VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

November 4, 2009

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

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 1
STEAM GENERATOR TUBE INSERVICE INSPECTION REPORT FOR THE 2009 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 2009 refueling outage.

If you have any questions or require additional information, please contact Mr. Trace J. Niemi at 757-365-2848.

Sincerely,

B. L. Stanley
Director Safety and Licensing
Surry Power Station

Attachment

Commitments made in this letter: None

A047
NRR

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ATTACHMENT

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

Surry Power Station
Virginia Electric and Power Company

180-DAY NRC REPORT REGARDING STEAM GENERATOR TUBE INSPECTION SURRY UNIT 1 - SPRING 2009 END-OF-CYCLE 22 (EOC22) / REPLACEMENT-END-OF-CYCLE 17 (REOC17)

The following information satisfies the Surry Power Station Technical Specification (TS) reporting requirement section 6.6.A.3. During the Surry spring 2009 refueling outage, steam generator (SG) inspections were completed for all three SGs in accordance with TS 6.4.Q.

The Unit 1 SGs are now in the 3rd inspection period which has a duration of 60 Effective Full Power Months (EFPM). The spring 2009 outage was the first outage of two in the second half of the 3rd period.

TS 6.6.A.3 requires a SG Tube Inspection Report to be submitted to the NRC within 180 days following the unit exceeding 200°F. Unit 1 exceeded 200°F on May 9, 2009, therefore this report is required to be submitted by November 5, 2009. At the time of this inspection, the current SGs had operated for 251.0 EFPM since the first inservice inspection.

For EOC22, an Interim Alternate Repair Criterion (IARC) to address primary water stress corrosion indications was submitted for the bottom 4 inches of the tubesheet expansion zone (Surry Unit 1 Tech Spec Amendment 263). The IARC requires inspection of the tubesheet region, and plugging of any tubes which exhibit circumferentially oriented cracks greater than 94° in the 1 inch span above the tube-end, and greater than 203° in the 3 inches above the 1 inch zone. Circumferentially oriented cracks of less than these magnitudes and all axial cracks are acceptable for continued operation in these regions. Leakage observed from the tubesheet expansion zone must be multiplied by a factor of 2.5 to determine accident induced leakage from the tubesheet region.

The report information is provided under each ***bold italicized*** TS 6.6.A.3 item shown below.

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

The following Tables 1 through 3 primary side inspections were performed in the Unit 1 SGs during this refueling outage.

Table 1 Initial Examination Scope

Scope	SG "A"	SG "B"	SG "C"
Bobbin probe: 100% Full Length (except for Row 1 and 2 U-bends)	X		X
Rotating Probe: 58% H/L Expansion Transition (TSH +/- 3")	X		X
Rotating Probe: Tier 1 High Stress Tubes (TEH to TSH+3")	X		X
Rotating Probe: 100% Row 1 and 2 U-bends (07C to 07H)	X		X
Rotating Probe: 50% H/L Tube End Sample (TEH to TEH+4")	X		X
Rotating Probe: 50% H/L OXP Sample (TEH to TSH+3") (include 5 largest voltage)	X		X
Rotating Probe: 20 Largest Voltage C/L OXPs (TEC to TSC+3")	X		X

Table 2 Tube End Scope Expansion Sequence

SG	Initial Sample	Expansion 1	Expansion 2	Final Sample
A	50% H/L	100% H/L 20% C/L		100% H/L 20% C/L
B		20% H/L	100% H/L 100% C/L	100% H/L 100% C/L
C	50% H/L	100% H/L 20% C/L		100% H/L 20% C/L

Table 3 High Stress Tube Examination Scope Expansion

		SG "A"	SG "B"	SG "C"
Rotating Probe	**Tier 1 High Stress Tubes** Sample: 100% Extent: TEH to TSH+3" Extent: TEC to TSC+3"	(Note 1) 19	22 22	(Note 1) 3
Rotating Probe	**Tier 1 High Stress Tubes** Sample (regardless of location): All current and previous H-Codes and S-Codes All previous A-Codes All current DNT, BLG, OVR, LGV, MBM	(Note 2)	7	(Note 2)
Rotating Probe	**Tier 1 High Stress Tubes** Sample: All current AVB wear indications	0	0	0
Rotating Probe	**Tier 1 High Stress Tubes** *Sample: As originally scheduled at all hot supports* Extent: Change originally scheduled 07H extent from 07H±2" to 07H-2"/+8"	10	0	3
Rotating Probe	**Tier 2 High Stress Tubes** Sample: 20% chosen from the top of the list (ie. lowest "Rank" which means highest susceptibility) Extent: TEH to TSH+3" Extent: TEC to TEC+3"	33 33	23 23	24 24
Rotating Probe	**Tier 2 High Stress Tubes** Sample: Remaining 80% Extent: TSH±3"	n/a	87	n/a
Bobbin Probe (Note 4)	**Tier 1 High Stress Tubes** Sample: 100% Extent: Full length	(Note 3)	22	(Note 3)
Bobbin Probe (Note 4)	**Tier 2 High Stress Tubes** Sample: 100% Extent: Full length	(Note 3)	110	(Note 3)

Note 1: 100% of hot leg already included in original scope
Note 2: Already included in original special interest criteria
Note 3: 100% already included in original scope
Note 4: All bobbin results are subject to the same special interest criteria identified in the degradation assessment

The following special interest rotating +Point™ probe inspection criteria was also applied during the EOC22 outage:

- All bobbin "I-codes"
- All PLP, PVN, OVR, BLG, and LGV
- All DNT with "NEW" in Util1 field of eddy current program
- Previous foreign-object related locations
- Bound (1 tube deep) all RPC-confirmed PLPs
- Bound (1 tube deep) all newly reported non-AVB VOL, non-AVB WAR, and non-AVB SVI that could have been caused by a foreign object
- All previously reported PITs, "A-Codes", LPS, LPM, and RPC-confirmed PLPs
- All indications of tube wall loss previously reported and sized with an RPC probe (excluding AVB wear)
- All tube regions which cannot be examined effectively with the bobbin probe due to data quality concerns
- All NTE/PTE from the top-of-tubesheet down to and including the location of the expansion transition
- 50% of DNTs located in hot leg straight sections (TEH to 07H+1 inch), plus any additional required to ensure that the five largest voltage DNT in hot leg straight sections are included in the sample (any DNTs tested with RPC under other scopes count towards the 50% sample)
- All hot leg manufacturing anomalies
- The five largest voltage DNTs located between TEC and 07H+1.0 inch
- A sample of hot leg MBM/MBH (20% or 20 tests whichever is less)
- Positive identification (PID) retests to include:
  - Bobbin indications: OBSs and degradation sized greater than 40%TW
  - RPC indications: MAI, MCI, MMI, MVI, OBS, PIT, PVN, SAI, SCI, SVI, VOL, WAR
  - Any location with an eddy current indication which has caused the tube to be placed on the plugging list

A summary of the secondary side work performed in the Surry Unit 1 SGs during the EOC22 outage is provided below. It should be noted that the original inspection plan called for the steam drum, J-nozzle, and top of bundle inspections in SG "C"; however due to outage schedule and work flow changes, these inspections were instead performed in SG "A".

SG "A":

- Steam drum visual inspection and video documentation
- Internal feed-ring visual inspection of all J-nozzle interfaces
- Visual top of tube bundle inspection via the primary moisture separator risers
- Post Deposit Minimization Treatment (DMT) and pre-water lancing inspection of the flow distribution baffle
- Investigation of 4 eddy current PLP calls
- Retrieval of two loose parts (small pieces of wire)
- Attempted retrieval of an approximately 1/8 inch diameter x 7 inches long wire. This wire could not be removed due to its shape and the limiting distance between the tubes.
- Attempted retrieval of a small disc shaped object wedged between tubes. This object could not be removed.

SGs A, B, C:

- Baffle plate and top of tubesheet water lancing and sludge sample retrieval for chemical analysis
- Post sludge lancing top of tubesheet foreign object search and retrieval (FOSAR)
- Post sludge lancing quick look on top of tubesheet and baffle plates to determine lancing effectiveness
- In bundle inspection passes to evaluate the effect of DMT and 3000 psi water lancing on legacy hard deposits
- Visual investigation of historical foreign objects
- Application of the DMT cleaning process

b. Active degradation mechanisms found

Degradation mechanisms targeted by the inspection plan included anti-vibration bar (AVB) wear, pitting, foreign object wear, tube support wear as well as stress corrosion cracking (SCC) at various locations within the SG tube bundle. AVB wear, foreign object wear, tube support plate wear, legacy maintenance-related wear, and legacy pitting flaws were detected. In addition, SCC was detected at the hot leg top of tubesheet in SG "A," and at the hot leg tube ends in all three SGs. Lists of service induced indications are located in Section "d".

c. Nondestructive examination techniques utilized for each degradation mechanism

Inspections focused on the degradation mechanisms listed in Table 4 utilizing the referenced eddy current techniques.

Table 4 – Inspection Method for Applicable Degradation Modes

Classification	Degradation Mechanism	Location	Probe Type
Existing	Tube Wear	Anti-Vibration Bars	Bobbin – Detection Bobbin – Sizing
Potential	Tube Wear	Flow Distribution Baffle	Bobbin – Detection +Point™ – Sizing
Potential	Tube Wear	Tube Support Plate	Bobbin – Detection +Point™ – Sizing
Existing	Tube Wear (foreign objects)	Freespan and TTS	Bobbin – Detection +Point™ - Sizing
Potential	ODSCC	Hot Leg Top-of-Tubesheet Sludge Pile Area and Crevice in Tubes w/o Expansion	Bobbin and +Point™ – Detection +Point™ - Sizing
Potential	PWSCC	Hot Leg Top-of-Tubesheet and Within Tubesheet at Overexpansions and Manufacturing Anomalies	+Point™ – Detection and Sizing
Potential	PWSCC	At the Tube ends	+Point™ – Detection and Sizing
Potential	ODSCC PWSCC	Row 1 U-bends and Hot Leg OVR, BLG and Dent Locations	+Point™ – Detection and Sizing
Potential	ODSCC	Freespan and Tube Supports	+Point™ – Detection and Sizing
Existing	OD Pitting	Top-of-Tubesheet	Bobbin and +Point™ – Detection +Point™ - Sizing

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

As discussed in Section "b", AVB wear and other miscellaneous types of volumetric degradation were detected during this examination. Tables 5 and 6 provide the required information for these indications.

Table 5 – AVB Wear Indications

SG	Row	Col	AVB No.	Location (inch)	Depth (%TW) (EPRI ETSS 96004.1)
A	9	54	AV1	0.25	11
A	12	45	AV2	0.13	11
A	12	47	AV4	-0.4	14
A	30	57	AV2	-0.22	16
A	32	48	AV3	0.46	15
A	32	65	AV2	0	14
A	32	69	AV2	0	22
A	32	69	AV3	0	17
A	32	69	AV4	-0.1	19
A	33	16	AV2	0	11
A	33	63	AV3	-0.12	20
A	33	63	AV4	0.05	14
A	33	66	AV1	-0.02	10
A	33	66	AV2	0.19	12
A	34	59	AV2	0.05	14
A	35	78	AV2	0	12
A	36	75	AV2	-0.02	14
A	36	76	AV2	0	12
A	37	75	AV2	0.02	12
A	38	62	AV4	0.14	10
A	39	42	AV1	0.05	11
A	39	71	AV4	0.07	11
A	39	72	AV2	0.1	10
A	39	72	AV4	0.02	14
A	40	42	AV1	0.05	13
A	40	69	AV4	-0.12	11
A	46	43	AV1	0.14	11
A	46	44	AV1	-0.25	13
A	46	45	AV1	0.05	14
A	46	45	AV4	-0.07	10
C	27	10	AV3	-0.05	11
C	35	17	AV1	-0.04	20
C	35	17	AV4	-0.02	10
C	35	46	AV3	0.27	13
C	38	67	AV3	-0.02	16
C	39	23	AV1	0	16
C	39	23	AV2	0.05	18
C	39	23	AV3	-0.02	22
C	39	69	AV3	0.07	15
C	42	31	AV1	-0.02	19
C	42	31	AV2	0.02	19
C	42	31	AV3	0.1	16
C	42	31	AV4	-0.05	13
C	44	47	AV3	-0.02	11
C	44	55	AV3	0	12
C	45	38	AV3	-0.02	10
C	45	40	AV4	0	13
C	45	57	AV1	-0.05	14
C	45	58	AV4	-0.12	11

Table 6 – Summary of Non-AVB Wear Volumetric Degradation Identified

SG	Row	Col	Location	Max Depth (%TW)	Axial Length (in)	Circ. Length (in)	Comments	Present Previously	Cause	Foreign Object Remaining?
A	2	57	06C-0.42"	14%TW ETSS 96910.1	0.29	0.34	Initially reported and sized in 2006.	Yes. No signal change.	TSP Wear	n/a
A	3	66	05C-0.78"	26%TW ETSS 27901.1	0.32	0.32	Initially reported in 2009. Initially detected with bobbin	Bobbin signal present in 1997, 2001, 2006, & 2009 - No change	Foreign Object	No
A	6	88	TSH+0.35"	27%TW ETSS 27901.1	0.3	0.4	Initially reported and sized in 2006 (2009 sizing technique is more conservative than that used in 2006)	Yes. No signal change.	Foreign Object	No
A	8	38	TSH+0.42"	25%TW ETSS 21998.1	0.34	0.37	Historical PIT	Yes. No signal change.	Legacy Pitting	No
A	27	84	BPH+0.51"	40%TW ETSS 27901.1	0.40	0.45	Initially reported and sized in 2006 (2009 sizing technique is more conservative than that used in 2006)	Yes. No signal change.	Foreign Object	No
			BPH+0.71"	24%TW ETSS 27901.1	0.37	0.42	Initially reported and sized in 2009	Yes. No signal change.	Foreign Object	No
A	34	67	TSH+0.09"	27%TW ETSS 27901.1	0.27	0.42	Initially reported and sized in 2006. (2009 sizing technique is more conservative than that used in 2006)	Yes. No signal change.	Foreign Object	No

Table 6 – Summary of Non-AVB Wear Volumetric Degradation Identified (continued)

SG	Row	Col	Location	Max Depth (%TW)	Axial Length (in)	Circ. Length (in)	Comments	Present Previously	Cause	Foreign Object Remaining?
A	38	30	TSC+1.87"	23%TW ETSS 21998.1	0.32	0.42	Historical PIT	Yes. No signal change.	Legacy Pitting	No
B	1	7	TSH+0.30"	23%TW ETSS 21998.1 16%TW ETSS 27902.1	0.92	0.40	Initially *reported and* sized in 2007	Yes. *No signal* change.	Historical SG Maint-enance	No
B	40	50	TSH+0.29"	33%TW ETSS 27901.1	0.38	0.47	Initially reported and sized in 2007	Yes. No signal change.	Foreign Object	No
B	40	51	TSH+0.31"	36%TW ETSS 27901.1	0.35	0.45	Initially reported and sized in 2007	Yes. No signal change.	Foreign Object	No
B	41	51	TSH+0.17"	27%TW ETSS 27901.1	0.25	0.34	Initially reported and sized in 2007	Yes. No signal change.	Foreign Object	No
C	10	26	1H-0.69"	59%TW ETSS 27901.1 (SD=52.3%TW)	0.33 (SL=0.22")	0.37	Initially reported in 2009; Initially detected with bobbin. Flaw is located at the lower edge of a TSP land	No (2006)	Foreign Object	No
C	38	66	TSC+0.10"	30%TW ETSS 27901.1	0.38	0.52	Initially reported in 2009. Initially detected with bobbin	No (2006)	Foreign Object	No

SD=structurally significant depth. SL=structurally significant length

Stress Corrosion Cracking (SCC) was detected at the hot leg tube ends in all three SGs and at the hot leg top-of-tubesheet in SG "A". The required information for these indications is provided in Tables 7 and 8, respectively.

Table 7 – Hot Leg Tube End SCC Listing

SG ID	ROW	COL	IND	VOLTS	LOC	Extent
1A	1	5	SAS	2.12	TEH + 0.1	0.22
1A	1	34	SAS	2.93	TEH + 0.13	0.19
1A	1	38	SAS	4.82	TEH + 0.11	0.36
1A	1	49	SCI	1.67	TEH + 0.02	174
			SCI	2.62	TEH + 0.03	
1A	1	55	SAS	6.79	TEH + 0.11	0.25
1A	1	57	SAS	2.24	TEH + 0.1	0.28
1A	1	63	SAS	0.96	TEH + 0.08	0.17
1A	1	64	SAS	3.66	TEH + 0.06	0.25
1A	2	31	SCS	0.95	TEH + 0.02	38
1A	2	34	SAS	2.67	TEH + 0.08	0.25
1A	2	62	SAS	2.31	TEH + 0.08	0.24
1A	2	63	SAS	3.41	TEH + 0.08	0.36
1A	3	52	SAS	1.58	TEH + 0.11	0.3
1A	6	61	SCI	1.34	TEH + 0.05	118
1A			SCI	1.21	TEH + 0.04	
1A	7	59	SCS	0.73	TEH + 0.06	31
1A	8	56	SCS	1.67	TEH + 0.05	31
1A	8	58	SCS	1.15	TEH + 0.04	45
1A	9	33	MAS	3.13	TEH + 0.11	0.18
1A	9	59	SCS	4.04	TEH + 0.02	80
			SCS	0.75	TEH + 0.05	
1A	9	69	MAS	2.57	TEH + 0.12	0.15
1A	10	51	SCS	1.48	TEH + 0	91
1A	11	44	SCS	1.11	TEH + 0.06	28
1A	11	51	SCS	1.03	TEH + 0.01	35
1A	11	54	SCS	2.63	TEH + 0.05	38
1A	12	53	SCS	1.32	TEH + 0.04	49
1A	12	55	SCI	2.33	TEH + 0.02	178
1A	13	49	SCS	0.99	TEH + 0.02	38
1A	13	51	SCS	3.78	TEH + 0.02	42
1A	13	52	SCS	1.47	TEH + 0.05	28
1A	13	55	SCI	6.59	TEH + 0.01	171
			SCI	2.82	TEH + 0.01	
1A	13	57	SCS	3.96	TEH + 0.04	35
1A	14	33	SCS	0.86	TEH + 0	31
1A	14	55	SCI	1.91	TEH + 0.07	114
			SCI	1.23	TEH + 0.08	
			SCI	0.85	TEH + 0.06	
1A	14	58	SCS	4.51	TEH + 0.05	76
1A	15	51	SCS	0.73	TEH + 0.01	77
			SCS	0.47	TEH + 0.02	
1A	16	35	SCS	1.83	TEH + 0.01	45
1A	18	55	SCS	0.98	TEH + 0.05	84
1A	18	58	SCS	2.09	TEH + 0.04	45
1A	19	57	SCS	1.4	TEH + 0.05	59
1A	19	62	SCI	0.8	TEH + 0.34	164
1A	23	49	SCI	3.56	TEH + 0.02	118
			SCI	0.51	TEH + 0.03	
1A	24	51	SCS	1.23	TEH + 0.05	59

Table 7 – Hot Leg Tube End SCC Listing (continued)

SG ID	ROW	COL	IND	VOLTS	LOC	Extent
1A	25	48	SCS	1.19	TEH + 0.05	70
1A	26	57	SCS	0.98	TEH + 0.05	77
1B	1	48	SCS	3.02	TEH + 0.07	52
1B	4	40	SCS	0.86	TEH + 0.12	38
1B	4	44	MCS	1.71	TEH + 0.06	63
1B	5	42	MCS	2.15	TEH + 0	63
1B	6	12	SCS	1.37	TEH + 0.09	56
1B	6	45	SCS	1.99	TEH + 0.11	45
1B	6	47	SCS	1.53	TEH + 0.09	45
1B	17	46	SCS	1.27	TEH + 0.11	87
1B	18	41	SCS	1.13	TEH + 0.07	31
1C	1	16	SCS	1.15	TEH + 0.02	35
1C	1	29	SCS	0.89	TEH + 0.03	38
1C	1	34	SCS	0.99	TEH + 0.1	31
1C	1	37	SCI	0.66	TEH + 0.06	188
1C	1	44	SCI	1.63	TEH + 0.01	318
1C	1	45	SCS	2.15	TEH + 0.58	77
1C	2	65	SAS	2.49	TEH + 0.1	0.25
1C	3	31	SCS	1.9	TEH + 0.08	64
1C	3	34	SCS	1.98	TEH + 0.08	35
1C	3	60	SAS	4.66	TEH + 0.11	0.37
1C	4	22	SCS	2.15	TEH + 0.07	80
1C	4	33	SCI	1.07	TEH + 0.05	149
			SCI	3.04	TEH + 0.07	
1C	4	44	SAS	1.55	TEH + 0.13	0.27
1C	4	51	SCS	1.91	TEH + 0.08	42
1C	4	55	SAS	2.27	TEH + 0.1	0.24
1C	5	57	SAS	1.82	TEH + 0.1	0.21
1C	6	33	SCS	1.56	TEH + 0.07	66
1C	7	84	SCS	3.41	TEH + 0.05	70
1C	8	40	SCS	1.56	TEH + 0.02	70
1C	9	57	SCS	1.53	TEH + 0.04	38
1C	10	38	MCS	1.95	TEH + 0	73
1C	10	44	SCS	3.15	TEH + 0.02	38
1C	11	39	SCI	1.42	TEH + 0.04	98
1C	11	54	SCS	1.31	TEH + 0.05	38
1C	11	55	SCS	1.78	TEH + 0.04	38
1C	12	39	SCS	0.87	TEH + 0.03	45
1C	12	55	SCS	2.12	TEH + 0.06	69
			SCS	0.78	TEH + 0.05	
1C	14	56	SCS	2.06	TEH + 0.05	84
			SCS	0.74	TEH + 0.07	
1C	18	42	SCI	2.72	TEH + 0.03	204
1C	22	63	SCS	0.66	TEH + 0.02	56
1C	22	65	SCS	1.07	TEH + 0.06	38
1C	36	50	MAS	1.58	TEH + 0.12	0.21

SAS = Single Axial Indication – Not Repairable
MAS = Multiple Axial Indication – Not Repairable
SCS = Single Circumferential Indication – Not Repairable
MCS = *Multiple Circumferential Indication* – Not Repairable
SCI = Single Circumferential Indication – Repairable

Table 8 – SG "A" Top-of-Tubesheet SCC

SG ID	ROW	COL	ORIENTATION	VOLTS	MAX DEPTH	LOC	LENGTH
1A	9	69	Axial, ID Initiated	4.51 (200 kHz)	100%TW	TSH+0.02"	0.6"

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

Fifteen tubes were plugged during the EOC22 outage. Table 9 provides a breakdown by mechanism.

Table 9 – Number of Tubes Plugged by Degradation Mechanism

MECHANISM	SG "A"	SG "B"	SG "C"
AVB Wear	0	0	0
Foreign Object Wear	1	0	1
Tube Support Plate Wear	0	0	0
Legacy Maintenance-Related Wear	0	0	0
Legacy Pitting	0	0	0
SCC at TTS	1*	0	0
SCC at Tube End	7	0	5

*Tube SG "A" R9 C69. This tube was in-situ pressure tested and stabilized prior to plugging

f. ***Total number and percentage of tubes plugged to date***

Table 10 provides the number and percentage of tubes plugged to date.

Table 10 – Tube Plugging Percentage Summary

	Tubes Installed	Tubes Plugged To-Date
SG "A"	3,342	38 (1.1%)
SG "B"	3,342	22 (0.7%)
SG "C"	3,342	26 (0.8%)
Total	10,026	86 (0.9%)

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

Summary

There was no reportable primary to secondary SG leakage during cycle 22; therefore, the Technical Specification operational leakage performance criteria was not exceeded during this operating period.

None of the volumetric tube degradation identified in Surry Unit 1 SGs during the EOC22 outage violated the structural performance criteria; thereby providing reasonable assurance that none of these flaws would have leaked during a MSLB event.

The condition monitoring evaluation of tube end cracks under the IARC methodology, and the in-situ pressure testing of the TTS PWSCC indication provide reasonable assurance that this degradation met the Technical Specification performance criteria and would not have exceeded the leakage assumed in the limiting accident analysis.

In summary, all degradation identified during the spring 2009 inspection satisfied condition monitoring requirements for SG tube structural and leakage integrity. More detailed discussion is provided below for each degradation mechanism identified.

AVB wear

The appropriate bobbin probe technique performance data for detection and sizing of AVB wear is based on the EPRI NDE technique ETSS 96004.1. Eddy current sizing uncertainty parameters were applied to the reported 2009 depths to obtain an upper bound estimate of the limiting AVB wear flaw. This value (38.3%TW) was compared directly with the structural limit for AVB wear determined in accordance with Regulatory Guide 1.121 requirements (64%TW for rows 9 to 11, 69.4%TW for rows 12 to 46). Since the limiting upper bound depth is well below the minimum structural limit, the condition monitoring structural integrity performance criteria were not violated by AVB wear.

Non-AVB Wear Volumetric Degradation

Fourteen indications (13 tubes) of volumetric tube degradation not related to AVB wear were identified during this examination (Table 6). All but four of the indications had been identified and sized during previous examinations and were included as part of the pre-planned inspection scope for re-examination during EOC22. An eddy current signal comparison for all of these pre-planned indications confirmed that none had changed since the last inspection. However, the flaw previously reported in SG "A" R27 C84 at the hot leg baffle plate was resized with a slightly more conservative technique and the resulting depth (40%TW) necessitated plugging the tube. One of the four indications (sized 24%TW) not reported previously was also in this tube at the same location.

Of the remaining three indications not reported previously, one (SG "A" R3 C66) had a 26%TW indication attributed to foreign object wear at the 5th TSP. Upon review of the historical data for this tube, a bobbin probe indication was confirmed to be present and unchanged since the 1997 inspection. No evidence remains of the foreign object believed to have caused this indication.

The remaining two indications not reported previously (SG "C" R10 C26 and SG "C" R38 C66) are both attributed to foreign object wear by objects no longer present at the affected location.

The sizing techniques used to determine the dimensions of the flaws listed in Table 6 are also identified in the table. The sizing performance of the techniques, along with the reported flaw dimensions were used to evaluate the structural integrity of the tubes.

To perform the CM for foreign object wear or other volumetric indications, the limiting degradation size must be compared with an appropriate structural integrity limit which accounts for the material property uncertainty, model uncertainties and NDE sizing uncertainties. Since the circumferential extent of all of the indications listed in Table 6 can be shown to be <135°, it is appropriate to use the EPRI Flaw Handbook "Part-Throughwall Axial Volumetric Degradation" flaw model to evaluate the CM limit.

Figures 1 and 2 provide the 95/50 CM limit curves for flaws sized with ETSS 27901.1 and 21998.1, respectively. The CM curves represent the structural performance criteria derived by conservatively accounting for material property uncertainties, model uncertainties, and NDE depth sizing uncertainties. The uncertainties were combined using Monte Carlo techniques as described in the EPRI Integrity Assessment Guidelines.

The figures also display the length and depth of each flaw. For all but SG "C" R10 C26, the plotted dimensions are as measured by eddy current. Because the flaw in SG "C" R10 C26 was deeper than the rest, the structurally significant depth and axial length are plotted. These dimensions were determined using the methods of the EPRI Integrity Assessment Guidelines, Section 5.1.5 which employs depth profiling to determine the dimensions of an equivalent rectangular flaw. Because each flaw plotted in Figures 1 and 2 lies below the CM limit curve, it is concluded that the structural performance criteria was not exceeded by any of the evaluated flaws.

TSP wear indication in SG "A" R2 C57 reported as 14%TW X 0.29 inches axially using ETSS 96910.1. This flaw is the same depth now as it was when initially detected in 2006. Applicable NDE sizing uncertainty with respect to this flaw is that associated with ETSS 96910.1:

Total Random Sizing Uncertainty at 95% CL:	12.31%TW
Adjusted 2009 %TW:	[1.01] x [Field Call] + [4.30]

Compensating for this uncertainty yields an upper bound estimate of the 2009 depth (UB2009):

UB2009 = (1.01) x (14) + 4.30 + 12.31
UB2009 = 31%TW

This is well below the Regulatory Guide 1.121 based structural limit of 56.6%TW. On the basis of this information, it is concluded that this flaw did not exceed the Technical Specification structural performance criteria.

In summary, none of the reported non-AVB-wear volumetric flaws exceed the condition monitoring structural performance criteria set forth by the Surry Technical Specifications. Based on this it is also concluded that none of these flaws would have leaked under accident conditions.

Figure 1

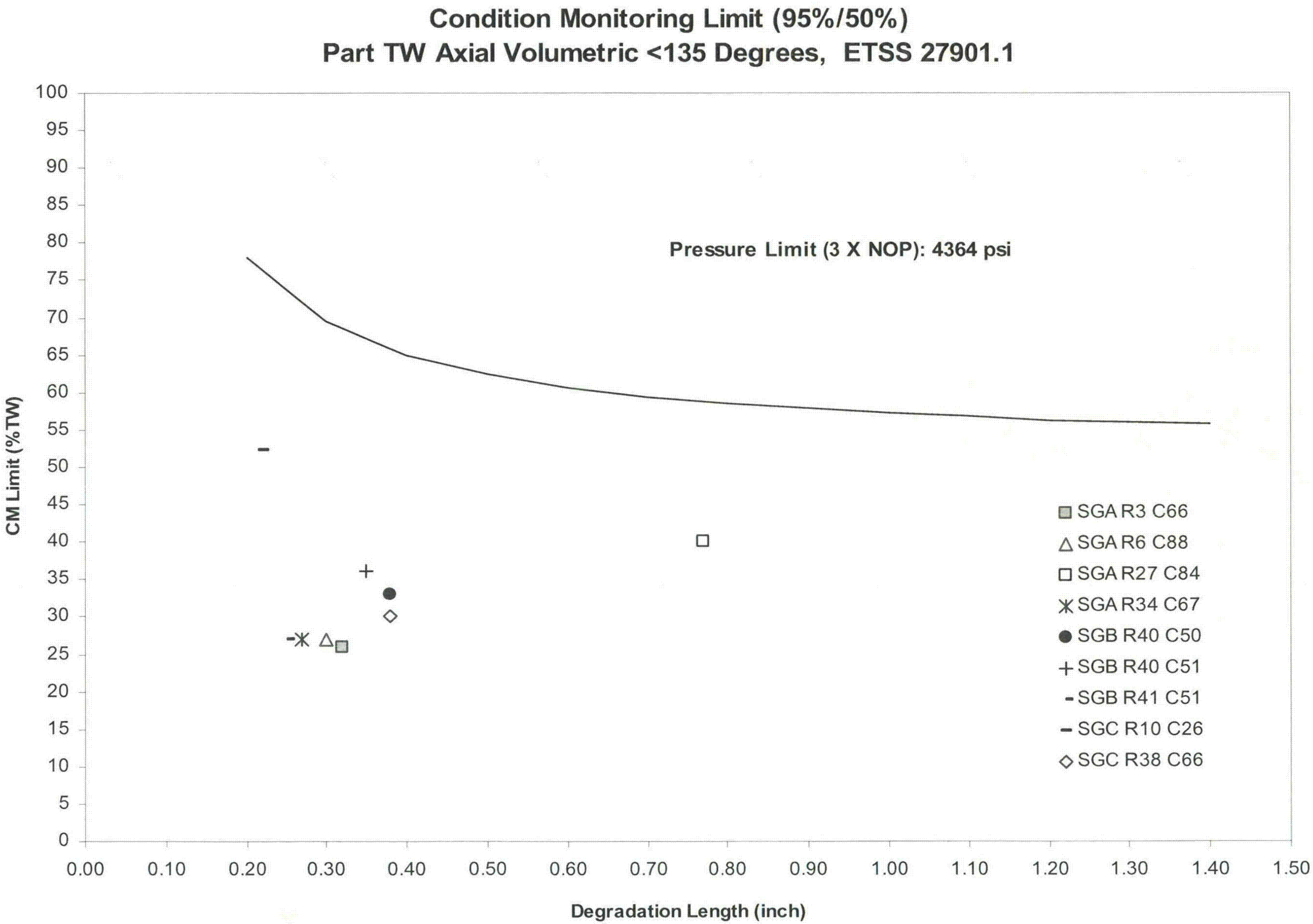
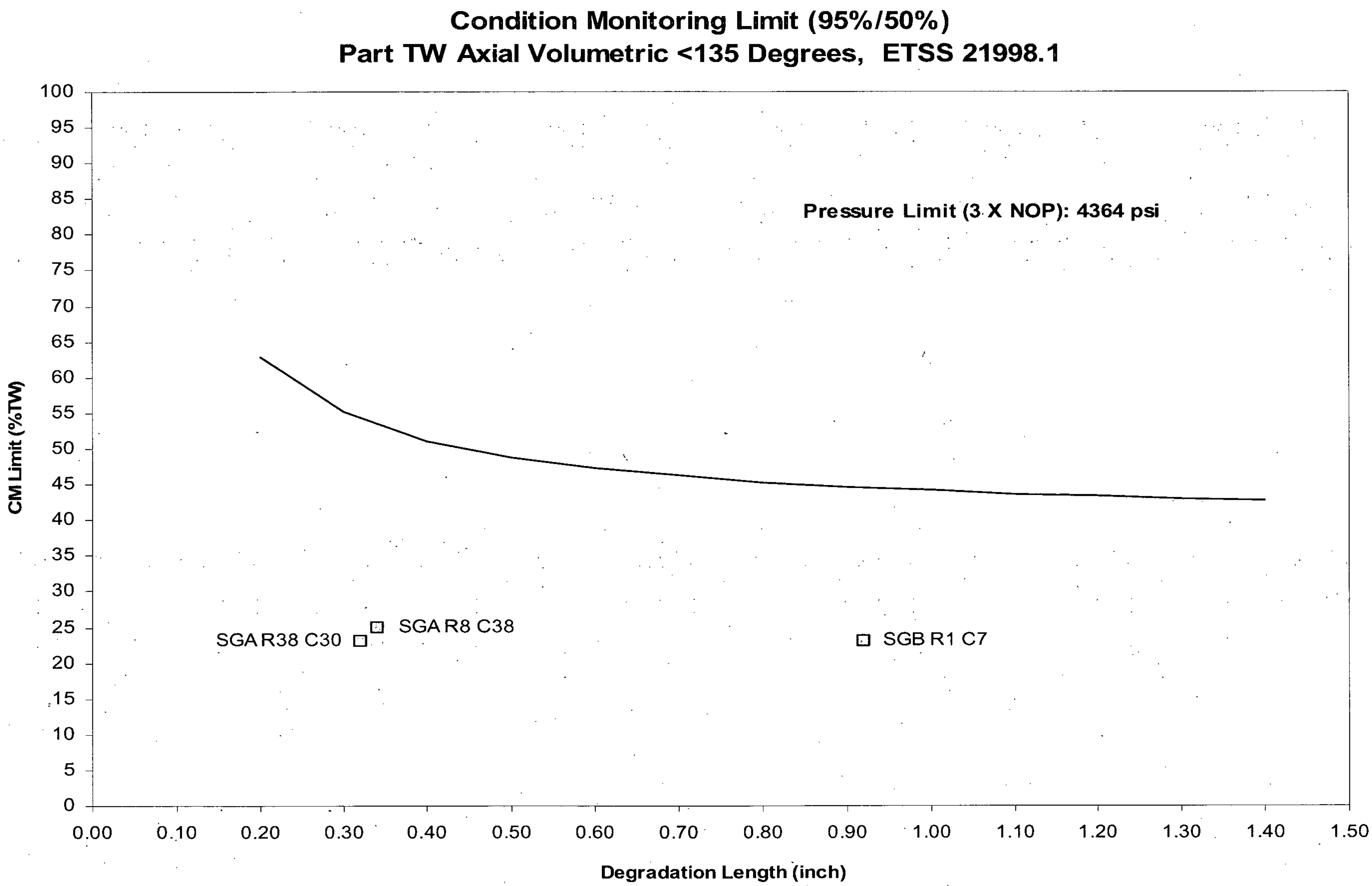

Condition Monitoring Limit (95%/50%)
Part TW Axial Volumetric <135 Degrees, ETSS 27901.1
Pressure Limit (3 X NOP): 4364 psi
CM Limit (%TW)
100
95
90
85
80
75
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
1.10
1.20
1.30
1.40
1.50
Degradation Length (inch)
SGA R3 C66
SGA R6 C88
SGA R27 C84
SGA R34 C67
SGB R40 C50
SGB R40 C51
SGB R41 C51
SGC R10 C26
SGC R38 C66

Figure 2


Condition Monitoring Limit (95%/50%)
Part TW Axial Volumetric <135 Degrees, ETSS 21998.1
Pressure Limit (3 X NOP): 4364 psi
CM Limit (%TW)
100
95
90
85
80
75
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
SGA R38 C30
SGA R8 C38
SGB R1 C7
0.00
0.10
0.20
0.30
0.40
0.50
0.60
0.70
0.80
0.90
1.00
1.10
1.20
1.30
1.40
1.50
Degradation Length (inch)

Top of Tubesheet Stress Corrosion Cracking

To demonstrate that tube SG "A" R9 C69 met the Technical Specification performance criteria, in-situ accident leakage and structural proof testing was performed in accordance with the guidelines provided in EPRI, "Steam Generator In Situ Pressure Test Guidelines - Revision 3". Leakage testing was accomplished using full tube pressurization. No leakage occurred during the accident level hold, or at any other time during the test; thereby successfully demonstrating that the tube met the Technical Specification accident leakage performance criteria. Proof testing at three times the normal operating pressure differential, adjusted for temperature and other factors relating to the test process, was performed with a bladder installed to ensure that any leakage that developed at the higher test pressure would not prevent the test apparatus from maintaining required test pressures. The tube was held pressurized at the required hold time without any difficulties and without causing rupture; thereby demonstrating that the Technical Specification structural and leakage performance criteria were met.

Tube End Stress Corrosion Cracking

Tube degradation located within the tubesheet expansion region presents no risk of burst because of the constraint provided by the tubesheet. Per the IARC Technical Specification Amendment, axial cracks within the tubesheet cannot result in tube burst or pullout. Therefore, the axial cracks identified during EOC22 do not violate CM structural requirements.

With respect to the CM structural evaluation for circumferential cracks, the key condition which must be considered is the ability of the tube-to-tubesheet joint to resist tube pull-out caused by end cap pressure loads under limiting operational and accident conditions. The IARC provides no guidance relative to the CM structural evaluation of circumferential indications which exceed the repair criteria; however, an extensive body of laboratory testing and analytical work provides the basis for concluding that none of the circumferential cracks violate the CM structural performance criteria.

It has been determined that an external retarding force of 3200 lbf. is required to prevent tube pullout under bounding operational scenarios. This value is developed based upon the load carrying capability of the remaining weld ligament of 235 degrees required by the IARC TS. It has also been determined that a tube that is severed at a distance of 0.5 inch from the tube end, and which has an expansion only from the point of sever to a point 4 inches above the tube end; has a restraining force capability of 4869 lbf for the tube in the bounding location in the bundle. All other tubes would have a greater restraining force. This restraining force exceeds the required value of 3200 lbf. An alternate approach determined the minimum contact pressure during the limiting operational and accident conditions (NOP at minimum Tavg.) at the limiting tube location in the bundle and the limiting axial location in that tube. When this conservative value was applied over the tube from TTS-1 inches to TTS-17 inches in the most conservative location, a restraining force of 8096 lbf, which far exceeds the required value of 3200 lbf, was the result. Once again, all other tubes in the bundle would exhibit a greater restraining force.

This information demonstrates that none of the circumferential tube end cracks identified in the Surry SGs during EOC22 could have resulted in tube pullout under limiting operating or accident conditions. Hence, the identified tube end cracks did not violate the Technical Specification structural integrity performance criteria.

Accident induced leakage could result from plant conditions that exacerbate existing degradation or that enhance potential leakage flow paths. The first would apply to tubing with degradation located outside the tubesheet such that an increased primary-to-secondary differential pressure could cause a tube failure or pop through during an accident. The only degradation identified in the Unit 1 SGs outside of the tube end region which could conceivably pop through during an accident was that of SG "A" R9 C69 which had an axial indication indicative of stress corrosion cracking at the TTS. However through in-situ testing, that tube was shown to be capable of withstanding limiting accident pressure differential with no leakage (discussed later). Therefore there was no degradation close to a pop through condition.

With respect to tube end cracking, the documentation supporting the IARC provides the basis for concluding that since there was no measurable operational leakage (less than 1.0 gpd) during the preceding operating cycle, tube end cracks would not have resulted in primary to secondary leakage exceeding the analyzed accident leakage during a design basis accident. Less than one gpd times the leakage factor of 2.5 associated with the IARC and tube end cracks results in accident induced leakage being less than 2.5 gpd, well below the 470 gpd limit for the limiting SG. From this discussion, there is reasonable assurance that the accident induced leakage performance criteria would not have been exceeded during a design basis accident.

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

There are no sleeves installed in the Surry Unit 1 SGs therefore, the effective plugging percentage is the same as stated in Table 10.

I. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 6.4.Q.3

The only service induced indications within the thickness of the tubesheet were those located below 17 inches below the top of the tubesheet and were characterized as primary water stress corrosion cracking (i.e., tube end SCC). None of the circumferential indications were overlapped circumferentially and no crack indications were identified in the cold leg. These results are summarized in the Table 11 below. Actual results can be found in Table 7.

Table 11 Hot Leg Tube End SCC Summary

SG	Tubes with Tube End SCC Indications	Circumferential SCC Exceeding the 94° Criteria	Circumferential SCC Exceeding the 203° Criteria	Tubes Requiring Repair Due to Tube End SCC
A	44	7	0	7
B	9	0	0	0
C	32	5	0	5

m. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the primary to secondary leakage rate observed in each steam generator (if it is not practical to assign leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one steam generator) during the cycle preceding the inspection which is the subject of the report

There was no reportable primary to secondary SG leakage during cycle 22, the cycle preceding the inspection which is the subject of this report.

n. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting steam generator

To date, there has been no reportable primary to secondary SG leakage following the completion of the Refueling Outage 22 inspection; therefore, the calculated accident leakage rate from the subject portion of the tubes is zero.

o. Following completion of a Unit 1 inspection performed in Refueling Outage 22 (and any other inspections performed in the subsequent operating cycle), for the B steam generator, the number of permeability variation indications including location and total circumferential extent

A large number of tube ends in both the hot leg and cold leg of SG "B" (1473 tubes affected) had permeability variation indications (PVNs) within 0.2 inches of the tube end. Examination of a sample using a magnetically biased probe demonstrated that the interfering signal could not be adequately suppressed. Due to the interference caused by the PVNs, the required tube end inspection could not determine which if any of the affected tubes may have cracks. As a result, Surry requested and was granted an emergency Technical Specification change to allow tubes in SG "B" with permeability indications within 1 inch from the tube end to remain in service for the next operating cycle. The technical basis for this License Amendment Request (LAR) assumes that a 360 degree through wall crack is masked by the permeability variation indication. The LAR noted that linear indications that were detected in the "B" SG would be dispositioned in accordance with the IARC criteria listed above; however, no tubes requiring plugging were identified.

The following table summarizes the total number of permeability indications reported in SG "B":

Table 12 Summary of Permeability Indications

Location	Number of Tubes	Number of Indications
Hot Leg	1056	1083
Cold Leg	1243	1260
Hot Leg and Cold Leg Combined	1473	2343

The distribution of measured circumferential extents is provided in Figure 3 below. In addition, Attachment 5 of the letter dated May 5, 2009 (Serial No. 09-295) submitted by Virginia Electric and Power Company provided details for the indications.

Figure 3

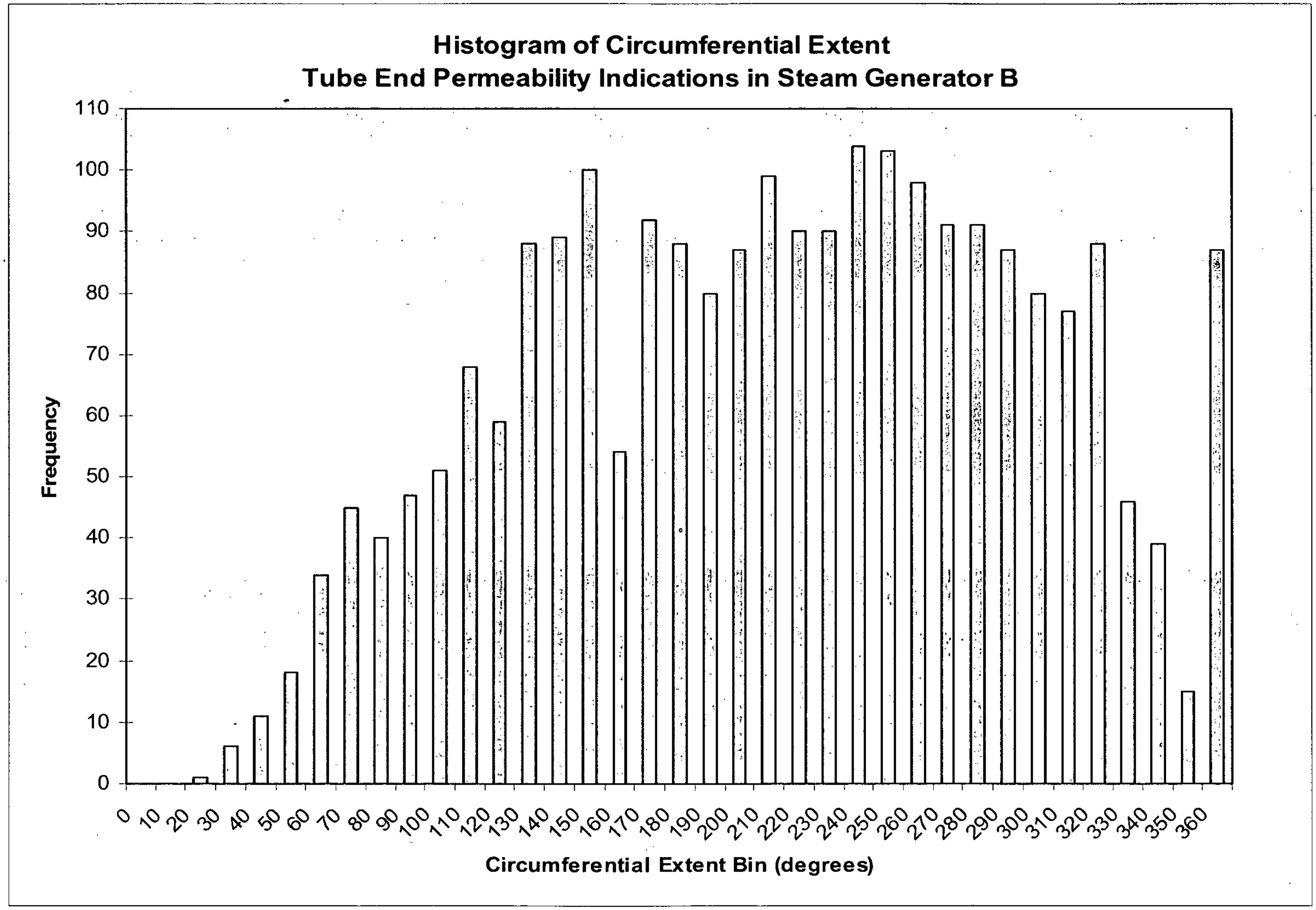

Histogram of Circumferential Extent
Tube End Permeability Indications in Steam Generator B
Frequency
110
100
90
80
70
60
50
40
30
20
10
0
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
190
200
210
220
230
240
250
260
270
280
290
300
310
320
330
340
350
360
Circumferential Extent Bin (degrees)

Table of Acronyms

AVB	Anti Vibration Bar
BLG	Bulge
BPH	Baffle Plate Hot
C or Col	Column
C/L	Cold Leg
DEP	Deposit
DNG	Ding
DNT	Dent
ECT	Eddy Current Testing
EFPY	Effective Full Power Years
FB	Fan Bar
FOSAR	Foreign Object Search and Retrieval
H/L	Hot Leg
ID	Inner Diameter
LGV	Local Geometric Variation
LPI	Loose Part Indication
MAI	Multiple Axial Indications
MBM	Manufacturing Burnish Mark
MCI	Multiple Circumferential Indications
NTE	No Tube Expansion
NQH	Non-Quantifiable Historical Indication
NQI	Non-Quantifiable Indication
OD	Outer Diameter
ODSCC	Outer Diameter Stress Corrosion Cracking
OVR	Over Roll
OXP	Over Expansion
PLP	Possible Loose Part
PTE	Partial Tubesheet Expansion
PWSCC	Primary Water Stress Corrosion Cracking
R	Row
RPC	Rotating Pancake Coil
SG	Steam Generator
SLG	Sludge
SAI	Single Axial Indication
SSI	Secondary Side Inspection
SVI	Single Volumetric Indication
TEC	Tube End Cold-leg
TEH	Tube End Hot-leg
TSC	Top of Tube Sheet Cold-leg
TSH	Top of Tube Sheet Hot-leg
TSP	Tube Support Plate
TW	Through Wall
VOL	Volumetric Indication
WAR	Wear Indication