VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNITS 1 AND 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
2006 STEAM GENERATOR INSERVICE INSPECTION REPORTS

By letters dated June 1, 2006 (Serial No. 06-446), November 30, 2006 (Serial No. 06-1024), and March 1, 2007 (Serial No. 07-0099), Virginia Electric and Power Company (Dominion) submitted the inspection results from the steam generator inservice inspections performed for Surry Power Station Units 1 and 2 during their respective 2006 refueling outages. After review of the documents listed above, the NRC staff determined that additional information was required to complete their review. The NRC's questions and Dominion's responses are provided in the enclosure.

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

Very truly yours,

G. T. Bischof
Vice President - Nuclear Engineering

Commitments made in this letter: None

Enclosure

Response to NRC Request for Additional Information Regarding 2006 Steam Generator Inservice Inspection Reports, Surry Power Station Units 1 and 2

A047

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ENCLOSURE

Response to NRC Request for Additional Information Regarding 2006 Steam Generator Inservice Inspection Reports

Surry Power Station Units 1 and 2

Virginia Electric and Power Company (Dominion)

REQUEST FOR ADDITIONAL INFORMATION REGARDING STEAM GENERATOR INSERVICE INSPECTION REPORTS FOR THE 2006 REFUELING OUTAGES

SURRY POWER STATION UNIT NOS. 1 AND 2

By letters dated June 1, 2006, November 30, 2006, and March 1, 2007, Virginia Electric and Power Company (Dominion) submitted steam generator (SG) tube inspection results from the 2006 inspections performed at Surry Power Station Unit Nos. 1 and 2. After review of these documents, the NRC staff determined that additional information was required to complete their review. The NRC's questions and Dominion's responses are provided below.

1. *Please discuss any insights that have been gained regarding the denting phenomena at the 6th and 7th tube support plates for Surry 1 and 2. Please discuss whether the size of the dents is increasing with time.*

Dominion Response

Local anomalies are distributed throughout the SG tube bundle and were caused by original manufacturing and insertion of tubes in the support plates. They are indicative of scrapes and indentations on the tubes.

While minor dent voltage changes from one inspection to the next have routinely been observed during Surry steam generator (SG) tube examinations, these changes occur in both the negative and positive directions and are indicative of non-destructive examination (NDE) measurement uncertainty. Eddy current testing (ECT) data analysis practices employed at Surry Units 1 and 2 during the 2006 tube examinations provide clear direction regarding consideration of the potential progression of dent size. Specifically, prior inspection data was reviewed for each dent identified during the current inspection to determine whether the signal was new, or, if previously identified, to determine whether the signal had changed since the previous inspection. During the 2006 examinations, only two indications at the 6^{th} and 7^{th} tube support plates demonstrated change (Unit 1, SG "A"). A follow-up +Point probe examination of both locations revealed no degradation. All identified dents were verified as having been present during the prior examination, thus confirming that no dents were newly developed. These findings indicate that no increasing trend in dent size is occurring at the 6^{th} and 7^{th} tube support plates.

2. *On Page 16 of Enclosure 1, the Figure 1 title references Examination Technique Specification Sheet (ETSS) 96810.1; however, the text on Page 14 references ETSS 96910.1. Please clarify which reference is correct.*

Dominion Response

The Figure 1 title contains a typographical error. It should read "Figure 1 – Condition Monitoring Assessment for Non-AVB Wear Volumetric Degradation – ETSS 96910.1."

3. *During the Surry 1 outage, there was extensive discussion concerning the in-situ pressure test of Tube Row 35 Column 68 in SG A. Please provide a copy of the leak rate and pressure versus time plot for this in-situ pressure test (for historical reference).*

Dominion Response

A copy of the leak rate and pressure versus time plot for the in-situ pressure test performed on Tube Row 35 Column 68 in Surry Unit 1 SG A is provided in the attachment to this enclosure. As noted on the plot, the information provided is for the second in-situ test that was performed on the subject tube. The first in-situ test attempt was aborted due to a faulty medium flow meter that required replacement prior to completing the test.

4. *On Pages 7 and 8 of Enclosure 1, Table 2 lists several tubes that had indications in 2001 that were not detected during the 2006 outage. Please provide any insight into this phenomenon and discuss any actions taken to confirm that the indications were not present in 2006. For Unit 2, there was one indication that was detected in 2002 but not reported in 2006. Please discuss whether the indication was still present (and not reportable per your guidelines) or whether there was no longer an indication at this location. If the latter is true, discuss any insights into why the indication is no longer present.*

Dominion Response

During the analysis of Surry eddy current data, locations with previously reported indications are reviewed to determine if a reportable indication is still present at that location. Anti-Vibration Bar (AVB) wear indications that were reported during a previous inspection but were not reported during the 2006 inspection fall into one of the two following categories: 1) the indication did not meet the reporting criteria in 2006, or 2) the tube was not examined during the 2006 outage because it had been previously plugged.

Of the ten Unit 1 tubes with prior indications that were not reported in 2006, eight had been plugged during the prior examination and were therefore not inspected in 2006. The remaining two tubes (SGAR32C66 and SGAR41C32) contained wear indications that were sized slightly above the 10% throughwall (TW) reporting criteria in 2001 and were present in 2006 but below the 10% TW reporting criteria. This occurs as a result of normal ECT depth measurement variability from one inspection to another.

In Unit 2 there were two tubes with AVB wear indications reported in 2002 that were not reported during the 2006 inspection. One of the two had been plugged in 2002 and was therefore not inspected in 2006. The indication in the other tube was present but not reportable in 2006, again due to ECT depth measurement variability.

5. *Please discuss the extent to which the non-anti-vibration bar (AVB) volumetric indications in Surry 1 and 2 were detected with the bobbin coil. If all the indications weren't detected by bobbin, discuss the basis for not performing 100% rotating probe examinations on both the hot-leg and cold-leg. If a turbo mix was used (e.g., near the top of the tubesheet), please discuss the extent to which the turbo mix identified the area with loose parts or loose parts damage.*

Dominion Response

The tables provided in Enclosures 1 and 2 of Dominion's March 1, 2007 letter have been modified to indicate whether the flaws were detected with the bobbin probe. The modified tables are provided below.

Unit 1 2006 -- Non-AVB Wear Volumetric Degradation

						ETSS 96910.1			ETSS 21998.1			
SG	Row	Col	Location	Axial Length (in)	Circ. Length (in)	Max Depth (%TW)	Structural Depth (%TW)	Structural Length (in)	Max Depth (%TW)	Structural Depth (%TW)	Structural Length (in)	Detected with the Bobbin Probe?
A	35	68	@TSH	0.83	0.92	65	60.4	0.43	na	na	na	Yes
A	35	69	@TSH	0.49	0.65	49	44.3	0.35	84	73.1	0.34	Yes
A	36	68	@TSH	0.54	0.52	31	26.3	0.34	54	46.1	0.37	Yes
A	34	67	@TSH	0.26	0.34	na	na	na	22	20.2	0.20	No
A	5	88	@TSH	0.42	0.53	na	na	na	40	36.1	0.34	Yes
A	6	88	@TSH	0.30	0.40	na	na	na	17	16.3	0.16	No
A	8	38	@TSH	0.32	0.37	na	na	na	20	17.5	0.2	No
A	27	84	@ Top of BPH	0.40	0.39	na	na	na	29	24.6	0.26	Yes
A	36	49	@TSH	0.32	0.45	na	na	na	41	27.8	0.23	No
A	36	50	@TSH	0.40	0.48	na	na	na	43	37.1	0.34	No
A	2	57	TSP Wear @6C	0.14	0.37	14	12.3	0.09	na	na	na	Yes
A	38	30	@TSC +2"	0.31	0.42	na	na	na	17	15.9	0.25	Yes
C	15	62	@3H	0.32	0.42	na	na	na	27	na	na	Yes
C	38	62	@1H	0.34	0.37	na	na	na	32	na	na	Yes

Unit 2 2006 -- Non-AVB Wear Volumetric Degradation

						ETSS 96910.1			ETSS 21998.1			
SG	Row	Col	Location	Axial Length (in)	Circ. Length (in)	Max Depth (%TW)	Structural Depth (%TW)	Structural Length (in)	Max Depth (%TW)	Structural Depth (%TW)	Structural Length (in)	Detected with the Bobbin Probe?
A	17	16	@TSH	0.36	0.56	na	na	na	20	na	na	No
A	18	16	@TSH	0.31	0.39	na	na	na	19	na	na	No
A	32	27	@TSC	0.29	0.25	na	na	na	28	na	na	No
A	33	27	@TSC	0.42	0.36	na	na	na	28	na	na	No
A	34	26	@TSC	0.42	0.47	19	na	na	36	na	na	No
A	34	27	@TSC	0.57	0.67	42	38	0.25	72	65	0.23	Yes
A	35	27	@TSC	0.52	0.53	31	26	0.27	49	42	0.31	Yes
A	40	28	@TSC	0.44	0.48	18	na	na	35	na	na	No
A	40	29	@TSC	0.47	0.47	19	na	na	36	na	na	Yes
A	41	29	@TSC	0.57	0.53	42	37	0.28	70	60	0.29	Yes
A	41	27	@TSH	Significant tube end damage. Affected axial length approximately 1.75" as indicated by RPC with most severe circumferential involvement of approximately 0.9".								No*

*Initially detected during primary channel head visual examination. Clearly visible in bobbin data.

As indicated, two of the volumetric flaws that were identified only with the rotating probe (SGAR36C49 and SGAR36C50 in Unit 1) had a maximum throughwall depth exceeding the 40% plugging limit and therefore caused SG "A" to enter into Technical Specification inspection results category C-2. Consequently, a 20% top of tubesheet rotating probe scope expansion was implemented in both the hot leg and cold leg of SG "A". No additional flaws were identified as a result of this scope expansion; hence, no additional rotating probe examinations were required to be performed. All other flaws identified in the tables above as having not been detected with the bobbin probe were less than 40% TW and therefore required no ECT inspection scope expansion.

The turbo mix is an integral part of the process used to detect foreign object wear in the Surry steam generators. As such, a determination of the extent to which the turbo mix may be credited for detections that would otherwise not have been possible is not available from the results of the Surry inspections. Based on the experience of other utilities, the vendor and Dominion's Eddy Current Level III, it is clear that the turbo mix improves the ability of the bobbin probe to detect these conditions when they occur close to the tubesheet.

6.a *Figures 1 and 2 of Enclosure 1 and Figures 3 and 4 of Enclosure 2 to your March 1, 2007, letter provide condition monitoring curves for volumetric degradation (other than wear at the anti-vibration bars). It is the NRC staff's understanding that the curves in these figures include eddy current uncertainty. However, the differences in these curves are not significant despite the discussion*

in the text of the report that sizing of flaws using ETSS 21998.1 is very conservative for flaws greater than approximately 0.25-inch.

Dominion Response

The subject condition monitoring (CM) curves include NDE uncertainty allowances that are consistent with the NDE uncertainty parameters documented in EPRI's Examination Technique Specification Sheets (ETSSs) 96910.1 and ETSS 21998.1. The uncertainty parameters for the two techniques are similar to each other for the specific types of degradation that they were designed to address. The conservatism of ETSS 21998.1 is not reflected in the ETSS parameters because ETSS 21998.1 is intended to be used to size small volume pits and is increasingly conservative as the volume of the flaws increases. For pits, ETSS 21998.1 provides reasonably accurate size estimates just as ETSS 96910.1 provides reasonably accurate size estimates for larger volume flaws. The conservatism associated with ETSS 21998.1 is reflected not in the CM curve itself but in the indicated depths of the flaws plotted in the figures enclosed in the March 1, 2007 letter.

6.b *Although two data points supporting the over-estimation of flaw sizes using ETSS 21998.1 were provided in Enclosure 2 to your March 1, 2007, letter, please provide any additional data that supports your conclusion that ETSS 21998.1 is very conservative for flaws greater than approximately 0.25-inch in length. In addition, please provide your basis for concluding that ETSS 96910.1 is appropriate for sizing flaws greater than 0.25-inch (including a discussion of the uncertainties associated with sizing with this technique). Please discuss how the uncertainties vary with flaw size (axial length, circumferential extent, and depth).*

Dominion Response

A fundamental characteristic of the eddy current NDE method is that for a given flaw depth a larger volume of missing material will generate a larger amplitude response. Given two flaws with exactly the same depth, the flaw with the greatest volume will produce the largest amplitude eddy current response.

ETSS 21998.1 is a rotating +Point probe analysis technique which employs an amplitude-based calibration curve to develop estimates of flaw depth. The calibration curve is formed by measuring the response of the probe to flat bottom drilled holes of various depths contained in a calibration standard developed specifically for ETSS 21998.1. The drilled holes are only 0.0625 inch in diameter. Because ETSS 21998.1 employs an amplitude-based calibration curve, a flaw whose diameter is greater (i.e., more material missing) than that of the calibration flaws will produce a larger amplitude signal and will appear, based on the calibration curve, to be deeper than it actually is. For this reason, the documentation describing ETSS 21998.1 (available at www.epriq.com) provides a statement cautioning the user that depth estimates for flaws greater than 0.25" long will be conservative. This is further illustrated by the data provided in Enclosure 2 and referenced in this question. No other data is available.

ETSS 96910.1 is also an amplitude-based sizing technique. However, for this technique the AVB wear calibration standard wear scars are used to establish the calibration curve. Since the AVB wear scars have larger axial and circumferential dimensions than those used to calibrate ETSS 21998.1, the resulting calibration curve is appropriate for sizing larger flaws. Uncertainty information as a function of flaw size is not available for either of these techniques

6.c *The NRC staff notes that Figures 1 and 2 list the structurally significant length and depth. Although the use of the structurally significant length and depth is probably appropriate for assessing the structural integrity of the flaw, please confirm that the non-destructive examination uncertainties are also based on the structurally significant dimensions rather than the actual dimensions of the flaw (i.e., was the qualification data assessed using actual dimensions or structurally significant dimensions of the flaw). It may be useful to provide the actual flaw depth, the measured flaw depth, the actual structurally significant depth and length, and the measured structurally significant depth and length for the qualification samples. If any data exists that provides destructive examination results associated with flaws sized by both ETSS 21998.1 and ETSS 96910.1, such data may be useful in assessing the uncertainty associated with these techniques.*

<u>Dominion Response</u>

The evaluation of the uncertainty of the subject techniques is provided in their respective ETSS documentation which is available for review at www.epriq.com. These documents provide the as-built depth measurements, as well as the analysis technique's depth estimate, for each qualification flaw. The documented uncertainty parameters for both techniques are based upon actual flaw dimensions as opposed to structurally significant dimensions. Structurally significant dimensions are not currently available for the qualification flaws.

6.d *In addition to the above, please provide the size estimates for all volumetric flaws (other than wear at the anti-vibration bars) using ETSS 96910.1 and ETSS 21998.1.*

<u>Dominion Response</u>

All of the size estimates developed during the 2006 inspections are provided in the tables included within Enclosures 1 and 2. As noted, not all flaws were sized using both techniques. Generally, if the structural integrity of a flawed tube could be verified using the more conservative ETSS 21998.1 depth estimates, or if it was determined that a particular technique was more appropriate for sizing a flaw; no additional sizing was performed for that flaw.

7. *Cracking has been observed in units with thermally treated Alloy 600 tubes at the tube-ends near the tube-to-tubesheet welds. This includes cracking of the welds that penetrated into the parent tube. Please discuss the extent to which the tube end area (including the tack expansion and the parent tube near the tube-to-tubesheet weld) was examined during your inspections of Surry 1 and 2. If no inspections were performed, please discuss the basis for not examining this area.*

Dominion Response

The examination scope implemented at both Surry units during 2006 was comprised of a bobbin probe inspection of all tubes in the inspected SGs, which included the entire tubesheet expansion in both legs. The bobbin data were used to identify OXPs exceeding 18 volts within the region from two inches above the tube end to the top of the tubesheet. This inspection was augmented with a rotating +Point probe examination of the largest voltage OXPs reported on the hot leg. The 20% top of tubesheet rotating probe inspection also included $\geq$ three inches of the tube expansion within the tubesheet. This provided the added benefit of sampling the tube expansion without regard to the presence or size of OXPs. As a result, a few additional OXPs located within three inches of the top of the tubesheet were also examined. However, no rotating probe examinations were performed in the lower two inches of the tube.

An inspection in the bottom two inches was not considered to be necessary because the expected time to develop cracking in that region has not yet been reached. Surry's low operating temperature provides the basis for the conclusion that cracking within the tubesheet region would not have been expected at the time of the 2006 refueling outages. This is discussed in more detail in the response to Question 11 below. This conclusion is also supported by comparing the results of the examinations that were performed at Surry with the findings of the plant that identified tube end cracking (i.e., Catawba 2). Catawba 2 identified not only tube end cracking but also identified cracking elsewhere within the tubesheet expansion. The initial Catawba 2 inspection scope had excluded the tube end, and the scope was expanded to include the tube end after identifying cracks within the upper portion of the tubesheet. At Surry, no evidence of cracking has been identified at any location within the tube bundle, including the tubesheet expansion transitions and OXPs, at either unit.

Cracking was not expected at the time of the 2006 outages; furthermore, cracking in the uninspected region (i.e., lower two inches), if it occurred, would have no safety consequence. The bottom two inches of the tube expansion is located below 19 inches of expanded tubing. Tube rupture at this location is precluded due to the reinforcing effect of the tubesheet. An "H*" evaluation to quantify the ability of the Surry hydraulic expansion to resist pull out and leakage under limiting conditions has been performed. This evaluation concludes that tube defects of any magnitude will have no effect on the tube pull out resistance under bounding loading conditions with appropriate factors of safety [specifically, end cap load produced by 1.4 x Main Steam Line Break (MSLB) pressure differential] provided the defect is located more than 8.5 inches below the top of the expansion. The evaluation also concludes that, provided the defect is located

more than 17 inches below the top of the expansion, the primary to secondary leak rate under MSLB conditions will be less than twice the leak rate which occurs during normal operation.

Assuming the plant operates with leakage at the normal operating leakage limit [150 gallons/day (gpd)], and assuming all leakage originates from within-tubesheet defects located below the 17 inch limit, a MSLB event would result in no more than 300 gpd in the faulted loop. Since this value is less than the 500 gpd faulted loop value assumed in the accident analysis, defects below the 17 inch location will not cause the accident leakage performance criteria to be exceeded. This evaluation demonstrates that even if defects were to occur in this region of the tube expansion, they would have no safety consequences. It is for this reason that Surry chose to focus the augmented rotating probe examinations in the upper 19-inches of the tubesheet.

8. *On Page 8 of Enclosure 2, the text states 60 bulges were identified in SG A of Surry 2. Please discuss the cause of these bulges and the three bulges identified on Page 10 of Enclosure 1 for Surry 1.*

Dominion Response

A review of historical eddy current data performed as part of the tube inspections have revealed no evidence of an increasing trend in size nor evidence of new bulges. This suggests that the bulges occurred during the fabrication of the steam generators. While the specific cause is unknown, no evidence of corrosion or other tube degradation has been identified to date in any of the Surry bulges.

9. *Please discuss the differences between an over-expansion (OXP) and a bulge (OXP within the tubesheet, over-expansion (OVR) above tubesheet). In addition, discuss the total population of OXPs and bulges (if bulges reported in the tubesheet region) in the hot leg of SGs A and C in Surry 1.*

Dominion Response

OXP is the reporting code assigned to a local tube diameter increase (i.e., a bulge) within the hydraulic tubesheet expansion from the tube end plus two inches through to the top of the tubesheet. OXPs were caused by the tubesheet hole drilling and tube expansion processes employed during steam generator fabrication. OVR is the reporting code assigned to an area of the tube that was hydraulically expanded more than 0.3 inches above the top of the tubesheet during original steam generator fabrication. The table below summarizes the total population of hot leg OXPs and OVRs identified in Surry Unit 1 SGs A and C.

OXP/OVR Population Summary

(tubes/indications)	SG A	SG C
Hot Leg OXP	200 / 282	330 / 421
Hot Leg OVR	1 / 1	0 / 0

10. *What is the reporting threshold for an overexpansion, either OXP or OVR, at Surry 1 and 2?*

Dominion Response

The reporting threshold for over-expansions (OXP) is 18 Volts peak-to-peak on the 400 kHz differential channel.

11. *Please discuss whether the cracking that occurred in OXPs and bulges at other units were preferentially located in "larger" OXPs or bulges. If the cracking at these other units was not biased to the larger OXPs or bulges, and a significant number of OXPs or bulges were not inspected throughout the reported voltage range for these locations at Surry, discuss the potential that cracking could be occurring and summarize your tube integrity assessment for these uninspected locations.*

Dominion Response

The limited number of industry incidences of cracking in tubesheet OXPs precludes a definitive correlation between OXP voltage and crack susceptibility. Because of the absence of a large database of failures to statistically base a correlation, only areas considered to be most likely to develop cracking can be identified. The limited cracking which has been identified within the tubesheet at overexpansion locations has been circumferentially oriented. To crack circumferentially, the tube's dominant residual stress must, by definition, be axially oriented. Within a concentric or partially concentric overexpansion, residual axial stress will be proportional to the diameter gradient moving axially along the tube (i.e., the abruptness of the geometry). A more abrupt geometry would be expected to possess larger axial stress. Since the ECT bobbin probe operating in the differential mode produces a signal amplitude that is proportional to the diameter gradient, it is reasonable to conclude that there should be a correlation between the magnitude of the ECT signal and the level of residual axial stress, and, hence, crack susceptibility. Based on this reasoning, Surry has performed rotating probe examinations focused on the largest voltage OXPs.

Vogtle Unit 1 and Catawba Unit 2 had operated 16.2 effective full power years (EFPY) and 14.7 EFPY, respectively, when the initial indications of OXP cracking were identified. Because both of these units operate with considerably higher hot leg

temperatures (Vogtle 1: 618°F; Catawba 2: 615°F) than Surry's 605°F, the equivalent operating time of the affected plants would be significantly longer at Surry's lower temperature. Accounting for this temperature difference, Surry would not expect to detect similar indications before approximately 22 to 27 EFPY. At the time of the most recent inspection (2006), Surry Unit 1 had operated for 19.5 EFPY and Surry Unit 2 had operated for 20.7 EFPY. As such, widespread OXP cracking is very unlikely to have occurred at this point in time. Neither Surry unit will reach the lower end of this range prior to its next inspection.

12. *Please confirm no degradation was identified during your examination of the over-expansions (OVRs) in Surry 1.*

<u>Dominion Response</u>

No degradation associated with OVRs has been identified during any Surry Unit 1 or Unit 2 tube inspections performed to date.

13. *You indicated that you would continue to perform visual examinations of the plugs in the tube in Row 41 Column 27 of SG A and that these examinations would reveal whether significant tubesheet corrosion was occurring. Please discuss whether you plan to continue to monitor the channel head damage to confirm that the extent of corrosion is consistent with your expectations.*

<u>Dominion Response</u>

Visual examination of the channel heads will continue to be performed during outages in which SG primary work is performed. The identified channel head degradation will be monitored as part of this process.

14. *Several pit-like indications were detected and not plugged during the 2006 outage at Surry 1. Please discuss your basis for leaving these indications in service. Include in your response the results from tube pulls that confirm the indications are pits and provide the eddy current sizing qualification data for pits. Please refer to the letter that the NRC sent to Mr. J. P. O'Hanlon on August 23, 1999.*

<u>Dominion Response</u>

The subject tubes were not pulled and examined destructively. The decision to categorize the indications as "pit-like" was based on the NDE response and the knowledge gained from prior tube pulls, ultrasonic testing, and rotating probe data for similar indications.

While the pit-like indications identified during the 2006 Unit 1 outage had not been previously identified, a review of historical eddy current data confirmed that the signals were present during the previous examination (2001) and remained unchanged since that time. This data continue to support the conclusion, provided during previous communication with the NRC, that the process which generated the Surry pits is inactive.

As discussed earlier, +Point probe technique ETSS 21998.1 is qualified to size pit-like indications. As noted in Table 3 of Enclosure 1 to our March 1, 2007 letter, the maximum depths of the subject indications were well below the 40% TW plugging criteria; therefore, the tubes were left inservice. In the absence of an active degradation process, there is reasonable assurance that these flaws will not progress to exceed the SG Program performance criteria prior to the next inspection in 2009.

15. *Please discuss whether the inspection data acquired for the permeability variation indications that were plugged was adequate to determine whether the area may have had a significant flaw. If not, please discuss how tube integrity was assessed at these locations (e.g., in-situ testing).*

Dominion Response

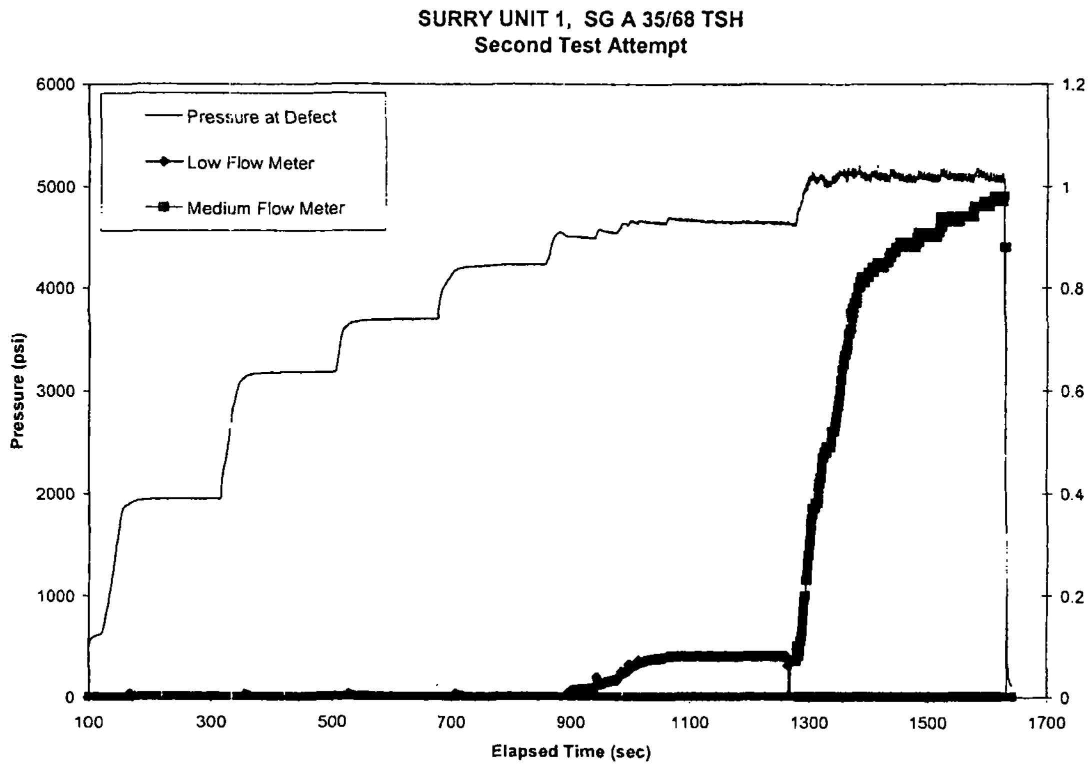
The tubes in question were conservatively and preventatively removed from service to eliminate any future concern about a potential reduction in the probability of detection (POD) should an active corrosion process eventually develop in the Surry SGs. There has been no evidence resulting from any of the Surry SG tube inspections performed to date, including the examinations performed in the tubes that were preventively plugged, that would suggest that degradation existed in these tubes.

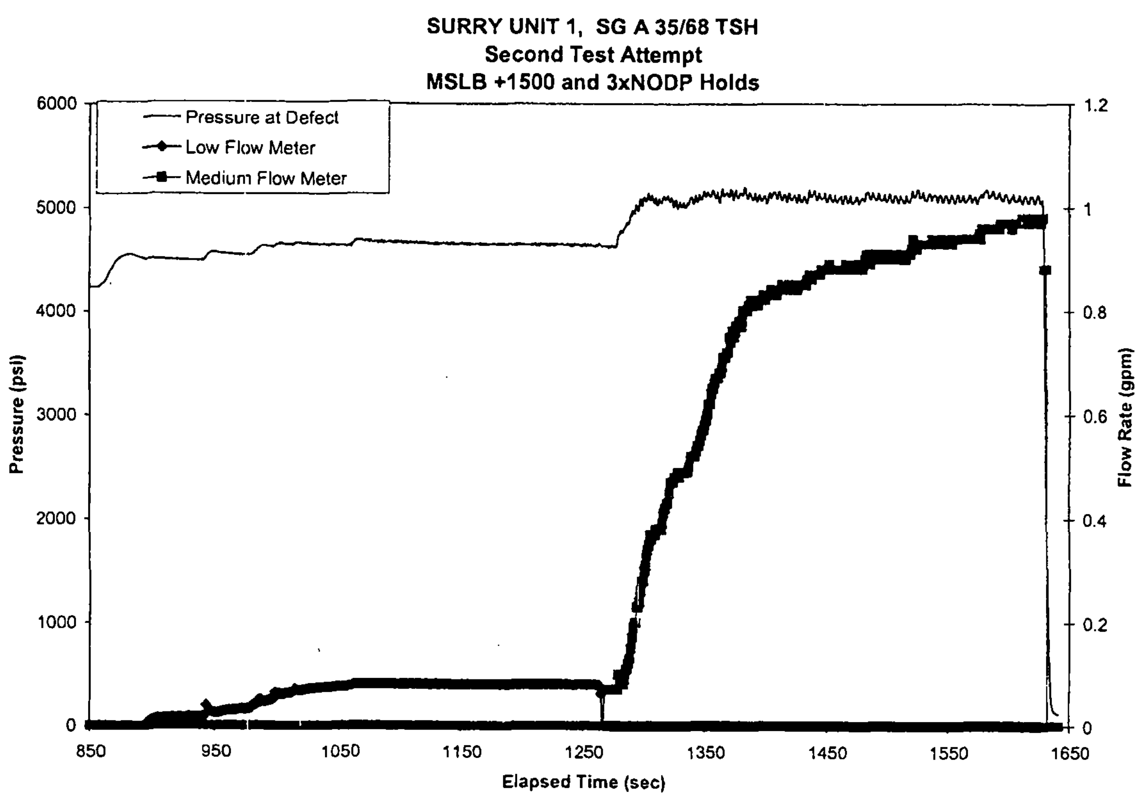
ATTACHMENT

Leak Rate and Pressure versus Time Plot for the In-situ Pressure Test Performed on Tube Row 35 Column 68 in the "A" Steam Generator

Surry Power Station Unit 1

Virginia Electric and Power Company
(Dominion)


SURRY UNIT 1, SG A 35/68 TSH
Second Test Attempt
Pressure at Defect
Low Flow Meter
Medium Flow Meter
Pressure (psi)
Flow Rate (gpm)
Elapsed Time (sec)
6000
5000
4000
3000
2000
1000
0
1.2
1
0.8
0.6
0.4
0.2
0
100
300
500
700
900
1100
1300
1500
1700


SURRY UNIT 1, SG A 35/68 TSH
Second Test Attempt
MSLB +1500 and 3xNODP Holds
Pressure at Defect
Low Flow Meter
Medium Flow Meter
Pressure (psi)
Flow Rate (gpm)
Elapsed Time (sec)
6000
5000
4000
3000
2000
1000
0
1.2
1
0.8
0.6
0.4
0.2
0
850
950
1050
1150
1250
1350
1450
1550
1650