VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

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United States Nuclear Regulatory Commission
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VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION UNIT 2
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
2008 STEAM GENERATOR INSERVICE INSPECTION REPORT

By letter dated November 14, 2008, Virginia Electric and Power Company (Dominion) submitted information summarizing the results of steam generator (SG) tube inspections performed at Surry Power Station Unit 2 during the Spring 2008 refueling outage. On June 15, 2009, the NRC requested additional information related to the SG inspections. The NRC's questions and Dominion's responses are provided in the attachment to this letter.

If you have any questions or require additional information, please contact Mr. Jerry Ashley at (757) 365-2161.

Very truly yours,

G. T. Bischof
Site Vice President

Attachment

Commitments made in this letter: None

A047
NRR

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ATTACHMENT

Response to NRC Request for Additional Information Regarding 2008 Steam Generator Inservice Inspection Report

Surry Power Station Unit 2

Virginia Electric and Power Company
(Dominion)

By letter dated November 14, 2008 (Serial No. 08-0687), Virginia Electric and Power Company (Dominion) submitted information summarizing the results of the Spring 2008 steam generator (SG) tube inspections performed at Surry Power Station Unit 2. On June 15, 2009, the NRC requested additional information related to the SG inspections. The NRC questions and Dominion's response are provided below.

NRC Question 1

For each refueling outage and steam generator (SG) tube inspection, including mid-cycle inspections, since the spring 2002 outage, please provide the effective full power months of operation that the SGs accumulated.

Dominion Response

The effective full power months (EFPM) of operation that the SGs accumulated for the respective outages are:

End of Cycle (EOC)	Outage	Accumulated SG EFPM
17	Spring 2002	198.2
18	Fall 2003	214.8
19	Spring 2005	231.2
20	Fall 2006	247.9
21	Spring 2008	264.6

NRC Question 2

The scope section of the November 14, 2008, letter indicates that all tubes which were either not expanded or only partially expanded into the tubesheet would be examined with a +Point™ probe, in SGs B and C. Please discuss how many tubes fall into each category, the extent of any partial expansions, and the results of the inspections.

Dominion Response

The number of tubes from each SG in their respective categories is:

Condition	SG B	SG C
No Expansion – Hot Leg	4	3
No Expansion – Cold Leg	0	4
Partial Expansion – Hot Leg	0	0
Partial Expansion – Cold Leg	0	0

The full tubesheet depth of each affected location was examined with the rotating probe. No indications of associated degradation were identified. There were no partial expansions.

NRC Question 3

You provided responses to an NRC staff request for additional information in a letter dated August 10, 2007 (ADAMS Accession No. ML072280196), regarding inspections performed in your 2006 refueling outages for SPS Unit 1. Responses 7 and 11 indicated that inspection of the bottom 2 inches of SG hot-leg tubes was not necessary because, based on SPS on Unit 2 lower operating hot-leg temperature, the expected time to develop cracking had not been reached and would not be reached before the 2008 refueling outage. In the fall of 2007, cracking in this region was found in hot-leg and cold-leg SG tubes at Catawba Nuclear Station, Unit 2 (NRC Information Notice 2008-07, ADAMS Accession No. ML080040353). Given the challenge in accurately predicting the onset of cracking and the finding of cold-leg cracking at Catawba, please provide a technical basis for not performing any inspections in the cold-leg tube ends during your 2008 refueling outage.

Dominion Response

During the 2007 inspection of Catawba Unit 2 steam generators, indications interpreted as cracks had been observed in a number of cold leg tube ends. These indications were initially reported as being located within the weld material. An industry peer review of this inspection data performed in early 2008 concluded that the indications were in fact located within the tube material and not in the weld. The indications were assumed to have been caused by cracking; however, no tube sections have been removed and examined in the laboratory to confirm this assumption.

The corrosion cracking potential for Alloy 600TT depends, in part, on its stress state and on the chemistry and temperature of the environment. Since the manufacturing processes are the same for both the hot leg and cold leg, there is no differentiation between hot leg and cold leg at the stage of tube bundle manufacturing. Therefore, it can be concluded that the stress distribution of the material on the cold leg is the same as that of the hot leg. The chemistry of the primary water environment is also the same on the cold leg and the hot leg, leaving temperature as the only significant variable differentiating SCC behavior between the hot leg and cold leg. Since the cold leg is at a substantially lower temperature than the hot leg, the potential for cracking is significantly lower on the cold leg than on the hot leg. For that reason, inspection of the cold leg tube ends was not considered to be necessary during the Surry Unit 2 Spring 2008 outage.

During the recently completed Surry Unit 1 Spring 2009 EOC22 refueling outage, 20% of the cold leg tube ends in SGs A and C, and 100% of the cold leg tube ends in SG B were examined with rotating probes. No indications of cold leg cracking were identified. Since both Surry units have the same design steam generators, which were fabricated in the same facility in the same era, and have essentially the same operating history, the Unit 1 inspection experience is more relevant to the expected Surry Unit 2 performance than the Catawba findings. This experience supports our prior conclusions with respect to the susceptibility of the Surry units to cold leg tube end cracking.

(It should be noted that during the Surry Unit 2 Spring 2008 EOC21 refueling outage, full tubesheet depth, rotating probe examinations were performed in a small number of cold leg tubes. 12 tubes in SG B and 22 tubes in SG C were examined and the results indicated no degradation.)

NRC Question 4

The scope section of the November 14, 2008, letter states that during the 100 percent bobbin program "all tubes" were evaluated for the U-bend offset signal and that no offset signals were noted. However, on page 10 of the same letter, it was indicated that no precursor signals (e.g., Distorted Support Signals) were found in tubes identified as potentially having an elevated residual stress condition. Since the eddy current offset is normally attributed to an elevated residual stress condition in the tube, please clarify the number of tubes with the elevated residual stress condition. Please include in the response how many of these tubes are in low rows (i.e., stress relieved) and high rows.

Dominion Response

During the Surry Unit 2 Spring 2008 EOC21 refueling outage, bobbin probe inspection of SG B and SG C, the U-bend region of low row tubes (i.e., those with stress relieved U-bends), was evaluated for the offset signal characteristic of elevated residual stress. No elevated residual stress was identified.

While this review is useful for the low row tubes, it provides no information with respect to the potential for elevated residual stress in high row tubes (i.e., those whose U-bends were not stress relieved). The high row tubes were evaluated for relative residual stress in 2004 using a statistical method identified by the industry's Steam Generator Management Program. This evaluation identified two tubes in SG B and 14 tubes in SG C as having potentially elevated residual stress.

NRC Question 5

Page 3 of the November 14, 2008, letter indicates that the secondary side inspections did not identify any component degradation that would compromise tube integrity. Please discuss degraded conditions found on the secondary side of the SGs, such as erosion of the J-tubes, and the deposit loading at the support plates.

Dominion Response

During the Surry Unit 2 Spring 2008 EOC21 refueling outage, the SG B 7th Tube Support Plates and Anti Vibration Bars (AVBs) were visually inspected. Although there was evidence of a uniform layer of scale, this inspection identified no evidence of degradation. Inspection of the periphery of the bundle showed minimal evidence of powdery sludge and no evidence of loose scale on the plate or in the broached tube support plate holes. No degradation of these components was observed that would compromise tube integrity. J-tube inspections found minimal flow accelerated corrosion. A comparison was performed from the previous inspection with limited degradation. An evaluation was performed and noted in the condition monitoring and operational assessment. J-tubes are a part of the Surry Power Station long term inspection plans and are inspected every third outage cycle for each steam generator.

NRC Question 6

Regarding the fourth bullet on page 10 of the November 14, 2008, letter:

a. *The statement is made that no foreign objects were found among the tubes with volumetric indications and their neighboring tubes. However, both the text and Table 6 on page 8 indicated that three tubes in SG C were plugged and stabilized due to foreign object wear and the inability to remove the object causing the wear. In addition, page 3 indicated that seven foreign objects (possible loose parts (PLPs)) were confirmed by eddy current in SGs B and C. Please clarify the following:*

   i. *How the seven foreign objects noted on page 3 were initially detected and then verified, since possible loose parts are usually identified from the eddy current data and then confirmed visually.*

Dominion Response

The seven objects were initially identified with eddy current and confirmed by visually examining the location on the secondary side.

   ii. *Whether PLPs from the eddy current data were inspected visually to determine if a part was present. If the region associated with a PLP was not inspected, please discuss how these tubes were dispositioned.*

Dominion Response

All reported PLP indications were examined visually for loose parts with the exception of the three tubes with degradation at the baffle plate. The three tubes in SG C containing wear and PLP indications at the baffle plate on the hot side could not be examined visually. Consequently, these tubes were stabilized and plugged.

   iii. *Whether all detected loose parts/foreign objects were removed from the SG, and if not removed, whether an analysis was performed confirming tube integrity would be maintained until the next inspection.*

Dominion Response

A total of 17 foreign objects including sludge rocks and scale were detected in SGs B and C (none in SG A). Sludge rocks and scale pose no threat to tube integrity and in general were not removed. All other identified foreign objects were removed from SG C. Two (2) identified metal objects in SG B, a metal remnant and a short piece of wire, were not retrieved. Both objects were fixed in place and are not expected to cause tube wear. The metal remnant is wedged between the tubelane blocking device and tubes R1C12 and R1C23. Review of the prior eddy current data showed the object to be present since 2005 with no evidence of wear. The wire is embedded in the sludge pile and is unlikely to interact with any tubes. These parts were evaluated as part of the Operational Assessment document confirming that tube integrity would be met for the upcoming cycle.

b. *A 32 percent through-wall volumetric indication is listed as the largest indication, yet this indication does not appear in Table 4 or 5 on page 7. Please clarify.*

Dominion Response

The reference to 32% through wall maximum was a typographical error. The maximum non-AVB wear volumetric indication depth reported during Surry Unit 2 Spring 2008 EOC21 refueling outage was 30% through wall.

NRC Question 7

Tables 2 and 3 of the November 14, 2008, letter contain depth measurements in a column labeled 2003; however, Note A of Tables 2 and 3 states, "Not reported in 2005 - used 10% as default depth." Please clarify the years referenced in the column headers and in the "Note 'A's." In addition, please clarify why year 2000 datum was reported for the tube in row 44 column 61.

Dominion Response

Table 2, Note A should read "Not reported in 2003 - used 10% as default depth". The Table 3, column heading should be "2005" instead of "2003".

The AVB wear flaw at SG C R44 C61 AV1 was reported as 10% through wall in 2000, was not reportable in 2005 (i.e., was sized at <10% through wall), and was again reported as 10% through wall in 2008. In order to establish a growth rate, the previously reported depth (i.e., 10% through wall in 2000) was used.

NRC Question 8

Page 14 of the November 14, 2008, letter indicates that, "The accident condition leak rate from cracks in the tubesheet is limited to the operating leakage times 2.5 or less." Please confirm that the intent of this sentence is the same as, "The accident condition leak rate from cracks in the tubesheet is limited to 2.5 times the operating leak rate from cracks in the tubesheet."

Dominion Response

The intent of the sentence in the November 14, 2008 letter is that the accident condition leak rate from cracks in the tubesheet is limited to 2.5 times the operating leak rate from cracks in the tubesheet.