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

Subject: Beaver Valley Power Station, Unit No. 1 and No. 2
BV-1 Docket No. 50-334, License No. DPR-66
BV-2 Docket No. 50-412, License No. NPF-73
Supplemental Information in Support of 2001-2002 Steam Generator Tube Outages Inspection Reports

This letter provides the FirstEnergy Nuclear Operating Company (FENOC) response to the NRC request for additional information (RAI) dated June 4, 2003, pertaining to various previously submitted reports summarizing the steam generator tube inspections performed during refueling outages 1R14 and 2R09 on Beaver Valley Power Station (BVPS) Units 1 and 2, respectively.

The response to the requested information in Enclosure 1 from the NRC letter dated June 4, 2003, for BVPS Unit 2 regarding the End of Cycle 9 Steam Generator Inspection Report is provided in Attachment A of this letter.

The response to the requested information in Enclosure 2 from the NRC letter dated June 4, 2003, for BVPS Unit 1 regarding the additional questions provided in support of the 1R15 outage conference call is provided in Attachment B of this letter.

The response to the requested information in Enclosure 3 from the NRC letter dated June 4, 2003, for BVPS Unit 1 regarding follow-up questions from the 1R15 steam generator outage conference call will be provided in the response to the 1R15 90-day outage report, as stated in the NRC letter. This BVPS Unit 1 report will be provided in another transmittal.

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There are no new regulatory commitments in this letter. If there are any questions concerning this matter, please contact Mr. Larry R. Freeland, Manager, Regulatory Affairs/Performance Improvement at 724-682-5284.

Sincerely,

L. William Pearce

Attachments

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Central File - *Keywords: Tube Inspection*

Letter L-03-110 - ATTACHMENT A

Information in Response to a Request for Additional Information
for Beaver Valley Power Station, Unit No. 2

Enclosure 1 to NRC letter dated June 4, 2003

1. NRC RAI

In enclosure 2 to the May 7, 2002, letter, the eddy current examination section indicates that the +Point probe was used to inspect 100% of the dents greater than 5 volts. In addition, it indicated that the +Point probe was used to inspect 20% of the dents and free-span dings with voltages greater than 2 volts but less than 5 volts if located between the hot leg top-of-tubesheet and the third hot leg support plate. However, in another document, (ADAMS accession number ML022670422) it was indicated that a 20% sample was performed on hot leg dents with voltages greater than 2 volts but less than 5 volts at the top of tubesheet, 02H, 03H, and 04H. Please clarify the scope of the dent and ding examinations (for dents and dings greater than and less than 5 volts).

FENOC Response:

The steam generators at BVPS Unit 2 are Westinghouse Model 51M design. This design incorporates a flow distribution baffle (FDB) located approximately 18 inches above the secondary side face of the tubesheet. The FDB is a partial plate with a "cut-out" in its center whose purpose is to direct downcomer flow to the center of the bundle in order to optimize blowdown effectiveness. The FDB on the hot leg side is designated as 01H. The first three "full" support plates are designated as 02H, 03H and 04H.

The reference to 02H, 03H and 04H in ADAMS document ML022670422 signified the first three (3) "full" support plates in the BV Unit 2 steam generators. The dent inspection performed at BV Unit 2 as part of the 2R09 inspection is as follows:

- 100% of all dents greater than 5.0 volts
- 20% of the dents greater than 2.0 volts but less than 5.0 volts if located between the hot leg top-of-tubesheet and the third "full" hot leg support plate (04H).

The ding inspection performed at BV Unit 2 as part of the 2R09 inspection is as follows:

- 20% of all dings greater than 5 volts located in the hot leg straight length 6" above top-of-tubesheet to the U-bend were inspected with the +Point probe.

- 20% of all dings greater than 2.0 volts but less than 5 volts from 6" above hot leg top of tubesheet (TTS) to the third "full" hot leg support (04H) were inspected with the +Point probe.

2. **NRC RAI**

A cold leg free span indication located at R26C81 (row 26, column 81), with a 16-degree phase angle was identified in steam generator SG21B during 2R09. Provide more detail on this indication including any available historical information.

FENOC Response:

A bobbin indication was reported in SG B, R26 C81 at 05C +15.9". The bobbin phase and amplitude response in the 400 kHz differential channel were 16° and 0.43 volts. This location was tested using +Pt at the 2R09 outage, with no degradation reported. This tube was left in service as a result of the +Pt analysis. This indication was also RPC tested at the 2R05 outage, with no degradation reported. Review of the history data for this signal in previous outages revealed minimal change in the signal characteristics through 2R09. The 2R07 and 2R08 analysis guidelines utilized the 200 kHz differential channel. The 2R07 and 2R08 phase responses were 79 and 68 degrees. Using the 200 kHz differential channel for the 2R09 data the phase is reported at 53 degrees. The 2R06 analysis guidelines utilized the 100 kHz differential channel. The 2R06 phase response was 85 degrees. Using the 100 kHz differential channel for the 2R09 data the phase is reported at 72 degrees. Thus, this signal experienced small levels of phase change over the past 4 inspections, however, the 2R09 +Pt inspection showed no degradation.

3. **NRC RAI**

It was indicated that three tubes in Row 2 were plugged due to U-bend restrictions. What was the smallest probe that did not pass through the tube? Did these tubes have a prior history of denting in the U-bend region? What was the largest probe size (bobbin or rotating probe) that ever passed through the tube? Discuss what actions were taken to identify the cause and nature of the restriction.

FENOC Response:

During 2R09 one tube in SG A and 2 tubes in SG B were plugged due to restrictions in the U-bend region. In all cases, the +Pt probe diameter was 0.680". The U-bend region in Row 2 tubes are not tested with the bobbin coil since all Row 2 tubes U-bends are inspected with +Pt. For these tubes, the probe translation through the U-bend was irregular, that is, the probe skipped due to localized conditions rendering the quality of the +Pt inspection data below the level required to perform analysis. No denting was reported at the top of tube support plate (TSP) in any of these tubes, therefore, there is no potential of flowslot hourglassing affecting the primary water stress corrosion cracking (PWSCC) susceptibility of these tubes. Two of these 3 tubes had been tested multiple times at the 2R08 inspection in order to achieve acceptable data for analysis. Thus, a history of inspection difficulty exists for these tubes. No actions were taken to identify the cause and nature of the restriction due to the nature of the inspection. The small radius bends of Row 1 and 2 U-bends sometimes require multiple tests to achieve a scan that can be analyzed from support to support. This is merely a result of the geometry and represents no underlying generic issue. Many factors can influence this test; age of the probe used, conduit lay from the probe pusher to the tube entrance, robot positioning, etc. Considering the geometry of the area inspected and the many factors that could influence probe translation through these small radius bends, such investigation would not reveal information of use.

4. NRC RAI

Please trend the number of distorted support plate indications (DSIs) at tube support plate intersections over time. Provide a summary of the growth rate for those indications with time. For the DSIs that were confirmed as flaws with the +Point probe, discuss the history of these indications. Compare the percentage of DSI indications showing measurable growth to the percentage of DSI indications that had a flaw identified by +Point examination. Discuss what actions, if any, have been taken to investigate the reason for the high percentage of DSIs that do not confirm as flaws during the +Point examination.

FENOC Response:

Table 1 presents a summary of the DSI population reported at 2R09. The maximum amplitudes reported are slightly larger, but in general, consistent with the last BVPS Unit 2 inspection. Compared to the 2R08 inspection, the number of indications > 1.0 remained approximately equal, while the total number of indications rose slightly (330 at 2R09 vs 279 at 2R08).

Table 1
BVPS 2R09 DSI Summary

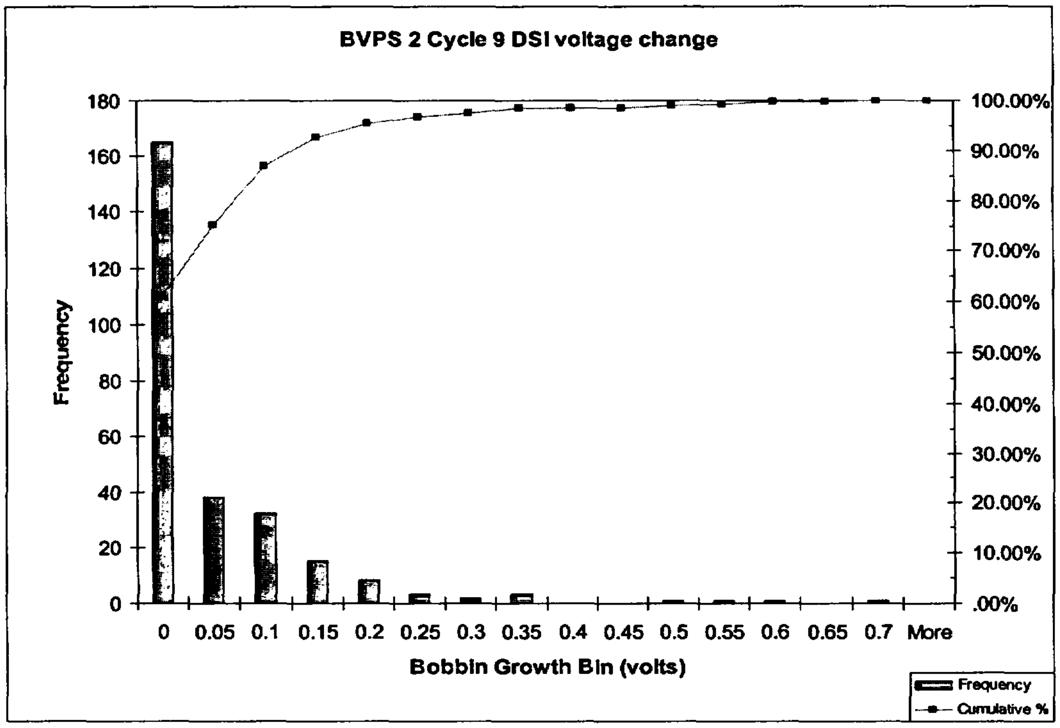
	SG A	SG B	SG C
Number Indications	93	167	70
Number ≥ 1.0 volt	4	8	4
Number ≥ 1.5 volt	0	1	0
Number ≥ 2.0 volt	0	0	1
Max 2R08 Voltage	1.32	1.97	2.41

The only DSIs out of the 330 reported that were confirmed by +Pt were found in SG B. There were four (4) DSIs confirmed by +Point which represents approximately 2.4% of the total number of DSIs in SG B and only 1.2% of the total number of DSIs identified in all three steam generators. The largest confirmed DSI bobbin coil probe voltage was 0.63 volts. Its corresponding +Point probe voltage was 0.14 volts. All had no reportable DSI amplitude in the 2R08 inspection data management records. Therefore, a comparison of DSI bobbin growth to +Point probe confirmation can not be made for the 2R09 DSIs confirmed by +Point probe.

An evaluation of DSI voltage growth was performed for Cycle 9 for SG B. On a per EFPY basis, the average DSI voltage change was 0 for Cycle 9. The upper 95% confidence growth was only 0.20 volts per EFPY and the single largest DSI voltage growth was 0.28 volts / EFPY. DSI phase angle change was also evaluated. The average DSI phase change was 2°, while the maximum DSI phase change was 50°. This evaluation shows that on average, the DSI population is essentially stagnant with regard to voltage change and phase change, suggesting that the growth of these signals during Cycle 9 was negligible.

Additionally, the overall DSI amplitude growth for BVPS 2 Cycle 9 is negligible. The largest singular bobbin amplitude growth in any SG was 0.70 volts, with an average growth of -0.03 volts. Figure 1 provides a cumulative probability distribution function of DSI growth for Cycle 9. An overwhelming majority of the growth values are within the typical repeatability bounds for the bobbin coil.

FIGURE 1



Industry and laboratory experience has indicated that deposits in TSP crevices can influence the normal bobbin coil probe response at TSP intersections. The DSI population at BV Unit 2 is indicative of support plate crevices packed with deposits. The DSI in and of itself, is not representative of degradation, however, it is recognized as a precursor condition that can foster TSP outside diameter stress corrosion cracking (ODSCC). Packed TSP crevices represent a condition conducive to TSP ODSCC due to adverse crevice chemistry conditions that occur with impurity concentration over time. Benefiting from BV Unit 1 experience with TSP ODSCC, BV Unit 2 implemented remedial chemistry controls early in its operation in an effort to avert significant TSP ODSCC. These remedial measures included boric acid addition and molar ratio control that aim at maintaining the crevice chemistry at a neutral state, thus avoiding ODSCC caused by caustic conditions. While these controls have not eliminated TSP ODSCC at Unit 2, it is believed they have been instrumental in limiting the proliferation of TSP ODSCC.

DSIs can be associated with packed crevice conditions and reflect the influence of deposits on the bobbin coil response. The +Point probe is capable of discerning stress corrosion cracking (SCC) degradation in the presence of a distorted signal at a TSP. If the +Point probe does not identify the presence of SCC, it is postulated that no SCC is present or if it is present, it is below the threshold of detection of accepted eddy current technology and does not represent a structural or leakage integrity concern.

The following table presents a historical summary of bobbin DSI signals at BVPS Unit 2 for the 2R07, 2R08, and 2R09 outages.

BVPS Unit 2 DSI Summary for Last Three Inspections			
	2R07	2R08	2R09
Total number of DSIs	277	279	330
Average DSI amplitude by bobbin	0.56 volts	0.63 volts	0.59 volts
Maximum DSI amplitude by bobbin	1.22 volts	1.82 volts	2.41 volts
Number DSIs $\geq$ 1 Volt	5	16	16
Number of +Pt Confirmed DSIs	0	1	4
Maximum bobbin amplitude of +Pt confirmed indications	N/A	1.06 volts	0.63 volts
Maximum +Pt amplitude of confirmed indications	N/A	0.14 volts	0.15 volts
Average DSI voltage growth per cycle	-0.12 volts	0.05 volts	-0.03 volts
95^{th} percentile DSI voltage growth per cycle	0.20 volts	0.35 volts	0.20 volts

5. NRC RAI

The BVPS Tube Plug Special Report (L-02-018) states: "Examination of the 'A' steam generator (2RCS-SG21A) used to meet the Technical Specification surveillance resulted in a total of eighteen (18) tubes being removed from service." Please clarify this statement.

FENOC Response:

The BV Unit 2 Technical Specifications state that inservice inspection of the steam generators may be limited to one steam generator on a rotating schedule encompassing 9% of the tubes if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Since it has been demonstrated that the BV Unit 2 steam generators are performing in a similar manner, per Technical Specifications, only 9% of the tubes in a single steam generator would be required to be examined.

Although FENOC inspects 100% of all active tubes in each steam generator every outage per EPRI Guidelines in order to ensure structural and leakage integrity and component reliability, one steam generator on a rotating schedule is designated as the initial inspection sample to demonstrate compliance to Technical Specification surveillance requirements.

The referenced statement in the NRC RAI reflects the results of the inspection of steam generator 2RCS-21A that was the "designated" steam generator at 2R09 for Technical Specification sampling purposes.

The steam generator inspections performed at 2R09 fulfilled the requirements of the EPRI Guidelines and encompassed multiple examinations of 100% of all active tubes in each steam generator. To reiterate, these examinations were performed to ensure structural and leakage integrity as well as component reliability and are independent of the Technical Specification steam generator surveillance sampling requirements.

6. **NRC RAI**

Please explain the use of the indication codes WAR and PCT. Some tube locations have both codes while others only have a WAR or PCT code. For example, in steam generator SG21B, R34C57 at AVB2, there is both a WAR and PCT code. For R35C54 at AVB1, there is only a PCT call and for R36C63 at AVB1, there is only a WAR. In BVPS-1, there was a zero (0) PCT indication code at a cold leg support location. Please clarify this nomenclature.

FENOC Response:

For antivibration bar (AVB) wear degradation, percent through wall (PCT) calls of wear indications are made from bobbin coil probe data. FENOC has implemented a supplemental +Point examination of a sample of AVB wear indications called from bobbin coil probe to ensure that crack-like indications are not present at the wear scar location. The +Point probe code at sampled AVB locations with the absence of crack-like indications would be WAR (wear). Thus, a PCT code at an AVB location designates the call made from bobbin coil. The WAR code would be the call made from the +Point probe at a sampled AVB location. Since the +Point probe was a sample inspection, not all bobbin coil probe calls (PCT) made at an AVB location will have a corresponding +Point probe call (WAR).

In regards to tube R36C63 referenced in the NRC RAI, a +Point probe examination was performed at the AVB locations due to a bobbin probe call made at AVB 2 and 3. +Point probe data was also gathered at the AVB1 location even though there was no bobbin probe call. The +Point probe revealed a potential incipient wear indication at AVB1 that is below the threshold of detection of the bobbin coil. Thus, there is no bobbin coil probe PCT call associated with the +Point WAR call.

The +Point sample examination of AVB wear calls made from the bobbin coil data did not reveal any evidence of crack-like indications.

Reference was also made in the NRC RAI to a BVPS-1 PCT call that was zero (0) percent through wall. No reference to a particular BVPS-1 document was provided in the NRC RAI, therefore, it is assumed the reference is made to a 1R15 steam generator inspection submittal. As the RAI reference is made to a cold leg support location, it is assumed that this reference is made to a cold leg thinning report. Cold leg thinning depth reports from bobbin coil sometimes result in a 0% through wall (TW) report based on the phase angle analysis for that particular location. These reports are associated with very small amplitude bobbin signals that could represent very shallow thinning depths.

Information in Response to a Request for Additional Information
for Beaver Valley Power Station, Unit No. 1

Enclosure 2 to NRC letter dated June 4, 2003

1. NRC RAI

BVPS Steam Generator Examination Report dated May 7, 2002, indicates four full-length tubesheet sleeves had collapsed and were obstructing tubes during 1R14. These sleeves had been installed during 1R13. The degradation mechanism was reported to result from a "flow diode" effect. An evaluation for BVPS-1 recognized the potential for additional sleeves to collapse and concluded that the structural integrity of the sleeve weld and mechanical roll will not be jeopardized. What is the basis for this conclusion? Have more collapsed sleeves been detected during 1R15? How has the potential for tube sleeve collapse been accounted for in evaluating the percentage of total tube population plugged (which affects thermal-hydraulic analysis in the plant design/licensing basis)?

FENOC Response:

Four sleeves were found to be collapsed at 1R14. Visual examination indicated the sleeves had experienced a localized dimpling that progresses no further than the sleeve axis. The elevation of the collapse was the approximate mid-point of the sleeve length, at approximately 15" above the tube/sleeve end, within the tubesheet region. A structural evaluation was performed based on tube to sleeve crevice internal pressures sufficient to cause collapse, combined with sleeve strain effects due to Poisson contraction, and concluded that these combined loads would not cause the weld to be stressed past yield, nor would axial loads exceed the hardroll joint breakaway load.

One additional sleeve was found to be collapsed at 1R15.

The flow diode phenomenon has been previously reported in the industry. It has been typically associated with the first inservice examination after sleeve installation. The BVPS results are consistent with industry experience. The current tube plugging analysis supports 30% tube plugging or to the plugging level that maintains RCS minimum thermal design flow. Sleeves are installed only in SG A and SG B. Conservatively assuming all of the tubes with installed sleeves were completely restricted due to collapse of the sleeves, the resulting effective total plugging in SG A and SG B would remain below the 30% analyzed plugging limit. It should be noted that remote visual inspection of the collapsed sleeves has verified that there is localized inward bulging, but not total restriction and substantial flow would be maintained through the tube even when the sleeve is considered "collapsed". Therefore, it is postulated that RCS minimum thermal design flow would also be maintained if significant numbers of sleeves were to collapse. Historical information, as well as BVPS 1R14 and 1R15 data suggest that no further collapsed sleeves will be identified at 1R16.

2. **NRC RAI**

During the 1R14 outage, one hundred hot leg tube support plate residual signals in each steam generator with amplitudes large enough to mask a 1.0 volt indication were reexamined with +Point probes. For cases where the +Point probes identified a flaw, the bobbin coil 200 kHz frequency was used to establish a distorted support indication (DSI) amplitude in the mix channel. Please clarify how flaws at these locations were dispositioned. The Nuclear Regulatory Commission staff notes that Generic Letter (GL) 95-05, Attachment 1, paragraph 1.b.3, states the voltage-based repair criteria "do not apply to intersections at which there are mixed residual [signals] of sufficient magnitude to cause a 1.0 volt ODSCC [outer diameter stress corrosion cracking] indication (as measured with the bobbin probe) to be missed or misread." Approximately how many residual signal indications large enough to mask a 1.0 volt indication have been detected in each SG thus far in 1R15? Within that population of indications, how many are flaw-like? How are the mixed residual indications being dispositioned?

FENOC Response:

Computer data screening (CDS) parameters are set to identify support plate residual (SPR) eddy current responses with amplitudes greater than 1.5 volts at the tube support plates (TSPs). SPR indications flagged by CDS undergo manual analysis to determine (1) if the SPR code is valid, (2) if further evaluation with the +Point probe is warranted, or (3) whether the SPR indication should be changed to a distorted support indication (DSI). Enclosure 3 to the NRC letter dated June 4, 2003 requested additional information regarding the subject of mixed residual signals and their disposition. This additional information will be provided in the 1R15 GL 95-05 90-day report and will be discussed in detail therein.

3. **NRC RAI**

BVPS 1 uses a number of data analysis codes for tube support plate indications (e.g. confirmed support indication, CSI, DSI, and possible support indication, (PSI)). Please clarify the criteria used to differentiate between a DSI and PSI code and how each type of indication, CSI, DSI, and PSI, is dispositioned according to the criteria established in GL 95-05.

FENOC Response:

DSI is a distorted support plate signal from bobbin coil analysis that could represent axial ODSCC in the tube at a TSP intersection. PSI is a possible tube support indication from bobbin coil analysis that could represent a condition associated with the tube support itself such as flow hole misdrilling that results in either a locally thinned tube hole ligament or partially missing ligament. Rotating Pancake Coil (RPC) is used to confirm the presence of such tube support conditions and estimate the amount of "missing" ligament arc length. If missing plate material is found by RPC, the PSI is changed to CSI (Confirmed Support Indication). The RPC estimated missing ligament arc length value is compared against a threshold limit determined by analysis that considers the amount of material that is required to be removed to permit the tube to escape from the tube hole. All PSI/CSI indications are excluded from Alternate Repair Criteria (ARC) application.

4. **NRC RAI**

A 20% random sample of the cold leg top-of-tubesheet region was examined during 1R14 (presumably using 3-coil +Point probes). Some indications were detected and repaired by tube plugging. Please clarify the type of indications that were found. How many tubes have been examined with the +Point probe at the cold leg top-of-tubesheet location during 1R15? How many and what types of cold leg top-of-tubesheet indications have been detected during the current outage?

FENOC Response:

All 1R14 cold leg top of tubesheet indications were associated with loose part wear or wear due to sludge lance rail interaction. The sludge lance equipment used at 1R13 and 1R14 was not used at 1R15. The 1R14 inspection program included a 20% sample of the cold leg top-of-tubesheet region in all three SGs, concentrated within the historical sludge deposition area since all hot leg ODSCC indications have been located within sludge deposition zones. The 1R15 inspection program included a 20% sample of the cold leg top-of-tubesheet region in SG A. No cold leg indications were reported at 1R15.