VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

November 6, 2015

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 SPRING 2015 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 Spring 2015 refueling outage.

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

Very truly yours,

N. L. Lane
Site Vice President
Surry Power Station

Attachment: Surry Unit 1 Steam Generator Tube Inspection Report for the Spring 2015 Refueling Outage

Commitments made in this letter: None

A001
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ATTACHMENT

SURRY UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT
FOR THE SPRING 2015 REFUELING OUTAGE

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)

SURRY UNIT 1
STEAM GENERATOR TUBE INSPECTION REPORT
FOR THE SPRING 2015 REFUELING OUTAGE

The following satisfies the Surry Power Station Technical Specification (TS) reporting requirement section 6.6.A.3. During the Surry Unit 1 Spring 2015 refueling outage (RFO), steam generator (SG) inspections in accordance with TS 6.4.Q were completed for SG A and SG C.

This was the second inspection in the 4th inspection period which has duration of 72 effective full power months (EFPM).

Surry Unit 1 exceeded 200°F on May, 24 2015; therefore, this report is required to be submitted by November 20, 2015. The Surry Unit 1 SGs were replaced during Refueling Outage 5 (1981) and have accrued approximately 27.8 effective full power years (EFPY) of operation as of April 2015. Programmatically, the first sequential period begins after the first inservice inspection, thus the current SGs have accrued 317.7 EFPM.

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 included at the end of the 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,

A summary of the tube examinations performed during the outage is provided in Table 1.

The primary side inspection activities included an as-found and as-left video/visual examination of both channel heads in SG A and SG C, specifically including:

- All plugs; there was no evidence of plug leakage.
- The divider plate weld region; no indications of degradation.
- The bottom of the bowl per NSAL-12-1 and NRC IN 2013-20 with the bowl dry.

No abnormal or degraded conditions were identified.

Table 1 - Primary Side Examination Scope

Scope Description	Extent	SG A Exams Completed	SG C Exams Completed
Bobbin Coil Exams			
Full Length	TEC TEH	2838	2844
H/L Straight (Row 1-2)	07H TEH	182	185
H/L Candycane (Row 3-5)	07C TEH	277	277
C/L Straight (Row 1-5)	07C TEC	459	458
C/L Candycane (Row 3)	07H TEC	0	4
Restricted Tubes	Various	2	2
Array Exams			
H/L TSH Array (Baffle Plate)	BPH TEH	2463	2469
H/L TSH Array (Non-Baffle Plate)	01H TEH	835	837
C/L TSC Array (Baffle Plate)	BPC TEC	2463	2469
C/L TSC Array (Non-Baffle Plate)	01C TEC	835	837
Low Row U-bend MRPC Exams			
U-bend +Point (Row 1-2)	07C 07H	181	183
MRPC Special Interest			
U-bend Historical Spec Int	Various	2	2
H/L Historical Spec Int	Various	222	205
C/L Historical Spec Int	Various	6	5
U-bend 1R26 Spec Int	Various	15	1
H/L 1R26 Spec Int	Various	16	39
C/L 1R26 Spec Int	Various	47	24
Mag Bias Spec Int	Various	3	8
1R26 PLP Bounding	02H 02H	0	8

Note: The H/L and C/L Array Exams were analyzed down to the H-star dimension.

The following secondary side SG activities were performed during the Spring 2015 RFO:

SGs A, B, and C:

- Upper bundle flush, sludge lancing, and post-lancing visual examination of the top-of-tubesheet annulus and no-tube lane to identify and remove any retrievable foreign objects (FOSAR).
- Visual examination of historical foreign object-related locations identified in the Degradation Assessment.
- Visual investigation of any accessible locations having eddy current signals potentially related to foreign objects.

No degradation or adverse conditions were noted.

SG A:

- Visual examination of accessible steam drum components and structures (including the feedring exterior), the upper tube bundle, and 7^{th} TSP via probe drops through the primary moisture separators. No degradation or adverse conditions were noted during this inspection.

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 steam generator tube bundle. AVB wear, foreign object wear, tube support plate wear, one legacy pit indication, and one legacy sludge lance wear flaw were detected. No SCC was detected.

c. Nondestructive examination techniques utilized for each degradation mechanism,

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

Table 2 – Inspection Method for Applicable Degradation Modes

Classification	Degradation Mechanism	Location	Probe Type
Existing	Tube Wear	Anti-vibration Bars	Bobbin – Detection Bobbin and +PointTM – Sizing
Existing	Tube Wear	Tube Support Plate	Bobbin – Detection Bobbin and +PointTM – Sizing
Existing	Tube Wear (foreign objects)	Freespan, TTS, FDB, TSPs	Bobbin and Array – Detection +PointTM - Sizing
Existing	ODSCC	Hot Leg Top-of-tubesheet Sludge Pile Area	Bobbin and Array – Detection +PointTM - Sizing
Existing	PWSCC	At the Tube Ends TE + 4 Inches	Inspection not required per PARC
Existing	PWSCC	Hot Leg Top-of-tubesheet	Array – Detection and Sizing
Existing	OD Pitting	Top-of-tubesheet	Bobbin – Detection +PointTM - Sizing
Potential	Tube Wear	Flow Distribution Baffle	Bobbin – Detection Bobbin and +PointTM – Sizing
Potential	ODSCC	Freespan and Tube Supports	Array – Detection +PointTM – Sizing
Potential	PWSCC	Hot Leg within Tubesheet Anomaly Locations	Array – Detection +PointTM – Sizing

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

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

Table 3 – AVB Indications

SG	Row	Col	AVB No.	Depth (%TW) (ETSS 96041.1)	
				2012	2015
SGA	9	54	AV1	11	13
SGA	12	45	AV2	11	14
SGA	12	45	AV4	-	13
SGA	12	47	AV4	13	15
SGA	30	57	AV2	15	14
SGA	30	57	AV3	-	13
SGA	32	14	AV4	-	10
SGA	32	48	AV3	14	15
SGA	32	65	AV2	11	12
SGA	32	66	AV2	11	15
SGA	32	69	AV2	22	23
SGA	32	69	AV3	15	17
SGA	32	69	AV4	19	19
SGA	33	16	AV2	12	12
SGA	33	63	AV3	20	26
SGA	33	63	AV4	15	22
SGA	33	66	AV1	12	15
SGA	33	66	AV2	15	15
SGA	34	59	AV2	11	17
SGA	35	17	AV2	10	11
SGA	35	78	AV2	14	15
SGA	36	47	AV1	11	13
SGA	36	75	AV2	15	15
SGA	36	76	AV2	10	10
SGA	37	75	AV2	11	12
SGA	38	62	AV4	10	10
SGA	39	42	AV1	12	20
SGA	39	71	AV4	10	11
SGA	39	72	AV4	15	14
SGA	40	42	AV1	14	21
SGA	40	69	AV4	13	11

Table 3 – AVB Indications (continued)

SGA	45	40	AV4	-	14
SGA	46	43	AV1	12	11
SGA	46	43	AV2	-	10
SGA	46	44	AV1	13	14
SGA	46	44	AV4	-	12
SGA	46	45	AV1	15	12
SGA	46	45	AV4	10	9
SGC	22	7	AV3	-	10
SGC	24	33	AV2	10	8
SGC	27	10	AV3	12	11
SGC	33	16	AV2	11	10
SGC	35	17	AV1	25	24
SGC	35	17	AV4	11	10
SGC	35	46	AV2	12	10
SGC	35	46	AV3	15	10
SGC	35	77	AV3	-	13
SGC	37	24	AV2	-	11
SGC	38	67	AV3	24	23
SGC	39	23	AV1	18	18
SGC	39	23	AV2	20	20
SGC	39	23	AV3	26	27
SGC	39	69	AV3	15	15
SGC	40	66	AV2	-	11
SGC	42	31	AV1	23	20
SGC	42	31	AV2	23	20
SGC	42	31	AV3	19	17
SGC	42	31	AV4	15	11
SGC	44	47	AV3	10	7
SGC	44	59	AV2	-	10
SGC	45	38	AV3	10	8
SGC	45	40	AV4	12	11
SGC	45	58	AV1	-	11
SGC	45	58	AV4	10	11

- Not reported during the 2012 outage.

Table 4 - 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 and Stabilized
SGA	1	86	TSC +16.01"	21998.1	31%TW	0.77	0.43	2015	Yes (2001). No change.	Lancing Equipment Damage	N/A	No	No
SGA	2	57	06C -0.34"	96910.1	16%TW	0.24	0.38	2006	Yes. No change since initially reported.	TSP Wear	N/A	No	No
SGA	3	66	05C -0.69"	27901.1	28%TW	0.19	0.32	2009	Yes. No change since initially reported.	Foreign Object	No	No	No
SGA	6	88	TSH +0.35":	27901.1	26%TW	0.18	0.42	2006	Yes. No change since initially reported.	Foreign Object	No	No	No
SGA	8	38	TSH +0.41"	21998.1	16%TW	0.19	0.38	2001	Yes. No change since initially reported.	Legacy Pitting	No	No	No
SGA	34	67	TSH +0.05"	27901.1	25%TW	0.29	0.37	2006	Yes. No change since initially reported.	Foreign Object	No	No	No
SGA	38	30	TSC +1.96"	27901.1	20%TW	0.24	0.37	2006	Yes. No change since initially reported.	Foreign Object	No	No	No
SGC	3	52	TSC +0.37"	27901.1	33%TW	0.27	0.37	2015	Not detectable with bobbin. No previous +Point™.	Foreign Object	No	No	No
SGC	4	68	06C -0.28"	96910.1	9%TW	0.34	0.38	2015	Yes (2006). Some change since 2006.	TSP Wear	N/A	No	No
SGC	27	82	BPH +0.67"	27901.1	28%TW	0.23	0.49	2010	Yes (2000). No change since 2000.	Foreign Object	No	No	No
SGC	29	77	02H -0.32"	27901.1	33%TW	0.23	0.43	2015	No.	Foreign Object	Yes	No	Yes
SGC	36	24	BPH -0.17"	96910.1	5%TW	0.23	0.38	2012	Yes (2006). Not present in 2000.	TSP Wear	N/A	No	No
SGC	36	64	TSC -0.02"	27901.1	32%TW	0.27	0.48	2012	Yes. No change since initially reported.	Foreign Object	No	No	No
SGC	36	66	TSC +0.03"	27901.1	26%TW	0.28	0.43	2015	Not detectable with bobbin. No previous +Point™.	Foreign Object	No	No	No
SGC	38	66	TSC -0.53"	27901.1	28%TW	0.33	0.53	2009	Yes. No change since initially reported.	Foreign Object	No	No	No
SGC	44	50	BPH -0.26"	96910.1	4%TW	0.24	0.32	2015	Not detectable with bobbin. No previous +Point™.	TSP Wear	N/A	No	No
SGC	45	52	BPH -0.31"	96910.1	4%TW	0.24	0.38	2015	Not detectable with bobbin. No previous +Point™.	TSP Wear	N/A	No	No

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

A total of five tubes in SG C were plugged during the Spring 2015 RFO. One tube required plugging as a result of SG inspections performed during the outage. This tube was plugged due to a foreign object wear indication with the foreign object still present and was stabilized on the hot leg. Four additional tubes were preventatively plugged due to permeability signals. These tubes were tested with a magnetically biased probe. It was determined that they had no degradation and, therefore, met condition monitoring.

No tube plugging was required or performed in SG A.

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

Table 5 provides the plugging totals and percentages to date.

Table 5 – 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,

Based on results of the primary and secondary side inspections performed during this outage, the condition monitoring assessment for the Spring 2015 RFO concluded that the Surry Unit 1 SGs satisfy required structural and leakage integrity criteria. Therefore, pull tubes and in-situ 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 the Spring 2015 RFO, no measurable primary-to-secondary leakage (i.e., >1 GPD) was observed.

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) require 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 A or SG C.

No bobbin probe examinations were performed in SG B during the Spring 2015 RFO. All tubes in SG B were screened for slippage during the Fall 2013 RFO with no indications identified. The SG B tubes will again be screened during the Fall 2016 RFO.

Acronyms

AILPC	Accident Induced Leakage Performance Criteria
ARC	Alternate Repair Criteria
AVB	Anti-Vibration Bar
BET	Bottom of Expansion Transition
BOC	Beginning of Cycle
BPC	Baffle Plate Cold
BPH	Baffle Plate Hot
CDS	Computer Data Screening
C/L	Cold Leg
CM	Condition Monitoring Assessment
DA	Degradation Assessment
DMT	Deposit Minimization Treatment
ECT	Eddy Current Test
EFPM	Effective Full Power Months
EFPY	Effective Full Power Years
EOC	End of Cycle
ETSS	Examination Technique Specification Sheet
FK	Foreign Object Identifier
FAC	Flow Assisted Corrosion
FDB	Flow Distribution Baffle
FOSAR	Foreign Object Search and Retrieval
GPD	Gallons per Day
H/L	Hot Leg
MRPC	Motorized Rotating Pancake Coil
NTE	No Tube Expansion
OA	Operational Assessment
OD	Outer Diameter
ODSCC	Outer Diameter Stress Corrosion Cracking
PARC	Permanent Alternate Repair Criteria
PDA	Percent Degraded Area
PLP	Possible Loose Part
POD	Probability of Detection
PWSCC	Primary Water Stress Corrosion Cracking
PTE	Partial Tube Expansion
QDA	Qualified Data Analyst
REOC	Replacement End of Cycle
RPC	Rotating Pancake Coil (also a generic term for rotating probes of any kind)
SCC	Stress Corrosion Cracking
SG	Steam Generator
SIPC	Structural Integrity Performance Criteria
SSI	Secondary Side Inspection
TE	Tube End
TEC	Tube End Cold
TEH	Tube End Hot
TSC	Tube Sheet Cold
TSH	Tube Sheet Hot
TSP	Tube Support Plate
TTS	Top of Tubesheet