FENOC

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February 20, 2009

L-09-028

ATTN: Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT:
Beaver Valley Power Station, Unit No. 2
Docket No. 50-412, License No. NPF-73
Response to Request for Additional Information Re: The 2008 Steam Generator Tube Inspection Report (TAC Nos. MD9559 and ME0097)

By letter dated August 7, 2008, as supplemented by a letter dated October 28, 2008, FirstEnergy Nuclear Operating Company (FENOC) submitted information summarizing the results of the 2008 steam generator tube inspections at Beaver Valley Power Station Unit No. 2 (BVPS-2). By letter dated January 21, 2009, the NRC staff requested additional information in order to complete its review of the information concerning the 2008 steam generator tube inspections at BVPS-2. The FENOC response to this request is attached.

There are no regulatory commitments contained in this letter. If there are any questions or if additional information is required, please contact Mr. Thomas A. Lentz, Manager – Fleet Licensing, at 330-761-6071.

Sincerely,

Peter P. Sena III

Attachment:
Response to Request for Additional Information, 2008 Steam Generator Tube Inspections, Beaver Valley Power Station, Unit No. 2

cc: NRC Region I Administrator
NRC Resident Inspector
NRR Project Manager
Director BRP/DEP
Site BRP/DEP Representative

A001
NRR

On April 25, 2008, two phone calls were held with the NRC to discuss the expansion plan that resulted from the detection of a circumferential flaw located at a freespan ding in SG C. By letter dated May 27, 2008 (ADAMS Accession No. ML081410092), the Nuclear Regulatory Commission (NRC) staff summarized information previously provided to the NRC staff concerning the 2008 SG tube inspections at BVPS-2. By letter dated August 7, 2008 (Agencywide Document Access and Management System (ADAMS) Accession No. ML082240290), as supplemented by letter dated October 28, 2008 (ADAMS Accession No. ML083050508), FirstEnergy Nuclear Operating Company submitted information summarizing the results of the 2008 steam generator (SG) tube inspections for Beaver Valley Power Station, Unit No. 2 (BVPS-2).

To complete their review, the NRC staff has requested the following additional information in a letter dated January 21, 2009. The staff request is provided below in bold type followed by the FENOC response for BVPS-2.

1. **As a result of finding a circumferential flaw in a 2.6 volt ding, additional inspections of dings were performed. The scope in SG C (the SG where the flaw was detected) appeared biased toward the upper elevations in the tube bundle. The upper elevation on the hot-leg is generally cooler than the lower elevations. Given the general trend that stress-corrosion cracking is more predominant at higher temperature regions in the tube bundle (i.e., lower elevations of the hot-leg), discuss the basis for biasing the inspections of the dings to the upper region of the tube bundle.**

   The freespan ding indication reported during the spring 2008 maintenance and refueling outage (2R13) had a small circumferential length response. A second ding, located several inches away on the opposite side of the tube, had a similar circumferential length response. The circumferential involvement of the ding was measured at approximately 90 degrees while the circumferential extent of the indication was measured at approximately 40 degrees. While these two dings do not fit the formal definition of a "ding pair" based on the axial separation, the characteristics of each ding suggest that they are related to the original tube installation. The elevation of ding pairs is strongly biased to the upper span regions of the tube bundle. The expansion scope was intended to concentrate on inspection of elevations surrounding the 2R13 indication, which occurred in the upper region.

   The elevation of the 2R13 indication in SG C was at the 6th hot leg tube support plate +30.97 inches or several inches below the 7th hot leg tube support plate.

The expansion scope included the following regions of SG C: (a) 100 percent of the dings (≤ 5.0 volts) from the 5th hot leg tube support plate up to 4.0 inches above the 8th hot leg tube support plate, (b) 100 percent of the dings (≤ 5.0 volts) from the 5th cold leg tube support plate up to 4.0 inches above the 8th cold leg tube support plate (c) 25 percent of the dings (≤ 5.0 volts) from the secondary face of the hot leg tubesheet up to the 5th hot leg tube support plate and (d) 25 percent of the dings (≤ 5.0 volts) from the secondary face of the cold leg tubesheet up to the 5th cold leg tube support plate.

Therefore, the expansion scope not only included (a) 100 percent of dings (≤ 5.0 volts) between the 6th hot and cold leg tube support plates up to the 7th hot and cold leg tube support plates but also included (b) 100 percent of dings (≤ 5.0 volts) at the next lower span (5th hot and cold leg tube support plates up to 6th hot and cold leg tube support plates) and (c) at the next higher span (7th hot and cold leg tube support plates up to 8th hot and cold leg tube support plates plus 4.0 inches). Thus the indication was bounded in elevation in both directions. The expansion scope addressed the area of the tube most likely to develop stress corrosion cracking. In addition, circumferential outside diameter stress corrosion cracking in dings does not represent a structural or leakage concern as the length of the flaw will be limited to the developed stress field, which is a result of the ding geometry.

On the hot leg side of SG C (from the top of tubesheet to the 8th tube support plate plus 4.0 inches), a total of 249 ding locations were reported. Of these 249 ding locations, 235 were ≤ 5.0 volts. One hundred eleven (111) of these are located between the 5th hot leg tube support plate up to 4.0 inches above 8th hot leg tube support plate. A 25 percent sample of the remaining 124 ding locations below the 5th hot leg tube support plate was performed. Other than the ding indication that was originally reported, no additional indications were observed from any of the hot leg ding locations that were examined.

On the cold leg side of SG C (from the top of tubesheet to the 8th tube support plate plus 4.0 inches), a total of 237 ding locations were reported. Of these 237 ding locations, 229 were ≤ 5.0 volts. Eighty-six (86) of these are located between the 5th cold leg tube support plate up to 4.0 inches above the 8th cold leg tube support plate. A 25 percent sample of the remaining 143 ding locations below the 5th cold leg tube support plate was performed. No indications were observed from any of the cold leg ding locations that were examined.

As part of the base steam generator inspection scope, a 25 percent sample of "ding pairs" was performed. By definition, a "ding pair" is two freespan dings located approximately 180 degrees apart circumferentially and spaced within 0.75 inches (+/-0.38 inches) axially of each other. During the fall 2006 maintenance and refueling outage (2R12), 100 percent of "ding pairs" were inspected with no indications being reported. In addition, all > 5.0 volt freespan dings have been inspected for several consecutive outages. No indications were observed from any of the ding locations that were examined.

2. **Provide the bobbin voltage amplitudes for the three indications of axially oriented outside diameter stress-corrosion cracking indications detected at the tube support plate elevations.**

   Three tubes (R11 C15, R20 C12, R32 C68) in SG C were reported with axial hot leg tube support plate indications. The bobbin amplitudes were 0.77 volts, 0.78 volts, and 0.31 volts, respectively.

3. **Several possible loose part indications were detected in SGs B and C. Discuss whether these loose parts were confirmed to be present through visual inspections. If so, discuss whether the loose parts were removed or how they were dispositioned.**

   In SG B, a small piece of weld slag was observed but not retrieved. The weld slag has been present for three cycles and possibly longer. An engineering evaluation determined that it is acceptable to leave the slag in the steam generator for the current operating cycle because it is fixed in place and has not caused any reportable tube wall wear. No loose parts or foreign objects were visually observed at the locations identified through the eddy current examinations in SG C.

4. **Discuss the results of the upper steam drum inspection of SG A (i.e., the inspections of the moisture separation equipment and feedwater header and selected J nozzles).**

   Inspection of the SG A moisture separation equipment (e. g., swirl vanes and riser barrel outlets) did not indicate any evidence of erosion/corrosion.

   The Unit 2 J-nozzles were replaced prior to plant operation with Alloy 600 J-nozzles. Normal minor erosion/corrosion at the feedwater header to J-nozzle interface was noted.

   A small through-wall penetration of the SG A feedwater header was noted near the J-nozzle 33 location. Manufacturing records indicate that the original J-nozzle location interfered with the placement of a seismic restraint. The J-nozzle was removed and relocated to the opposite side of the seismic restraint, and the original hole location was plugged with a solid carbon steel bar welded in place at the factory. This plug extended down into the feedwater header flow stream by approximately 1/2 inch. It is believed that the turbulence created by the plug resulted in erosion of the feedwater header reducer to plug weld. The location of the hole is at the leading edge of the plug. This area would be expected to have the highest velocities within the feedwater header. The location is actually on the eccentric reducer, which reduces from the 16-inch inlet tee diameter down to the 10-inch feedwater header diameter. The flow velocity would be accelerated in this area due to the area reduction resultant from the eccentric reducer shape. This condition was repaired by welding a carbon steel plate on the outer surface of the affected area. The location of the repair weld was such that the original feedwater header plug was subsequently attached to the carbon steel plate by welding. Visual inspection of the inside surface of the reducer was also performed. This inspection confirmed that the back side of the plug/reducer was not experiencing any type of erosion/corrosion.

5. **A high frequency plus-point examination was performed in the U-bend region of any row 1 tubes that had excessive noise values. Discuss whether the same practice was employed for the row 2 tubes. If not, provide the basis for this decision.**

The inspection scope included a provision for high frequency plus point examination of the U-bend region of any row 1 tubes that had excessive noise values. However, high frequency examination was not necessary because excessive noise values were not encountered. The row 2 U-bend noise levels were not screened during 2R13.

The high frequency plus point examination is only applied if the mid-range plus point probe noise level is greater than 0.65 volts (measured using vertical maximum). The 0.65 volts is conservatively based on noise level evaluations of the row 1 U-bend region. Assessment of the row 2 U-bend noise levels shows the noise condition to be significantly less than the noise levels for the row 1 U-bends. During 2R13, no row 1 U-bend noise levels exceeded the 0.65 volts threshold. Therefore, based on past assessments, no row 2 U-bend noise levels would have been expected to exceed the 0.65 volt limit. The high frequency inspection (if required) is performed as a defense-in-depth inspection as SG secondary side deposits do not contain high levels of copper as was found at other plants. Thus, the mid-range plus point is considered an appropriate inspection device. Small radius U-bend primary water stress corrosion cracking (PWSCC) is not expected due to the application of U-bend heat treatment prior to plant operation. This process was applied at other units (with SGs that were subsequently replaced) which operated at significantly higher temperatures than BVPS-2. Small radius U-bend PWSCC was not reported at these other units.

6. **Discuss the results of the plus-point inspections performed at the bulges and over expansions below the F* distance.**

One hundred percent of the bulges and over expansions, located above the hot leg tubesheet neutral axis but below the F* distance, were examined using a plus point probe. This inspection is not required due to application of the F* criteria but was conservatively performed to determine if such degradation existed below the F* distance. No degradation below the F* distance was reported. During 2R12, a 100 percent plus point inspection of both hot and cold leg bulges and over expansions above the tubesheet neutral axis was performed. No degradation was reported. Such degradation is not expected for Unit 2 due to shot peening of both the hot and cold tubesheet regions prior to operation.

7. **A visual inspection was performed on all tube plugs. Discuss the results of these inspections and discuss whether this inspection included verifying that all plugs were present.**

As part of the normal SG inspection process, a visual examination is performed each time the primary side is accessed to document the condition of the hot and cold leg channelheads. This process includes tube plug accountability. During 2R13, as well as all prior outages, the examinations verified that the correct number of tube plugs were present and in the proper tube location. No anomalies were reported.