VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

August 2, 2006

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.	06-534
NL&OS/GDM	R2
Docket No.	50-281
License No.	DPR-37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT NO. 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
STEAM GENERATOR TUBE INSERVICE INSPECTION REPORTS FOR THE 2005 REFUELING OUTAGE

Virginia Electric and Power Company (Dominion) submitted the most recent steam generator tube plugging report for Surry Power Station Unit 2 in a letter dated May 31, 2005 (Serial No. 05-339) and the annual steam generator report for Surry Units 1 and 2 in a letter dated February 28, 2006 (Serial No. 06-174). During their review of these two documents, the NRC determined that they required additional information to complete their review. In a letter dated June 20, 2006, the NRC requested additional information regarding the two reports noted above. Dominion's response to the thirteen questions included in the NRC's request is provided in the attachment.

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

Attachment

cc: U. S. Nuclear Regulatory Commission
Region II
Sam Nunn Atlanta Federal Center
61 Forsyth St., SW, Suite 23 T85
Atlanta, Georgia 30303-8931

Mr. S. R. Monarque
NRC Project Manager
U. S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Mail Stop 8G9A
Rockville, Maryland 20852

Mr. S. P. Lingam
NRC Project Manager
U. S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Mail Stop 8G9A
Rockville, Maryland 20852

Mr. N. P. Garrett
NRC Senior Resident Inspector
Surry Power Station

Mr. R. A. Smith
Authorized Nuclear Inspector
Surry Power Station

ATTACHMENT

Response to NRC Request for Additional Information

Steam Generator Tube Inservice Inspection Reports for the 2005 Refueling Outage

Surry Power Station Unit 2
Virginia Electric and Power Company
(Dominion)

Response to NRC Request for Additional Information

Surry Unit 2 Steam Generator Tube Inservice Inspection Reports for the 2005 Refueling Outage

NRC Question No. 1

Six tubes in Steam Generator (SG) B were examined with a +Point™ probe as part of an emergent examination from secondary side inspection at the top of the tubesheet in SG C. A visible scratch (shallow volumetric flaw) was observed on Tube Row 1 Column 2 (R1C2) of SG B with a percent through-wall less than 5 percent. The licensee named three possible causes for the scratch: (1) presence of a possible foreign object, (2) fabrication process, or (3) wrapper plate cruciform removal. Please discuss how the wrapper plate cruciform removal program could have affected the tube in R1C2. In addition, it was indicated that this indication was not present in previous eddy current data most likely due to its small size. Please discuss whether past videos of visual inspections were reviewed and if this indication was present.

Dominion Response

Regarding item 3 of the possible causes, "wrapper plate cruciform removal" was included because the modification to the inside edges of the "+" shaped wrapper opening to remove an interference occurred during the 1993 outage. In the process of removing these edge pieces after the grinding process, a piece of removed material could have been dropped in the generator and traveled down to the tubesheet area. These openings are approximately one foot above the tubesheet. Typically, minimum water levels are maintained during this type of work activity so little damping effect would have occurred had the piece been dropped, and, consequently, could have caused the tube to be scratched or dinged. All pieces that were removed from the wrapper were accounted for, and none remained in the steam generators in accordance with routine foreign material accountability. Past video inspections were lacking in detail and inconclusive in this area, and therefore nothing had been observed during previous inspections. The recent inspection provided clearer viewing in this area and hence revealed an apparent "scratch".

NRC Question No. 2

Results of the emergent examination in SG B were not discussed in the 15-day SG tube plugging report since no tubes were plugged as a result of the inspections. Therefore, provide the basis for the following statement made on page 4 of the annual SG inspection report, dated February 28, 2006. "The required report on the plugged tubes was supplied in the 15-day plugging report previously submitted to the NRC, with the following conclusion: Minimal wall degradation was observed on the tube with the visible scratch on the "B" steam generator and none was observed on the surrounding tubes."

Dominion Response

The "B" steam generator examination results should not have been referred to in the 15-day plugging report since no tubes were plugged in that generator. The statement should have read as follows:

"The required report on the plugged tubes was supplied in the 15-day plugging report previously submitted to the NRC for the "C" steam generator. The Condition Monitoring and Operational Assessment documents the inspection conclusions for the "B" steam generator that minimum wall degradation was observed on the tube with the visible scratch and none was observed on the surrounding tubes."

NRC Question No. 3

Table 9 in Section 2.1.4 of the February 28, 2006, submittal, compared noise measurement values for SG B to the examination technical specification sheet (ETSS) noise measurement values. Please clarify whether this data is from SG C since most examinations during this outage were in SG C. If not, please discuss why a comparison of the noise values for SG C and the ETSS noise measurement values were not included in this section.

Dominion Response

This tabulation should not have been included since it was for the "B" steam generator and had been previously reported. This type of data review was designed to supplement the data screening already included in data quality verification programs in the vendor data acquisition system. Similar benchmarking efforts have been performed at a number of previous inspections during the course of the outage inspection process. This data confirmed that noise thresholds were appropriate for the inspection techniques used. Starting with the spring 2005 Unit 2 outage, it was elected to use previous outage data for noise evaluations in preparation of the required EPRI Appendix H documentation package; therefore, a comparison of the noise values for SG C and the Eddy Current Technique Sizing Sheet (ETSS) noise measurement values was not performed during the Unit 2 outage. This review is conducted prior to each outage in preparation for the inspections. The review verifies that the average noise values are acceptable when compared to values documented in the EPRI technique qualification database.

NRC Question No. 4

On Page 1 of the annual report it was indicated that Tube R25C9 in SG C had a measured wall penetration of 19 percent; however, as indicated in Table 3, Page 7 of the annual report, this tube was indicated to have a measured wall penetration of 12 percent. Please clarify this apparent discrepancy.

Dominion Response

The 19% reported on page 1 should have read 12% as reported in Table 3 where the anti-vibration bar (AVB) wear growth projections are provided. Therefore, no change to growth projections on tubes remaining in service is necessary.

NRC Question No. 5

Given that most of the indications of imperfections detected listed in the table on Pages 1 and 2 of the annual report were not detected with a bobbin probe, why was a 100-percent top-of-tubesheet inspection not conducted? In addition, discuss how this was factored into the operational assessment.

Dominion Response

It is assumed that the RAI reference to "most of the indications" is associated with the tubes with top-of-tubesheet indications, since the AVB indications were identified with the bobbin probe. The addition of rotating coil inspections at the top-of-tubesheet referred to in the RAI were considered but deemed not to be necessary for several reasons as discussed below:

- The scope of the rotating coil inspections at the hot leg top-of-tubesheet was already a 70% sample. This represents a significant sample beyond any required expanded sample set for a volumetric indication.
- Legacy foreign material that is identified in previous inspections and cannot be removed, as well as tubes that are not removed from service are investigated in future inspections. These inspections are typically conducted even if no wear indication is observed during the previous inspection and will typically be placed on the inspection list for top-of-tubesheet rotating coil probing. In the case of the 2005 inspection in the "C" generator, material identified from previous outage tube lane and annulus visual inspections had been removed. Hence, no special eddy current inspections for this cause were necessary.
- Hot leg and cold leg side inner-bundle video inspections were conducted, i.e., camera passes down the tube columns out to the bundle periphery. Some twenty-three (23) columns on the hot leg side and seven columns on the cold leg side were investigated. When any suspect material was found, other tubes in the immediate area were also investigated by video in adjacent rows and columns. In the case where an eddy current indication was called bounding, tube eddy current inspections were conducted and visual investigations were made in the affected tube area to assist in appropriate disposition.
- Enhanced scrutiny of bobbin signals was conducted across the hot and cold leg top-of-tubesheet edge with multiple signal mixes. The bobbin inspection scope on the scheduled generator is 100% of the remaining open tubes. The enhanced scrutiny and full sample scope improved the probability of detection of significant wear indications. These bobbin volumetric indications per analysis protocol would be

investigated with a rotating probe for characterization and sizing. The results of the subject inspection indicated that all but one of the greater than 40% through-wall (TW) indications that were sized by the conservative ETSS 21998.1 method were initially detected with the bobbin. The one tube that was not detected by bobbin was a 25% TW wear indication sized by the ETSS 96910.1 rotating coil sizing technique.

Regarding the question on how the results were factored into the Operational Assessment, the discussion provided in Section 3.3 of the annual SG report addressed this issue and is a direct excerpt from the assessment.

NRC Question No. 6

On Page 9 of the annual report, it was indicated that the U-bend region of all tubes in Rows 8 and lower were evaluated for the unique "Seabrook" signature. Please discuss what evaluations, if any, were performed in the higher row tubes to identify tubes with potentially higher residual stresses.

Dominion Response

Based on an EPRI Interim Guidance Letter, in late 2004 the recommended analysis approach for large radius U-bends was to evaluate the outer row tubes for potentially higher material stress conditions. This evaluation was conducted. The identified tubes, referred to as 2 SIGMA tubes, were included since the bobbin program included 100% of the tubes. The bobbin probe is appropriately qualified to detect the referenced "Seabrook" type indications, i.e. outer diameter stress corrosion cracking/intergranular attack (ODSCC/IGA) at tube supports. No degradation of this type was identified during this inspection. As an additional measure, a sample of 2 SIGMA tubes was inspected by rotating coil in the tube areas where other potential elevated stress conditions may exist from tube geometry artifacts, i.e. top-of-tubesheet transitions, dent indications, etc. No degradation of this type was observed on any of the tubes tested.

NRC Question No. 7

It was reported on Page 10 of the annual report that a 0.720-inch bobbin probe would not pass through one of the Row 2 U-bends. Was this bobbin probe restriction service induced? In past inspections, was this Row 2 U-bend inspected with a larger probe?

Dominion Response

In recent inspections it has not been unusual to find a few tubes in this area of the bundle that have difficulty passing the largest qualified bobbin probe, i.e. the 0.720 probe in the tight row U-bends. Past outage inspections have verified that these types of "restrictions" are typically artifacts of original manufacture. In outages several cycles ago, probe downsizing to as small as 0.680 was an accepted practice; consequently, these tubes were not flagged to receive additional testing. Recent qualification requirements permit only downsizing to 0.700 probes, and the subject tube was able to pass this size probe. Had it not been able to pass the smaller probe, a rotating coil inspection with the 0.680 rotating probe, which is a qualified inspection, would have been required. Although an acceptable bobbin inspection was performed, the tube was also included in the rotating coil special interest exams to obtain additional information for future inspection comparisons. Historical data on this tube back to 1991 shows the presence of this condition and is similar to the artifacts in this area of the bundle identified in the past.

NRC Question No. 8

Anomaly codes reported in 2000 and inspected in 2005 were presented in Table 5 on Page 10 of the annual report. Please provide more information regarding the nature and cause of these anomalies and the basis for the inspections performed.

Dominion Response

As noted in previous annual reports, these anomaly signals are typically original manufacturing related conditions that are identified during the course of the top-of-tubesheet rotating coil exam. They are typically from burnish marks, tube dings induced during handling, and edge effects as the tube was expanded into the tubesheet. These signals are benchmarked to the type of signals that were the subject of two tubes extracted for laboratory examination on Surry Unit 1 during the 1990 outage. In addition, in 1997 an ultrasonic testing (UT) program on Unit 2 included these signals in a validation effort that supported original tube pull assumptions for this type of signal and benchmarked "Plus Point" probe responses on this type of signal. No corrosion degradation was noted.

Since subsequent inspections have identified no corrosion degradation mechanisms at the hot leg top-of-tubesheet, a sample rotating coil inspection program continues to be employed. Although no definitive analysis points to the conclusion that the anomaly conditions induce additional stresses at an already geometry-related stress condition (i.e. tube expansion at the tubesheet), a sample of these anomalies are included in ongoing inspections with the regular inspection sample. They have been included in sample programs since the 1998 timeframe with no abnormal conditions noted.

NRC Question No. 9

On Page 11 of the annual report, it was indicated that data using sizing method ETSS 96910.1 was used in the condition monitoring assessment since it provided more realistic depth estimates. Please provide the basis for stating this sizing method is more realistic than the sizing method in ETSS 21998.1.

Dominion Response

In general, two sizing techniques were used to determine the dimensions of the flaws. ETSS 21998.1, and its associated flat-bottom hole calibration standard, is appropriate for sizing volumetric indications which are less than 0.25" in length. This technique produces increasingly conservative depth estimates as the flaw length increases. For flaws greater than 0.25" long, the depth estimates are overly conservative. Plugging decisions were made on the basis of the more conservative ETSS 21998.1 depth estimate for the referenced wear related indications. As noted in Table 7, some foreign object wear indications necessitated the use of the ETSS 96910.1 technique due to size or configuration. The largest indication condition monitoring assessment using the EPRI Flaw Handbook profiling method bounds all indications as noted in Figure 1 of the annual report.

NRC Question No. 10

In Table 7, tube R31C28 was reported to have a wear indication with a measured wall penetration of 98 percent and Tube R32C28 was reported to have a wear indication with a measured wall penetration of 90 percent using the ETSS 21998.1 sizing method. The NRC staff is aware that the wear indications were attributed to a loose part which could not be removed and that the tubes were plugged and stabilized. Please discuss how the magnitude of these indications changed from past outages. In addition, were these tubes in-situ pressure tested? If so, discuss the results.

Dominion Response

Definitive growth data cannot be obtained since no record of rotating coil data was found in previous inspections for these locations. No sizing of indications at the previous outage was performed since the data was recorded as "NDD" (No Detectable Degradation) for this area. Applying enhanced techniques of a three-channel frequency mix, i.e. "turbo mix", the bobbin probe provided evidence of a volumetric signal and was ultimately determined to be a foreign object wear indication. Applying these same set-ups to prior historical raw data, some evidence of a volumetric signal could be obtained indicating prior existence of a possible foreign object as indicated in Table 7 of the annual report. Applying the ETSS 96910.1 technique to the historical raw data, a 56% through wall (TW) depth was determined assuming signal presence back to 1996. This result implies a relatively slow growth rate. These tubes were not in-situ pressure tested.

NRC Question No. 11

In Table 3 on Page 7 and 8 of the annual report, several indications are reported in 2000 but not in 2005 or vice versa. Please discuss why an indication that was reported in 2000 was not reported in 2005 or vice versa. In addition, Tube R37C30 was reported *to have a through-wall depth of 41 percent and Tube R38C34 was reported to have a through-wall depth of 43 percent in 2000. Since a through-wall depth was not provided for these tubes for 2005, confirm that these tubes were plugged in 2000. If they were plugged, why were they included in this table?*

Dominion Response

It is not unusual to have indications that were near the typical reporting threshold of 10% TW appear at one outage and not be reported at the next outage simply due to instrument variations from outage to outage. Tubes R37C30 and R38C34 were plugged in 2000 since their measured depths were greater than the 40% TW plugging limit. Two additional tubes, R28C49 and R35C54, were preventively plugged based on conservative growth projections.

The TW extents, even for plugged tubes, are included in the table, since all growth data remains in the data set that is used to calculate the statistical growth numbers for the operational assessment projection.

NRC Question No. 12

Please discuss whether there is any other industry data to support the tube support plate wear assumptions made in Section 3.2 of the annual report. If there is no other data, discuss why the degradation was not assumed to initiate over the last cycle rather than the last three cycles.

Dominion Response

There have been few incidences of this type of indication at the Surry units. Historical data from the Surry units provide the best comparison, since both Surry 1 and 2 had been in service for over 19 EFPY at their most recent inspection and are the longest in-service units in the industry since replacement. Industry data would provide little additional benefit in such a comparison. Based on unit history a three-cycle growth assumption is viewed as very conservative.

NRC Question No. 13

The annual report dated February 23, 2004 (Agencywide Documents Access and Management System No. ML040630162), for the Surry 1/2 refueling outages in 2003, stated that a denting pattern on the peripheral tubes at the 6th and 7th tube support plates was found on both units. Inspections confirmed that these dents tend to be located near tube support wedge locations in upper elevations of periphery tubes. In addition, it was reported that these dent signals will continue to be monitored. For Surry 1/2, please discuss the results of any dent inspections performed during the 2005 refueling outages (e.g., were the results consistent with past inspection results, are the dent signals changing with time).

Dominion Response

Dominion employs very conservative reporting criteria for dent related signals, i.e., 2 volts and greater. Screening for additional testing for dent signals has been discussed in previous annual reports. This is the second inspection on this generator (2 "C") on the same reporting basis. The previous inspection was conducted in the fall of 2000. A historical review was performed on called dent signals that included the referenced upper support plate signals over the entire generator. Using the area with the highest number of reported signals at the 7th cold leg support, the 2005 data indicates no statistically significant increase in voltage amplitude from the 2000 inspection. Approximately 92% of these dent signals reported at both outages showed a range of change from (-)0.6 volt to (+)0.6 volt. None were flagged at the 2005 inspection from the historical review process as requiring a rotating coil inspection due to amplitude change.