM GENERATOR TUBE INSPECTION PER TECHNICAL SPECIFICATION 6.6.A.3

SURRY POWER STATION UNIT 1
VIRGINIA ELECTRIC AND POWER COMPANY

SURRY UNIT 1 – FALL 2007

The following satisfies the Surry Power Station Technical Specification (TS) reporting requirement section 6.6.A.3. Bold-italicized wording below represents TS 6.6.A.3 verbiage. The required information is provided below under each reporting requirement.

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."

During the Surry fall 2007 refueling outage, steam generator inspections in accordance with TS 6.4.Q were completed for one of the three steam generators ("B"). This was the initial inspection under the modified Technical Specifications resulting from the TSTF-449 generic specification issued to the industry. Consequently, the referenced outage is the starting point for compliance to the periodicity and tube inspection coverage requirements of TS 6.4.Q

Surry Unit 1 Tavg exceeded 200°F on November 28, 2007, therefore 180 days after Tavg exceeded 200°F is May 26, 2008. Effective Full Power Months (EFPM) were 234.4.

The report shall include:

a. The scope of inspections performed on each SG

The following primary side inspections were performed in steam generator "B" (SG- B)

- 100% bobbin probe exam [3048 tubes full Length; 273 tubes straight only in rows 1 through 3 hot leg (H/L) and cold leg (C/L); 188 tubes (u-bends only) rows 2 and 3]
- 669 tubes (20%) +Point probe exam of top of tubesheet H/L [+3"/-3"]
- 669 tubes (20%) +Point probe exam of top of tubesheet C/L [+3"/-3"]
- +Point probe exam of row 1 u-bends [85 tubes from 7C to 7H]
- Miscellaneous +Point probe exams: confirmation/characterization of bobbin indications (non-quantifiable indications, etc) per Dominion Analysis Guidelines; 20% sample of dent related indications; 50% sample of hot leg over expansions (OXPs); largest cold leg OXPs; other special interest locations. From the OXP through the tube end, including the last 4 inches of the tube on the hot leg, 199 tube ends were inspected, and 11 of these tests were performed on the cold leg.
- Tubesheet and plug video scan: video examinations of the hot and cold channel head bowls and tubesheets were performed after removal of the diaphragms. Plugs in each leg of this SG were examined visually and revealed no evidence of leakage. No cladding damage or tube end damage was observed and no foreign objects were identified.

The following secondary side flushing, lancing and examinations were conducted:

- Upper Bundle Flush (SG- A, B, C)

The bulk of the deposit inventory in these steam generators is known to be located above the top of tubesheet on tubes, supports surfaces, in separators, and on other internal surfaces. In an attempt to reduce the deposit inventory, the upper bundle flush (UBF) process was applied to all three SGs during the outage.

- Flow Distribution Baffle Sludge Lancing (SG- A, B, C)

Following the application of the UBF process, the top surface of the flow distribution baffle (FDB) was cleaned using a 3000 psi, high flow rate static lance. This was the first application of the high pressure, high flow process at Surry. Lancing of the FDB washes deposit material accumulated during UBF down to the tubesheet secondary face where it can be removed by another static lancing application.

- Top of Tubesheet (TTS) Sludge Lancing (SG- A, B, C)

Top of tubesheet water lancing was performed in all three steam generators using the high pressure, high flow process. The end of cycle (EOC) 21 quantity of sludge removed from each SG is summarized in attached Table 1.

- Top of Tubesheet Cleanliness and FOSAR Examinations (SG- A, B, C)

Post sludge lancing foreign object search and retrieval (FOSAR) examinations were performed in each SG at the top of the tubesheet in the annulus and no-tube lane.

- In-bundle Visual Examinations (SG- A, B, C)

In-bundle visual examinations were also performed in all three SG's to evaluate the effectiveness of the high pressure, high flow lancing process and to determine if the di-methylamine (DMA) soak during shut down helped reduce deposits on the tubesheet. Although some hard deposits still remain in all three SG's, a significant reduction of the tube collars and the bridging deposits was observed, particularly in SG- A and SG- C.

- Ultrasonic Examination of Feedring (SG- A, B, C)

Selected portions of the feedring for all three steam generators were inspected using ultrasonic examination to allow for continued trending of pipe wall thickness. The data was evaluated and concluded that no condition is expected to develop prior to the next examination which could impair SG tube integrity.

b. Active degradation mechanisms found

No indication of corrosion degradation was observed during this inspection. Only shallow mechanical damage was reported in four tubes with volumetric degradation above the top of tubesheet on the hot side (attached Table 4), and ten tubes with anti-vibration bar (AVB) wear (attached Table 3).

Of the four tubes identified in attached Table 4, three are adjacent to each other and their damage is attributed to historical foreign object wear (no object was immediately adjacent to these tubes during this inspection). Two of the three indications were detectable in 1998 and have not changed since that time. The third indication could not be detected with the technique used in 1998 but was likely caused by the same foreign object. The fourth indication (Row 1 Col 7) is attributed to a previous SG maintenance process such as sludge lancing or secondary side inspection. No foreign objects remain adjacent to any of the affected tubes and none of the indications exceeded the Technical Specification plugging limit.

The largest AVB wear flaw identified during this examination was only 22 % through-wall (TW). Two shallow AVB wear indications reported during this inspection were not reported during the previous inspection. Historical data reviews confirmed that the indications were present previously, but were below the reporting criteria, hence they are not new flaws. The growth rate of AVB wear continues to decline and no newly initiated AVB wear was identified. No tubes required plugging due to AVB wear during this outage.

The secondary side inspections indicated no component degradation that would compromise tube integrity.

c. Nondestructive examination techniques utilized for each degradation mechanism

Inspections focused on the degradation mechanisms listed in attached Table 2 utilizing the referenced eddy current techniques.

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

As stated in the (b) response above, several wear type indications were noted. Attached Tables 3 and 4 provide the detailed information regarding these indications.

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

A number of tubes were found to contain permeability variation (PVN) signals. PVN signals are important because they can interfere with degradation signals. The PVNs were re-examined with +Point probes and in some cases with magnetically biased +Point probes to suppress the signal and allow the underlying tube material to be properly examined. No degradation was identified. In one tube however, the PVN signal could not be adequately suppressed to ensure a high quality inspection and the tube was preventively plugged. Attached Table 5 provides the detailed information regarding the tube which was plugged.

f. Total number and percentage of tubes plugged to date

Attached Tables 6 and 7 provide the plugging attributes and the percentage of tubes plugged to date.

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

The Condition Monitoring evaluation was based upon fall 2007 examination results for SG- B. All reported degradation falls below the applicable condition monitoring limit (i.e. 66.4% for bounding 0.6" long 360 degree volumetric degradation) and therefore satisfies the Technical Specification structural performance criteria. This provides reasonable assurance that none of these volumetric flaws would have leaked during a main steam line break, thereby satisfying the accident leakage performance criteria. Since this conclusion could be reached analytically using NDE inspection results with a full accounting of significant uncertainties, no in-situ pressure testing was required to demonstrate structural and leakage integrity. During the past operating cycle, no measurable primary-to-secondary leakage was observed, thereby satisfying the operational leakage performance criteria.

The results of the 2007 inspection and the condition monitoring conclusions confirm that the 2006 operational assessment was appropriately bounding. No tubes were removed from the SG for destructive examination.

h. The effective plugging percentage for all plugging in each SG

There are no sleeves installed in the Surry Unit 1 steam generators therefore, the effective plugging percentage remains the same as stated in (f) above.

Table 1- Sludge Removal Summary EOC 21

Steam Generator	Quantity Removed (lbs)
A	55.5
B	53.5
C	101.5

Table 2 – Inspection Method for Applicable Degradation Modes

Classification	Degradation Mechanism	Location	Probe Type
Potential	Tube Wear	Anti-Vibration Bars	Bobbin – Detection Bobbin and +Point™ – Sizing
Potential	Tube Wear	Flow Distribution Baffle	Bobbin – Detection Bobbin and +Point™ – Sizing
Existing	Tube Wear	Tube Support Plate	Bobbin – Detection Bobbin and +Point™ – Sizing
Potential	Tube Wear	Straight Leg & AVB Tangents	Bobbin – Detection Bobbin or +Point™ – Sizing
Existing	Tube Wear (foreign objects)	Freespan and TTS	Bobbin – Detection +Point™ - Sizing
Potential	ODSCC	Hot Leg Top-of-Tubesheet Sludge Pile Area	Bobbin and +Point™ – Detection +Point™ - Sizing
Relevant/Informational Inspection	PWSCC	Hot Leg Top-of-Tubesheet Sludge Pile Area and Within Tubesheet Anomaly locations	+Point™ – Detection and Sizing
Relevant/Informational Inspection	ODSCC PWSCC	Row 1 U-bends	+Point™ – Detection and Sizing
Relevant/Informational Inspection	ODSCC	Freespan and Tube Supports	+Point™ – Detection and Sizing
Relevant/Informational Inspection	OD Pitting	Top-of-Tubesheet	Bobbin and +Point™ – Detection +Point™ - Sizing

ODSCC- outside diameter stress corrosion cracking
PWSCC- primary water stress corrosion cracking

Table 3– Surry 2007 Inspection Summary – AVB Indication

Comparison of 2003 and 2007 AVB Wear Depths - Surry Unit 1 - SG B									
				Location (inch)		Depth (%TW) (ETSS 96004.1)		Upper Bound 2007 Depth (%TW) (for CM)	Projected 2010 Depth (%TW) (for OA)
SG	Row	Col	AVB No.	2003	2007	2003	2007		
B	26	61	AV3	0.00	-0.02	13	11	28	39
B	32	26	AV3	-	0.00	-	10	27	38
B	34	58	AV2	0.00	0.00	22	22	39	50
B	34	58	AV3	0.00	0.00	17	17	34	45
B	34	58	AV4	0.00	-	10	-	-	-
B	35	17	AV2	-0.03	0.07	12	10	27	38
B	35	17	AV3	0.00	0.05	17	20	37	48
B	35	18	AV2	-0.05	-	13	-	-	-
B	38	21	AV1	0.27	0.27	13	13	30	41
B	38	21	AV2	0.24	-	12	-	-	-
B	38	22	AV2	0.19	-	10	-	-	-
B	38	22	AV3	-	-0.12	-	9	26	37
B	39	25	AV3	0.00	-	10	-	-	-
B	40	25	AV2	0.00	0.00	19	21	38	49
B	41	27	AV2	0.00	0.00	12	11	28	39
B	41	27	AV3	0	0	13	8	25	36
B	42	29	AV2	0	0	16	15	32	43
B	42	30	AV4	-0.22	-0.1	12	10	27	38

ETSS- examination technique specification sheets
CM- condition monitoring
OA- operational assessment

Notes

- SG-B Number of Tubes With AVB Indications Reported in 2007: 10
- SG-B Number of New Indications Not Present Previously Based on Historical Lookups: 0
- SG-B Average Wear Rate Prior to This Outage (%TW/Cycle): 1.66 (41 points)
- SG-B Average Wear Rate Including This Outage (%TW/Cycle): 1.41 (54 points)
- 95/50 Wear Rate Based on Unit 1 Current & Historical Data: 5.77 %TW/Cycle
- Total Random Sizing Uncertainty at 95/50: 13.7 %TW
- Upper Bound 2007 Depth: [0.97] x [Field Call] + [3.49] + [13.7]
- Fall 2010 Projected Depth: [Upper Bound 2007 Depth] + (5.77 %TW/Cycle) x 2 Cycles]

Table 4 – Summary of Non-AVB Wear Volumetric Degradation Identified

SG	Row	Col	Location	Axial Length (in)	Circ. Length (in)	ETSS 21998.1 Max Depth (%TW)	ETSS 27901.1 Max Depth (%TW)	Comments	Present Previously	Foreign Object Remaining?	In-Situ Tested?	Plugged?
B	1	7	TSH+0.22"	0.90	0.34	26	na	Visually observed mechanical damage. Mechanical damage also visible at same location on the cold side but too shallow to detect with +Point. May have been caused by a previous SG maintenance activity.	Not visible in 1998 RPC probe data or 2003 bobbin data.	No	No	No
B	40	50	TSH+0.32"	0.30	0.45	30	36	Damage is attributed to historical foreign object wear. No object was found immediately adjacent to these tubes during this inspection. Other objects were observed and removed from the general vicinity of these tubes.	Yes, RPC 1998, no change. Not visible in bobbin data	No	No	No
B	40	51	TSH+0.35"	0.35	0.42	29	36		Yes, RPC 1998, no change. Not visible in bobbin data	No	No	No
B	41	51	TSH+0.19"	0.35	0.34	26	28		Not visible in 1998 or 2003 bobbin probe data. (No RPC)	No	No	No

TSH- top of tube sheet

Table 5 - Steam Generator Tube Plugged During EOC21

AREVA

Surry Unit 1 - EOC21/REOC16 - S/G 1B
PLUG LIST (Rev. 0)

S/G	Row	Col	Hot Leg	Cold Leg	Reason for Tube Repair	Tube Qty.	Stab	Rev.
SURRY1B	11	88	ROLLED	ROLLED	PVN @ 2C+42.64	1	NO	0
					Totals:	1	0	

Notes (Rev. 0):

1. All tubes shall be plugged using a .875 Threaded Roll Plug Assembly. LDPE Finger - part number 1222366-004.
2. The tubes on the above list have been reviewed for skip rolls, over expansions, dents, bulges and additional indications. No such anomalies or indication that would prohibit installation of the plugs were detected.
3. The indications in the tubes on the above list have been screened against the in situ screening criteria.
4. The indications identified on this list as requiring plugging are consistent with those specified in the Analysis Guidelines and include: AVB Wear >= 30%, OBS, MAI, MCI, MVI, PVN, SAI, SCI, (SVI and VOL >= 40% or with PLP).
5. All planned eddy current examinations for these tubes have been successfully completed and confirmed by Data Management Personnel.

Approvals:

11-3-07
Kent Colgan, AREVA NP Integrity Engineering

for: Viki Armentrout, Fleet SG Program Owner, Dominion

11/3/07
Carlton Wirt, AREVA NP Data Management

Todd Mayer, Surry SG Program Owner, Dominion

for: Mike Story, AREVA NP Lead Analyst

11/3/2007 8:24 PM

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Table 6- Plugging Attributes

SURRY POWER STATION UNIT #1
PLUGGING ATTRIBUTES

DATE	Preservice			Mar-83			Nov-84			Jun-86			Apr-88			Oct-90			Mar-92			Feb-94			Oct-95		
EFPY	0			1.3			2.3			3.4			4.7			6			7.1			8.7			10.1		
S/G	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
AVB																			1				4				1
Freespan																			1								
Tube Pulls												1						2									
Foreign Object																											
Pitting																											
Anomalies																											
Other	1	1					3	1			2	1															
Sub-Total	1	1	0	0	0	0	3	1	0	0	2	2	0	0	0	0	0	2	2	0	0	0	4	0	0	0	1
TOTAL	2			0			4			4			0			2			2			4			1		

DATE	Mar-97			Oct-98			Apr-00			Oct-01			Apr-03			Nov-04			Apr-06			Oct-07			Total per S/G		
EFPY	11.4			12.7			14.1			15.5			16.8			18.2			19.5								
S/G	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C	A	B	C
AVB	1								8	2											1				4	4	10
Freespan																									1	0	0
Tube Pulls																									0	0	3
Foreign Object					3														6		2				6	3	2
Pitting																									0	0	0
Anomalies																									0	0	0
Other	4				3					3				7	4				7				1		18	15	5
Sub-Total	5	0	0	0	6	0	0	0	8	5	0	0	0	7	4	0	0	0	13	0	3	0	1	0	29	22	20
TOTAL	5			6			8			5			11			0			16			1			71		

Total tubes plugged by category
18 AVB 1 Freespan 3 Tube Pulls 11 Foreign Objects 0 Pitting 0 Anomalies 38 Other

EFPY- effective full power years

Table 7 – Tube Plugging Summary

	Tubes Installed	Tubes Plugged To-Date
SG "A"	3,342	29 (0.9%)
SG "B"	3,342	22 (0.7%)
SG "C"	3,342	20 (0.6%)
Total	10,026	71 (0.7%)