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July 5, 2011

Mr. David A. Heacock
President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: SURRY POWER STATION, UNIT NO. 2 – SUMMARY OF CONFERENCE CALL REGARDING THE SPRING 2011 STEAM GENERATOR TUBE INSPECTIONS (TAC NO. ME6146)

Dear Mr. Heacock:

Following the Indian Point 2 steam generator (SG) tube rupture in 2000, the Nuclear Regulatory Commission (NRC) implemented changes to improve the oversight of licensees' SG programs. Two such changes involved formalizing the processes for conducting conference calls with licensees during the outage and for reviewing inspection reports, which are submitted in accordance with Technical Specification reporting requirements.

On May 12, 2011, the NRC staff participated in a conference call with Virginia Electric and Power Company (the licensee) representatives regarding the ongoing SG tube inspection activities at Surry Power Station Unit No. 2. Enclosed are the conference call summary and the information provided by the licensee to support the call.

Sincerely,

Karen Cotton

Karen Cotton, Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-281

Enclosures:
1. Conference Call Summary
2. Surry Meeting Notes

cc w/encls: Distribution via Listserv

SUMMARY OF CONFERENCE CALL WITH SURRY POWER STATION, UNIT NO. 2

REGARDING THE SPRING 2011 STEAM GENERATOR

TUBE INSPECTION RESULTS

On May 12, 2011, the staff of the Steam Generator Tube Integrity and Chemical Engineering Branch of the Division of Component Integrity participated in a conference call with Virginia Electric and Power Company (the licensee) representatives regarding the ongoing steam generator (SG) tube inspection activities at Surry Power Station, Unit No. 2 (Surry Unit 2). Information provided by the licensee for the conference call is included as an attachment to this enclosure.

Surry Unit 2 has three Westinghouse model 51F SGs. Each SG has 3,342 thermally treated Alloy 600 tubes with an outside diameter of 0.875 inches and a nominal wall thickness of 0.050 inches. The tubes are hydraulically expanded for the full depth of the tubesheet at each end. The tubes are supported by stainless steel support plates with quatrefoil-shaped holes. The U-bend region of the tubes installed in Rows 1 through 8 was thermally treated after bending in order to reduce stress.

At the time of the May 12, 2011, conference call, tube inspections were still in progress. Additional clarifying information or information not included in the document (Agencywide Documents Access and Management System, Accession No. ML11124A009), provided by the licensee is summarized below:

- The licensee stated that all loose parts that could be located through secondary side inspections were removed from the SGs
- During the secondary side inspections of the upper internals, a hole was discovered in a riser barrel. As a result, the licensee examined all riser barrels in both SGs. The licensee repaired several riser barrels with ¾" inconel plates

The staff did not identify any issues that required follow-up action at this time, however, the staff asked to be notified in the event that any unusual conditions were detected during the remainder of the outage.

Surry Meeting Notes for NRC Call Thursday May 12, 2011 at 1:00PM

1. The Nuclear Regulatory Commission (NRC) staff requests clarification on the definition of over-expansion that was provided in your response dated April 25, 2011 (Agencywide Documents Access and Management System, Accession No. ML11124A009) to a request for additional information regarding the End of Cycle 22 Steam Generator Tube Inspection.

   - OXP: Local area within tubesheet where diameter is larger than nominal
   - OVR: Local area above the tubesheet where diameter is larger than nominal

2. Discuss any trends in the amount of primary-to-secondary leakage observed during the recently completed cycle.

   - No reportable leakage and no increasing leakage trend.

3. Discuss whether any secondary side pressure tests were performed during the outage and the associated results.

   - No secondary side pressure tests were performed

4. Discuss any exceptions taken to the industry guidelines.

   - No exceptions were taken to industry guidelines

5. For each SG, provide a description of the inspections performed including the areas examined and the probes used (e.g., dents/dings, sleeves, expansion-transition, U-bends with a rotating probe), the scope of the inspection (e.g., 100% of dents/dings greater than 5 volts and a 20% sample between 2 and 5 volts), and the expansion criteria.

   - ECT inspections will be performed in two SGs (B & C)

   - Includes:

     - Full length bobbin exam of all tubes (excluding row 1 and 2 ubends)
     - +Point inspection of 58% of hot leg expansion transitions
     - +Point inspection of 50% of hot leg OXPs and a small sample of the highest voltage cold leg OXPs
     - +Point inspection of all row 1 and 2 ubends
     - +Point inspection of 50% of 5 tube deep periphery on cold leg TTS
     - +Point inspection of 50% of hot leg dents ≥2 Volts and a small sample of
     - the highest voltage cold leg dents
     - +Point inspection of special interest locations (e.g., PLPs, I-codes, etc)

   - SG C ECT is complete; SG B is underway

- Expansion criteria:
    - The only findings that have required expansion were PLP calls that were confirmed by +Point.
    - The expansion involves bounding the region with +point exams until a "clean" one-tube-deep ring is achieved.
    - No cracking was identified. No other degradation was identified that exceeded the plugging criteria or triggered scope expansion.

6. For each area examined (e.g., tube supports, dent/dings, sleeves, etc), provide a summary of the number of indications identified to-date for each degradation mode (e.g., number of circumferential primary water stress corrosion cracking indications at the expansion transition). For the most significant indications in each area, provide an estimate of the severity of the indication (e.g., provide the voltage, depth, and length of the indication). In particular, address whether tube integrity (structural and accident-induced leakage integrity) was maintained during the previous operating cycle. In addition, discuss whether any location exhibited a degradation mode that had not previously been observed at this location at this unit (e.g., observed circumferential primary water stress corrosion cracking at the expansion transition for the first time at this unit).

- Cracking:
    - No indications of cracking have been identified

- AVB Wear (tubes / indications):

SG B	SG C
9 / 10	36 / 54

(SGC has historically had more AVB wear than B)

- Max depth identified: SG B 17 %TW; SG C 33 %TW
- Essentially dormant
    - Avg growth rate ~0 %TW/cycle
    - 95/50 growth rate is ~2%TW/cycle (reflects NDE sizing uncertainty)
- Structural and leakage performance criteria were met during previous cycle

- Foreign object wear:

SG B:

- 3 FO wear flaws identified during previous outages were resized
- None of them changed
- No new FO wear identified
- Structural and leakage performance criteria were met during previous cycle

SG C:

- o 21 FO wear flaws identified during previous outages were resized
- o None of them changed
- o Identified 4 new FO wear flaws at hot leg baffle plate (BPH)
- o Max depth 25 %TW
- o Data review shows small bobbin response with no change from 2008
- o Identified 3 new FO wear flaws at hot leg TTS (adjacent to each other)
- o Max depth 27 % TW
- o Data review shows small bobbin response with no change from 2008
- o Structural and leakage performance criteria were met during previous cycle

- <u>Tube Support Wear</u>:

  SG B:

  - o None

  SG C:

  - o 2 tubes have TSP wear
  - o Each tube has one affected elevation:
    - R37 C73 TSP7 Cold Leg
    - Previously reported in 2005, although there is now a shallow reportable flaw at a second land contact (9 %TW)
    - Max depth 20 %TW, no change since 2005
    - R3 C72 TSP3 Cold Leg
    - Newly reported, however no bobbin signal change since 2005
    - Max depth 9 % TW
  - o Structural and leakage performance criteria were met during previous cycle

- <u>New degradation modes</u>:

  - o None

7. Describe repair/plugging plans

   - Thus far no tubes requiring plugging have been identified in either SG. Inspections are still underway.

8. Describe in-situ pressure test and tube pull plans and results (as applicable and if available).

   - There are no plans for a tube pull or in-situ testing.

9. Discuss the following regarding loose parts:

    - What inspections are performed to detect loose parts
    - A description of any loose parts detected and their location within the SG (including the source or nature of the loose part, if known)
    - If the loose parts were removed from the SG
    - Indications of tube damage associated with the loose parts

    - <u>Inspections:</u>

        - o 100% bobbin probe exam SG B and C
        - o +Point exams in hot leg and cold periphery
        - o Secondary side visual inspections of regions identified during ECT

10. Discuss the scope and results of any secondary side inspection and maintenance activities (e.g., in-bundle visual inspections, feedring inspections, sludge lancing, assessing deposit loading, etc).

    - The feedrings in all 3 SGs were replaced during this outage
    - No sludge lancing was performed
    - Secondary side inspections in SGs B & C to investigate regions of interest identified during the ECT exam
    - Results:

11. Discuss any unexpected or unusual results.

    - New Dent:

        - o A new dent was identified on a periphery tube in SG C
        - o Location corresponds to 90 degree hand hole
        - o Caused by maintenance activity during 2008 or 2009 outage
        - o Dent is relatively small (9.6 Volts) and did not restrict passage of 0.720-inch bobbin probe
        - o Examined with +Point - no tube degradation

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ADAMS Accession No. ML11173A154 *Summary transmitted by memo dated 5/31/11

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DATE	6/30/11	6/29/11	05/31/11	6/30/11	7/5/11

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