FENOC

FirstEnergy Nuclear Operating Company

5501 North State Route 2
Oak Harbor, Ohio 43449

Mark B. Bezilla
Vice President - Nuclear

419-321-7676
Fax: 419-321-7582

Docket Number 50-346

License Number NPF-3

Serial Number 3016

January 7, 2004

United States Nuclear Regulatory Commission
Document Control Desk
Washington, D. C. 20555-0001

Subject: Response to Questions Regarding the 2002 Steam Generator Tube Inspections (TAC No. MB9541)

Ladies and Gentlemen:

By letters dated March 22, 2002 (Serial Number 2771), and March 31, 2003 (Serial Number 2944), the FirstEnergy Nuclear Operating Company (FENOC) reported the results of the Davis-Besse Nuclear Power Station (DBNPS) 2002 steam generator tube inspections. By letter dated November 3, 2003 (Serial Number 2989), FENOC responded to an NRC request for additional information regarding the 2002 steam generator tube inspections. By letter dated December 11, 2003, the NRC provided thirteen additional questions (Log Number 6141). Responses to five of these questions were provided by letter dated December 17, 2003 (Serial Number 3013). Responses to the remaining eight questions are provided in Attachment 1 to this letter.

Should you have any questions or require additional information, please contact Mr. Kevin L. Ostrowski, Manager - Regulatory Affairs, at (419) 321-8450.

Very truly yours,

MAR

Attachments

A001

cc: Regional Administrator, NRC Region III
J. B. Hopkins, DB-1 NRC/NRR Senior Project Manager
C. S. Thomas, DB-1 NRC Senior Resident Inspector
Utility Radiological Safety Board

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION DAVIS-BESSE NUCLEAR POWER STATION 2002 STEAM GENERATOR INSPECTION (TAC NO. MB9541)

Question #1:

Regarding the inspection of the peripheral tubes to inspect for changes in the gap between the tubes and the secured auxiliary feedwater (AFW) header to verify that the header has not moved, it was indicated that 100 percent of the inservice periphery tubes were inspected. In addition, it was indicated that gap measurements were made for several AFW header indications.

Discuss how many tubes in each steam generator were examined as part of this inspection. Please discuss when a gap measurement is made for these tubes. Discuss in detail how it was verified that the AFW header has not moved. For example, were the 2002 gap measurements compared to the gap measurements taken when the AFW header was secured? Discuss the basis for the 0.250-inch criteria mentioned in your November 3, 2003 letter. Discuss the results of the visual inspection (visual inspection required per TS 4.4.5.8) of the AFW header.

It was indicated that two tubes were plugged as a result of dents associated with the AFW header. Clarify when these dents were identified and whether they have changed in size with time. If they have changed with time, discuss what impact, if any, it has on your assessments that verify the AFW header has not moved in operation. Discuss the causal mechanism for the denting.

Response:

In 1981, a tube leak was experienced by the Davis-Besse Nuclear Power Station (DBNPS). Eddy current testing and visual examinations revealed that the internal AFW headers and the brackets that attached them to the upper steam wrapper were damaged. This degradation resulted in damage to some of the peripheral once-through steam generator (OTSG) tubes due to movement of the internal header during plant operation. The AFW internal headers were subsequently stabilized and functionally replaced by external headers. No movement or new indications of tube degradation caused by internal header movement have been noted since the internal AFW headers were stabilized.

The auxiliary feedwater header (AFH) analysis is performed on 100% of the in-service periphery tubes during each outage using a site-specific qualified bobbin coil technique. The analysis is performed by a specially trained analyst(s) using the bobbin probe data and a special calibration method. The data is reviewed for the presence of a header signal and the gap is estimated for each indication detected. When the gap is greater than 0.250", it is beyond the ability of the technique to accurately measure and no measurement is made. In this case, a signal may be present, but the amplitude is too small and is outside the bounds of the established calibration curve. Additionally, because of their low signal amplitude, it is somewhat subjective as to whether they are reported by the analyst or not.

During the 13th Refueling Outage (13RFO), the AFH inspection scope included all in-service peripheral tubes in both OTSGs (395 tubes in OTSG 2-A and 427 tubes in OTSG 1-B). AFH signals were detected in 12 tubes in OTSG 2-A and 4 tubes in OTSG 1-B with all of the estimated gap measurements greater than 0.250". This is a slight increase (3 in 2-A and 4 in 1-B) in the number of tubes with indications reported in the 12RFO inspection, but this is not a reason to believe that the AFH is actually moving towards the tubes. Since there is no reporting criteria for these indications, reporting is made at the detection threshold. Reporting at this low level means screening the NDE data for very small signals that barely exceed the background noise inherently in the tube. Analysis of this type leads to some minor variations in analyst disposition thresholds and affects whether indications are reported or not. In the case of these new indications, the signals were detectable in the 13RFO data and thus were reported. More importantly is the fact that there was no change in the gap measurements for the indications that were reported in 12RFO and 13RFO (all still >0.250"). This indicates that there was no relative change in the AFH position during the cycle and there is no integrity issue with tubes where the AFH signal was detected.

Eddy current examinations of peripheral tubes in the DBNPS steam generators are performed at each scheduled outage to monitor tube integrity. The internal AFW header and supporting welds are visually inspected each 10-year inservice inspection (ISI) interval per Technical Specification 4.4.5.8. Inspections in 1990 and 1998 showed no evidence of movement or degradation of the AFW header or degradation of the AFW supply nozzles and thermal sleeves. One AFW nozzle was stuck in 1998 and the header at this nozzle was inspected in 2000 with no evidence of movement or change in the header at this location.

The two tubes plugged as a result of degradation at dents associated with the AFH were tubes B-63-128 (OTSG 1-B, Row 63, Tube 128) and B-95-128, that had indications of axial outside diameter stress corrosion cracking (ODSCC), as provided in response to Question 1 in the letter dated November 3, 2003 (DBNPS Serial Number 2989). These dents are also two of the dents discussed in the Question #9 response below. These dents were not reported by bobbin coil since they were below the reporting criteria of 2.5 volts, but were inspected with a 0.115" pancake probe to evaluate the dent signal (see Question #9 below). A review of the historical bobbin coil data for these dents indicates that they were present in previous inspections, at the same height as the top of the AFH box, and are not changing with time. The dents were obviously caused by the AFH prior to its repair in 1981 and are not an active mechanism.

Question #2:

It was stated that no fatigue degradation was discovered in either steam generator during the 2002 refueling outage in the one row of unsleeved tubes bordering the sleeved portion of the lane/wedge region (i.e., the sleeve border locations).

Clarify how the determination was made that no fatigue degradation was present. For example, was it based on not detecting any degradation in these tubes or was it based on not detecting any circumferential indications in these tubes? If circumferential indications were found in these tubes, discuss how it was determined that these circumferential indications were not induced by fatigue.

Response:

The inspection area for fatigue cracking in the lane/wedge region is defined in the DBNPS Degradation Assessment, as the one row of unsleeved tubes that borders the sleeved portion of the lane/wedge region. All OTSG plants perform an inspection of this region with +Point to determine if crack-like indications, which may be indicative of fatigue, are present. Detection of this type of degradation may indicate a need to sleeve or plug additional tubes adjacent to the existing wedge region.

During the 2002 refueling outage, only non crack-like degradation was identified in two tubes within the subject inspection area. One tube (A-79-33) had an outside diameter (OD) volumetric indication (27% through-wall (TW) single volumetric indication (SVI) @ the upper tube sheet (UTS) + 5.33") confined within the tubesheet region and attributed to OD intergranular attack (IGA). The other tube (B-68-3) had an OD volumetric indication (8% through-wall defect (TWD) @ 15th support plate (15S) - 0.66") attributed to wear at the support plate. All other tubes in the border inspection were found to have no detectable degradation (NDD). The determination that no fatigue degradation was present was based on the absence of any crack-like indications (axial or circumferential) in these tubes.

Question #6:

An examination of dents at or above the 14th tube support plate revealed 18 new and repeat dents in SG 2-A and 21 new and repeat dents in SG 1-B.

Clarify how many of these dents were new (reported for the first time)? If these dents are not traceable back to the preservice inspection, discuss what affect this active denting mechanism could have on tube integrity for the period of time between inspections.

Response:

A query of these dent indications shows that five (5) of the eighteen (18) dents in OTSG 2-A and nine (9) of the twenty-one (21) in OTSG 1-B did not have a corresponding dent call in the 12RFO inspection results. However, of the five new calls in SG 2-A, two were in the upper end of an installed sleeve, and one had been previously detected in 11RFO. Thus only two (2) of the dents in SG 2-A were newly reported tube dents. Of the nine new calls in SG 1-B, eight were new and one was previously detected and reported in 11RFO. The two dents listed with INR (Indication Not Reportable) in the "comment" column of the Table below indicate that a dent was called in 11RFO and then because it measured less than 2.5 volts in 12RFO, it was not reported. It is not uncommon for slight variations in voltage to occur from outage to outage, thus affecting whether the indication is reported or not.

None of the dent indications in tubes were >3 Volts, had indications of cracking by rotating coil examination, or were associated with the AFW header region. The inspection data from previous outages was reviewed for all of the dents in question and it was determined that the 10 dents in tubes referred to as "new" in 13RFO were present back to at least 8RFO (earliest optical disk data available), but unreported until 13RFO. The dent signal magnitudes in these cases were close to the reporting threshold of 2.5 volts and as such were not reported prior to the 13RFO inspection. In the case of the two dents in the sleeves, the pre-service inspection data was also reviewed and indicated the presence of these signals also. Therefore, none of the dents was newly formed, and there is no evidence that denting is actively progressing in the DBNPS OTSGs. The Table below presents the 13RFO details of each signal.

Table 1: Newly Reported Dents in 13RFO

OTSG	Row	Tube	Location	Inch	Voltage	Comment
2-A	57	7	15S	+38.55	2.5	Previous INR at 2.44 V
2-A	73	61	UTS	+0.13	2.52	
2-A	75	60	UTS	+0.08	2.62	
2-A	69	1	UTS	+19.56	10.27	In Sleeve
2-A	79	1	UTS	+19.55	2.96	In Sleeve
1-B	36	48	UTS	+6.27	2.5	
1-B	48	72	15S	+44.41	2.63	Previous INR at 2.39 V
1-B	76	65	UTS	+0.09	2.56	
1-B	77	48	UTS	-0.06	2.55	
1-B	77	64	UTS	+0.09	2.54	
1-B	78	64	UTS	+0.09	2.79	
1-B	79	66	UTS	+0.14	2.76	
1-B	80	66	UTS	+0.11	2.64	
1-B	145	28	14S	+13.44	2.75	

<u>Question #8:</u>

A number of tubes with volumetric indications attributed to intergranular attack were plugged. Several of these indications were near 60 percent through-wall.

Discuss the growth rate for these indications and discuss whether an increase in growth rate has been occurring with time (if a growth rate can not be established, discuss whether the maximum and/or average depths observed during an outage has been increasing with time). If the growth rate (or maximum and average depths of the population of indications) has been increasing, discuss the implications to your tube integrity assessments.

Response:

The end-of-cycle severity of volumetric indications exhibits an overall downward trend at the DBNPS. This is illustrated in Figure 1, which shows that the cumulative distribution of +Point voltages is shifting towards lower values; and in Figure 2, which shows that the average and upper 95th percentile voltages are lower for 13RFO than for the previous two inspections.

Figure 3 shows that voltage is a better indicator of degradation severity than a non-destructive examination (NDE) phase angle maximum depth estimate, consistent with the data that was originally provided in response to Question #1 and discussed in response to Question #12 of the letter dated November 3, 2003 (DBNPS Serial Number 2989). Phase angle depth NDE measurement error increases markedly at lower voltages. Phase angle depths are more reliable for higher voltages. Figure 3 shows that reported phase angle depths near 60%TW are basically a reflection of increased depth sizing error rather than an indicator of significant degradation severity. Volumetric degradation severity at the DBNPS is relatively mild and is on a decreasing trend as a result of the repair on detection management of these indications and the relatively good bobbin coil probability of detection (POD).

Because of the low signal amplitudes of the indications during 13RFO, determination of depth based growth rates is highly problematic. Additionally, back-to-back +Point is not available in most instances since a bobbin non-quantifiable indication (NQI) is first required to trigger a follow up examination with +Point. A good, conservative estimate of the growth rate of volumetric degradation is provided from 12RFO NDE data, with look-back sizing for corresponding 11RFO data. Figure 4 shows the growth rate analysis results. A computer simulation of NDE sizing errors was used to generate a best estimate of the actual physical growth rates. When the influence of NDE sizing errors is removed, the upper 95th percentile growth rate is estimated at

12%TW/Cycle, maximum depth. When NDE sizing errors are included, the apparent upper 95th percentile NDE depth based growth rate is 24%TW/Cycle, maximum depth. Neither value presents a challenge to structural or leakage integrity at end of cycle (EOC) conditions at the DBNPS.

Figure 1: Cumulative Distribution of Plus Point Voltages of Volumetric IGA Indications for the Past Three Outages at Davis-Besse

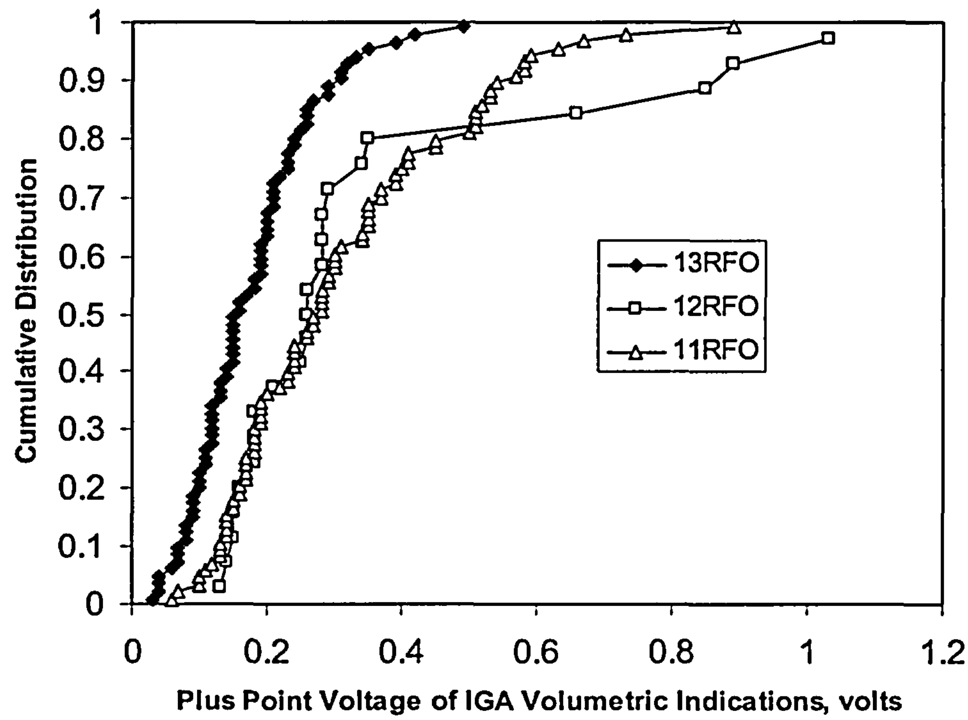


Figure 2: Average and Upper 95th Percentile Plus Point Voltages of Volumetric IGA Indications at Davis-Besse versus Outage Number

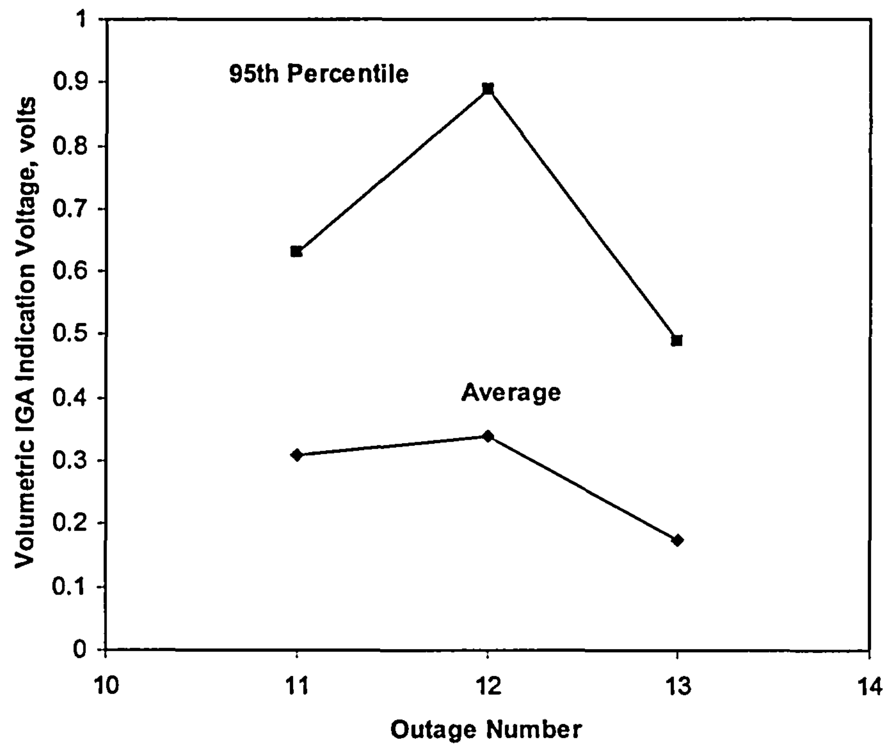


Figure 3: NDE Phase Angle Maximum Depth versus Plus Point Voltage, Volumetric IGA Degradation at Davis-Besse

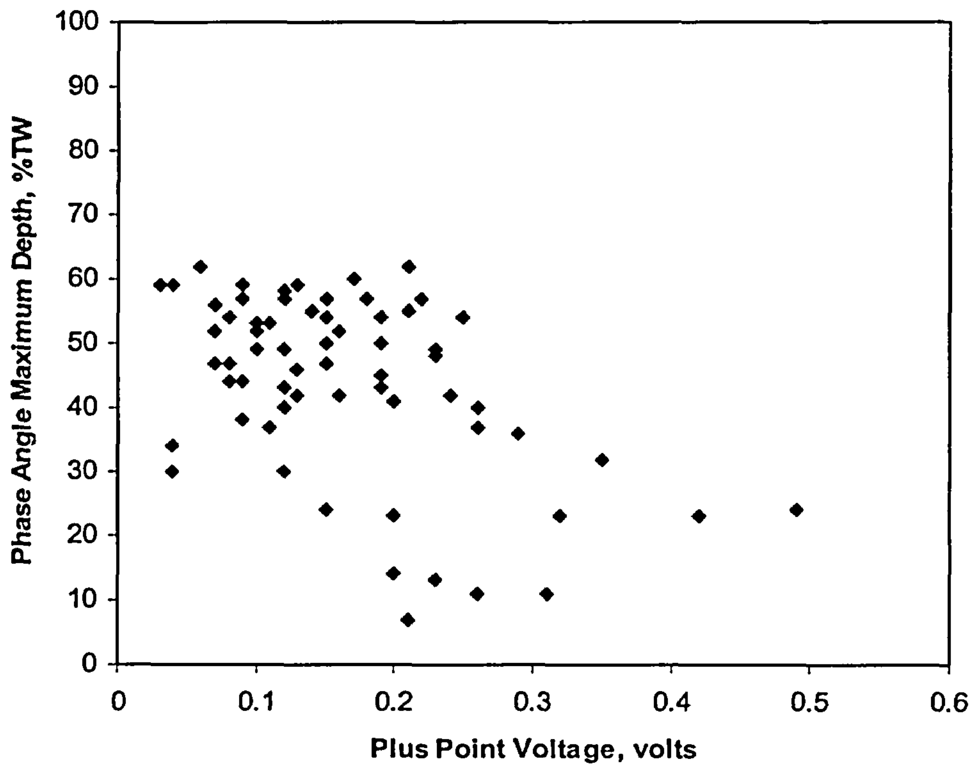
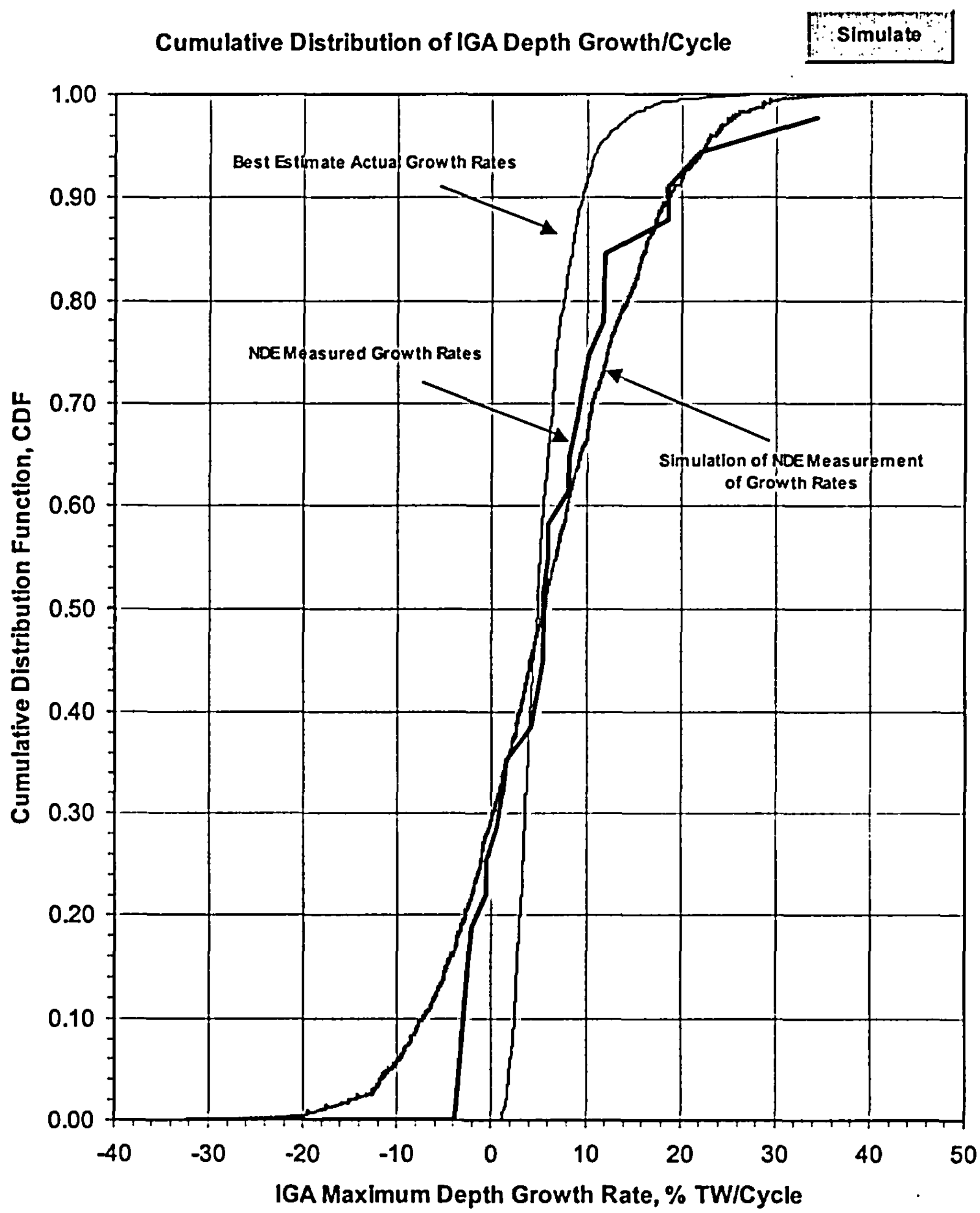


Figure 4: Matching Results for NDE Measured Growth and Computer Simulation of NDE Measured Growth, Comparison with Actual Volumetric IGA Depth Growth, Davis-Besse 11RFO to 12RFO



Question #9:

It was indicated that 3 of the 194 dents in SG 1-B were identified with the pancake coil.

Please discuss why these dents (presumably greater than 2.5 volts as determined by the bobbin coil) were not identified during the original bobbin screening. Also, discuss the implications of not finding these dents with the bobbin coil given that cracking has occurred at dents.

Response:

The three dents (DNT) were detectable, but not reportable, with the bobbin probe. The bobbin probe data provides evidence of a dent in all three cases; however, the signal amplitudes are much lower than the 2.5 Volts peak-peak (Vpp) bobbin reporting criteria (the bobbin amplitudes were: 0.97 Vpp, 0.64 Vpp, and 0.92 Vpp). Rotating pancake coil voltage for these same dents was 3.58, 3.00, and 4.16 Vpp, respectively, as listed in the response to Question #1 of the letter dated November 3, 2003 (DBNPS Serial Number 2989). Because the bobbin signals also displayed flaw-like characteristics, they were reported as non-quantifiable indications (NQI), and were subsequently tested with the rotating probe technique.

The DBNPS analysis guidelines provides requirements for the bobbin probe screening of all dents, regardless of whether the bobbin probe signal amplitude exceeds the reporting threshold. A more detailed discussion of these requirements is provided in the response to Question #10 in the letter dated December 17, 2003 (DBNPS Serial Number 3013). The fact that these dents were below the calling criteria is not significant since the bobbin coil also identified the presence of an indication that ultimately was classified as axial OD degradation by the +Point inspection of the region. The details of these indications were provided in the response to Question 1 in the letter dated November 3, 2003 (DBNPS Serial Number 2989).

Question #11:

It was reported that an exception was taken against one specific element of the EPRI PWR Steam Generator Examination Guidelines that requires the number of reported false calls be no more than 10% of the total number of unflawed grading units when grading a Qualified Data Analyst test. The licensee stated that not imposing the false call criteria assures a higher probability of detection, which should result in a more conservative position, thereby assuring a safe and reliable inspection process.

It appears to the NRC staff that this would be true provided the false call rate made during analysis of the field eddy current data was the same or higher than the false call rate made during the qualification test (i.e., to avoid an analyst making numerous false calls during the qualification test simply to pass the test).

Discuss what measures, if any, were taken to verify that the false call rate in the field were consistently higher than the false call rate made during the qualification test. In other words, explain why excluding the false call criteria assures a higher probability of detection for the individual qualified data analysts.

Response:

All data analysts who evaluate steam generator eddy current data at the DBNPS are qualified by examination as part of the industry Qualified Data Analyst (QDA) certification process. During this process, false call criteria are imposed.

In preparation for steam generator tube examinations at the DBNPS, analysts are provided with site specific training and are required to demonstrate their understanding of site specific characteristics and analysis requirements. In the site qualification tests, false call criteria are not imposed. Elimination of the false call criteria helps to establish the expectation and understanding among analysts that they are not to evaluate the importance of signals, but are instead to analyze and report signals in accordance with established criteria. With the knowledge that they are not expected to judge whether or not these indications represent true degradation, analysts will report a larger number of indications.

Analysts are not penalized for false calls in site qualification tests or in field analysis activities because of the potential that they may become less conservative as a result. Imposing false call criteria during the site-specific qualification may bias analysts' judgment away from calling indications that are marginal, yet flaw related. Eliminating the false call criteria from the data analyst test has the opposite effect, and will likely yield a higher POD.

No measures have been taken to verify that the false call rates in the field were consistently higher than the false call rates during the qualification test. The inspection process includes two-party eddy current analyst data review, use of analyst performance tracking for missed indications, and Independent Qualified Data Analyst (IQDA) review of indications discarded by the resolution process. This process provides confidence in the inspection results and validation of eddy current analyst performance. Therefore, the DBNPS believes that the inspection process used during 13RFO provides a detection POD that met or exceeded that required by the 13RFO Degradation Assessment.

Question #12:

It was indicated that the plant deviated from the portion of the EPRI guidelines dealing with chemical excursions that exceeded Action Level 3 limits.

Discuss whether this deviation was in effect prior to the 2002 outage and whether it currently is in effect. Discuss the corrective actions taken to minimize the potential to exceed the Action Level 3 limits. In addition, provide the technical basis demonstrating that the process followed when Action Level 3 limits are exceeded at Davis-Besse is the best course of action. Also, discuss why this is not recognized by the industry guidelines (i.e., is the phenomenon observed at Davis-Besse unique).

Response:

Prior to the 2002 outage, the DBNPS identified specific conditions under which the Electric Power Research Institute (EPRI) PWR Secondary Water Chemistry Guidelines relating to Action Level 3 limits would not be implemented. This exception was evaluated and documented in accordance with Nuclear Energy Institute (NEI) 97-06 expectations. The following discussion describes the exception and provides the basis for the conclusion that, under the applicable circumstances, this exception represents the best course of action to protect steam generator tube integrity.

The EPRI PWR Secondary Water Chemistry Guidelines requirement that "regardless of the duration of the excursion into action level 3, the plant should be taken to hot or cold shutdown," is not implemented by the DBNPS for short duration sodium excursions caused by secondary cycle transients. Instead, each feedwater excursion is evaluated on a case by case basis to determine the best course of action to minimize the integrated SG exposure to sodium. Should the sodium excursion last for greater than 120 minutes after reaching the EPRI guideline Action Level 3 value (but less than 12 ppb), the plant will be shutdown in accordance with EPRI guidelines as safely as possible.

Sodium excursions resulting from secondary system transients are not unique to the DBNPS. In general, this phenomenon occurs in OTSG plants due to the carryover of chemicals to the turbine cycle within the superheated steam. The Babcock & Wilcox Owner's Group (BWOG) is currently addressing this issue and is expected to include recommendations in the appropriate section of the next revision of the EPRI PWR Secondary Water Chemistry Guidelines.

Literal compliance with the current guidelines may not be the best response if feedwater sodium exceeds the 5 PPB Action Level 3 limit for brief periods. Unnecessary plant shutdown, cooldown and transients may be more damaging to the steam generators than continued operation after a short duration chemistry transient. Initiation of a plant shutdown due to a short-term sodium spike will result in additional sodium release from secondary side components including the steam generators, high pressure (HP) turbine and reheaters. This will expose the steam generator tubes to a higher integrated sodium load than would continued operation.

Sodium tends to concentrate in the dry steam portion of the steam generators, the Wilson line in the HP turbine and at the dry-out line within the reheaters. Redistribution of sodium within the steam and feedwater cycle is not sodium ingress to the system, but a re-equilibration of sodium within the system in response to changing steam quality, temperature and steam generator level. During short-term feedwater sodium increases resulting from redistribution within the system, appropriate plant action to identify the source and minimize total sodium ingress to the steam generators will minimize the impact on tube integrity.

Secondary system response to a power change, redirection of Moisture Separator Reheater (MSR) or heater drains to or from the condenser, T-ave reduction, turbine valve testing or switching the Integrated Control System (ICS) between manual and automatic control is fundamentally different than an increase in contaminant ingress from a source such as circulating water or turbine plant cooling water. Sodium ingress from a source such as circulating water will not be a short duration pulse input. This type of ingress will result in a broad, increasing trend in sodium, and a corresponding increase in cation conductivity. However, the pulse duration from changing plant conditions is generally short and commensurate with the magnitude of the plant change and preceding secondary side sodium history. This pulse does not have a corresponding increase in cation conductivity since the source sodium was deposited in the system at equilibrium locations.

The 120-minute allowable transient time at less than 12 ppb sodium ensures that the General Electric (GE) turbine steam chemistry limits (Action Level 2 of 12 ppb sodium) are not exceeded. Action Level 2 allows a plant 100 hours to reduce the contaminant below the Action Level value. With an Action Level 2 limit of 3 ppb sodium, 1.68 lbm of sodium would be transported to each steam generator during the 100 hours of power operation. A limit of 12 ppb sodium for 2 hours would only introduce 0.13 lbm of sodium to each steam generator.

In summary, for sodium excursions related to plant transients, a power reduction will release additional sodium from the steam and feedwater system, which in turn will result in a net increase in integrated sodium exposure to the steam generator tubes. Confirmation and characterization of the increase in sodium levels as redistribution, or as an ingress event, will permit conservative decision making with respect to shutdown or power reduction. Each feedwater excursion will be evaluated on a case by case basis to determine the best course of action to limit the integrated exposure to sodium.

Question #13:

It was indicated that there were no confirmed loose part indications detected by eddy current. Clarify what is meant by "confirmed". For *example, is it referring to visual confirmation of the indication? Discuss whether any possible loose parts were detected during the eddy current examination.*

Response:

No loose part indications were reported during the eddy current examination either in the bobbin screening or +Point diagnostic testing and no historical indications of possible loose parts during inservice conditions exist at the DBNPS. Confirmation of a loose part indication with eddy current is accomplished with the rotating probe (+Point, pancake coils) technique. No visual inspections of the OTSGs were performed at 13RFO. Loose parts and associated NDE signals are not typical in OTSGs, since the main feedwater nozzles nozzles have small holes in their spray heads that help prevent parts from entering the secondary side of the steam generators.

COMMITMENT LIST

The following list identifies those actions committed to by the Davis-Besse Nuclear Power Station (DBNPS) in this document. Any other actions discussed in the submittal represent intended or planned actions by the DBNPS. They are described only for information and are not regulatory commitments. Please notify the Manager – Regulatory Affairs (419-321-8450) at the DBNPS of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	DUE DATE
None	N/A