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Subject: Supplemental Information regarding License Amendment Application to Revise Technical Specification 3/4.4.5, "Reactor Coolant System - Steam Generators," to Permit One-Time Extension of Steam Generator Tube Inservice Inspection Interval (TAC No. MC1573)

Ladies and Gentlemen:

By letter dated December 16, 2003 (Serial Number 3000), the FirstEnergy Nuclear Operating Company (FENOC) submitted an application for amendment of the Operating License, Appendix A, Technical Specifications (TS) for the Davis-Besse Nuclear Power Station (DBNPS). The proposed amendment would revise Technical Specification (TS) 3/4.4.5, "Reactor Coolant System - Steam Generators," to allow a one-time extension of the steam generator tube inservice inspection interval. By letter dated January 23, 2004, the NRC requested additional information regarding the proposed amendment. The FENOC responses to this request are provided in Attachment 1.

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

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The statements contained in this submittal, including its associated attachments, are true and correct to the best of my knowledge and belief. I declare under penalty of perjury that the foregoing is true and correct.

Executed on: 1/29/04.

By:

Mark B. Bezilla, Vice President - Nuclear

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Attachments

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
REGARDING LICENSE AMENDMENT APPLICATION TO
PERMIT ONE-TIME EXTENSION OF STEAM GENERATOR
TUBE INSERVICE INSPECTION INTERVAL

Question #1:

The under prediction of the number of indications of volumetric intergranular attack (IGA) observed during the 2002 outage (refueling outage 13) was attributed to the chemical cleaning performed in the prior outage (i.e., refueling outage 12). Similarly, the under prediction of the number of indications of tube wear observed during the 2002 outage was attributed to a new eddy current technique and to the chemical cleaning. Please discuss the basis for your conclusion that chemical cleaning and the new eddy current technique resulted in detecting a larger number of indications during refueling outage 13 than anticipated. Ensure that your response addresses the following: (1) a discussion of when the chemical cleaning was performed in relation to the steam generator tube inspections during refueling outage 12 (e.g., if the chemical cleaning was performed prior to or during the steam generator tube inspections, wouldn't the inspection transient have been observed during refueling outage 12), (2) an assessment of tube noise prior to and following the chemical cleaning (since detectability is a function of noise and other interfering signals), (3) the nature of the new eddy current technique for detecting tube wear including an assessment of whether this new technique could be used to reanalyze the refueling outage 12 data (if it can be used, address whether the "new" indications were present during refueling outage 12).

Response:

(1) During the 2000 outage (12RFO), chemical cleaning (CC) was conducted after approximately 50% of the bobbin coil data was acquired in once-through steam generator (OTSG) 2-A, and after approximately 100% of the data in OTSG 1-B. By using the 12RFO outage schedule information and the sequence of inspections relative to when the CC was performed, the tubes that were inspected with the bobbin probe pre-CC and post-CC were estimated. The number of confirmed intergranular attack (IGA) indications in these populations was essentially equal in 12RFO; however, the majority of the confirmed indications (~62%) of IGA in 13RFO were in the population of tubes that was inspected with the bobbin coil prior to the cleaning in 12RFO. Additionally, the number of bobbin indications called in 13RFO in

the pre-CC population was also higher than the post-CC population.

These facts indicate that the bobbin coil probability of detection (POD) is affected in two ways. The first effect is the increase of POD in "real" indications (ones that would confirm by rotating coil inspections), while the number of false calls (indications that would not confirm) decreases. Therefore, the number of new confirmed IGA calls in the 13RFO inspection is not a result of degradation growth or an issue with the operational assessment (OA) method but is the result of improved POD of real flaws that were inspected in 12RFO prior to CC.

(2) For plants that chemically clean and use alternate plugging criteria to leave defective tubes inservice, an assessment of the effect of chemical cleaning on the growth rate and POD is typically required. This assessment is accomplished by inspecting a sample of flawed and unflawed tubes both before and after the cleaning. The Davis-Besse Nuclear Power Station (DBNPS) utilizes none of these alternate plugging criteria, but during 12RFO a small sample of tubes (18 indications that were confirmed as single volumetric indications (SVI) or wear with rotating coil) were re-inspected after CC in each OTSG to assess any improvements. In the cases of the four freespan IGA indications, none of the plus-point signals changed in the comparison. In the case of fourteen wear indications, nine of them were designated as "no degradation found (NDF)" after the CC and a review of the data indicated that the indications were likely deposits that were mis-characterized as wear. The five remaining wear indications were reconfirmed. Additionally, bobbin coil data was compared for some of the tubes in the 2-A OTSG where data was acquired before and after CC. This review identified a distinct signal on the tubes at the height where the CC solution level was on the secondary side (09S + 26") as well as differences between the Tube Support Plate (TSP) Lissajous patterns signals. Small amplitude bobbin differential signals continue to be seen in both OTSGs during each inspection. The indications are outside diameter (OD) and attributed to the introduction of service water into the secondary side of the OTSGs in the early 1980's. The indications have been inconsistently reported and confirmed throughout the years due to their small bobbin amplitudes and poor repeatability. During the 2002 (13RFO) outage, the indications were clearer and rotated slightly more into the flaw plane likely due to the lack of deposit signals that previously had been affecting the flaw response.

(3) During the 2002 (13RFO) outage, wear indications were depth sized with four different techniques (bobbin probe amplitude sizing, plus-point amplitude sizing (using only the axial coil response), plus-point amplitude sizing (using the combined coil response) and pancake coil amplitude sizing) to compare the depth estimates. From the study it was noted that bobbin probe amplitude sizing should be used to assign a depth for all wear indications and the plus-point amplitude sizing (using combined coil response) can be used to provide a depth estimate when a rotating coil technique is applied.

The new indications of wear that were detected in 13RFO were small in bobbin coil signal amplitude and response. Once the OD deposit was removed from the tubes, the signals were more discernable in the bobbin coil data. The sizes of the new wear indications from the bobbin coil data were all sized at $\leq$16% through-wall (TW). This experience has been the trend in other SGs that have been chemically cleaned. The technique could be used to identify the signals in the 12RFO bobbin coil data, but since the 13RFO sizes are relatively small, the effect on the projected growth for cycle 14 would ultimately decrease by adding these small growth data points to the distribution.

Question #2:

Your conclusion regarding the acceptability of your proposal is contingent upon maintaining satisfactory water chemistry during the storage and layup conditions subsequent to your assessment (which was through December 1, 2003). As a result, you provided a commitment to assure that the steam generator layup and storage conditions subsequent to the time period assessed in your submittal were consistent with the conclusions of that assessment. Given the importance of water chemistry during the shutdown period, discuss the need to incorporate this commitment as a license condition. In addition, discuss the need to incorporate a time period for the performance of this assessment (since the restart date is not specified). In other words, discuss the need for a license condition to perform an assessment within x days following plant restart of the actual steam generator water chemistry for the time period from December 1, 2003 until plant restart to verify that the chemistry control during the extended shutdown did not create conditions that would have an adverse effect on, or cause any type of known corrosion to, the steam generators during the shutdown period (i.e., the extended shutdown did not create conditions that would affect the integrity of the steam generators or their ability to perform their *intended safety function).*

Response:

NRC guidance on the escalation of a regulatory commitment into a license condition is specified in Section 4.4 of NRR Office Instruction LIC-101, *License Amendment Review Procedures,* Revision 2. This guidance states, in part, "The escalation of an action proposed by a licensee as a commitment into a license condition, requiring prior NRC approval of subsequent changes, should be reserved for matters that satisfy the criteria for inclusion in technical specifications by 10 CFR 50.36 or inclusion in the license to address a significant issue." FENOC does not believe that the commitment contained in the amendment application satisfies the criteria for inclusion in technical specifications or is necessary to address a safety significant issue. FENOC believes that existing regulatory controls on primary and secondary water chemistry are sufficient to assure that steam generator layup and storage conditions during the ongoing outage are appropriately monitored and controlled.

Reactor Coolant System (RCS) chemistry requirements were relocated from the Technical Specifications to the DBNPS Updated Safety Analysis Report (USAR) Technical Requirement Manual (TRM) by License Amendment No. 234, dated November 16, 1999. In its Safety Evaluation related to Amendment No. 234, the NRC stated:

> FENOC has proposed to remove TS [Technical Specification] 3/4.4.7, "Reactor Coolant System - Chemistry," from the TSs and relocate the requirements to the TRM. Poor coolant water chemistry contributes to the long-term degradation of system materials of construction, but is not of immediate importance to the plant operator. Reactor coolant water chemistry is monitored for a variety of reasons. One reason is to reduce the possibility of failures in the RCS pressure boundary caused by corrosion. However, the chemistry monitoring activity serves a long-term preventative rather than migitative purpose. Therefore, TS 3/4.4.4.7 does not meet any of the criteria in 10 CFR 50.36 and may be relocated to the TRM. Any changes to the requirements regarding the RCS chemistry, as relocated to the TRM, will be subjected to the requirements of 10 CFR 50.59. Thus, under 10 CFR 50.59, sufficient regulatory controls exist to ensure continued protection of the public health and safety.

Based on the safety evaluation for Amendment No. 234, primary water chemistry monitoring requirements do not satisfy the criteria for inclusion in the DBNPS Technical Specifications. RCS chemistry requirements are specified in TRM Section 3/4.4.4.7, which is applicable at all times. The limitations on RCS chemistry contained in the TRM ensure that corrosion of the RCS is minimized and reduce the potential for Reactor Coolant System leakage or failure due to stress corrosion.

Requirements for secondary water chemistry are already specified in the DBNPS operating license. Operating License Condition 2.C(5) requires FENOC to implement a secondary water chemistry monitoring program to inhibit steam generator tube degradation. This license condition is sufficient to assure adequate secondary side chemistry control during the outage.

The commitment contained in the original application specified an assessment that would be supplemental to the existing licensing basis chemistry monitoring requirements. Since the commitment does not satisfy the criteria for inclusion in Technical Specifications and since the primary and secondary water chemistry controls that are already specified in the licensing basis for the DBNPS provide adequate assurance of safety, FENOC does not believe escalation of the regulatory commitment into a license condition is necessary.

The commitment contained in the amendment application specified completion prior to operation beyond the original surveillance interval (i.e., March 9, 2004). This completion time was selected to assure that this action was performed prior to utilizing the surveillance interval extension requested in the amendment application. In order to assure the appropriate evaluation is performed in a timely manner following restart, FENOC revises its commitment to read:

Within 30 days following restart (i.e. entry into Mode 2) from the thirteenth refueling outage, the DBNPS staff will assure that the steam generator layup and storage conditions during the period between December 1, 2003, and restart from the thirteenth refueling outage were consistent with the conclusions of the assessment contained in Framatome-ANP Document 51-5033009-03.

Based on the above information, FENOC does not believe that escalation of this commitment into a license condition is necessary. However, if the NRC finds that such a license condition is required to support issuance of the proposed amendment, FENOC consents to the imposition of the commitment specified above as a license condition.

Question #3:

It was indicated that circumferential cracks at the tube ends in the upper tubesheet were accounted for in the cycle 14 operational assessment. Please clarify how these indications were accounted for. For example, was it assumed that indications similar in size to that observed during refueling outage 13 are present in a fraction of the tubes that were not inspected with a rotating probe during refueling outage 13 (and that these indications were postulated to grow at a specific length/depth growth rate)? Provide the technical basis for the methodology used in assessing these circumferential cracks. For example, if you assumed that the circumferential cracks that you detected in refueling outage 13 were developing for one or more cycles, discuss your technical basis for this assumption.

Response:

As previously discussed in a letter from FENOC to the NRC dated December 17, 2003, (DBNPS Serial Number 3013), the tube ends inspected in 13RFO were those that had never been inspected (57%) in this region with a rotating coil (15.8 EFPY). Postulated upper tube end circumferential cracks that may have been present in other tube ends that were not inspected with a rotating probe in 13RFO were assumed to leak at end-of-cycle (EOC) 14 at the maximum possible rate (0.0277 gpm/tube at outermost periphery) based on test data from the OTSG tube end cracking (TEC) alternate repair criteria (ARC) program. However, these tubes were inspected in either of the previous two outages; therefore the likelihood of a large number of significant indications in the uninspected population of tubes is not expected. A conservative estimate of 5 is projected at EOC 14, and the size of the indications is not relevant since the indications are not a structural issue due to their location at the tube end and the leakage is assessed based on tube radial location and not flaw length/depth. Therefore, the issue of leakage from uninspected, undetected cracks is insignificant and the assumed leakage at EOC 14 is conservative. Undetected circumferential cracks in the 57% population inspected tube ends would have a maximum depth of about 45%TW at a POD of 0.95, from the technique utilized at EOC 13. The projected EOC 14 maximum depth after 1.85 EFPY is about 74% TW, using the 95th percentile upper bound maximum depth growth rate. Therefore, inspected but undetected cracks are not projected to leak at steam line break (SLB) conditions at EOC 14.

Question #4:

An axial indication was detected in the expanded region of the tube (2A-Row 63 Tube 78). This indication had a maximum reported depth of 99% through-wall. In your assessment of cracking in the roll transition, you indicated that you conservatively assumed that this indication (and one other) was "roll transition" cracking. You concluded that you could observe 5 axial indications at the end of the next cycle and that none are projected to have any effect on tube integrity or leakage contribution at the end of cycle 14. Given that one of the indications was measured to be nearly through-wall in 2002 (in refueling outage 13), discuss why no leakage is postulated to occur at the end of cycle 14. In your response please address how you are assessing when the crack started to develop (i.e., Have you assumed that the crack was developing for more than one cycle? If so, discuss your basis?)

Response:

The axial crack in tube 2A-Row 63 Tube 78 was in the roll expanded region of the tube. Primary to secondary leakage from flaws in this region is limited by the rolled tube-to-tubesheet interface. Based on its location, the axial indication in tube 2A-Row 63 Tube 78 was neither a TEC, nor a classical roll transition crack. Based on current growth rate data, it was assumed that the axial crack in tube 2A-Row 63 Tube 78 grew over multiple cycles. Since 57% of the tubes were inspected during 13RFO, as a conservative measure for assessments, a similar crack was assumed to exist in another tube that was not inspected by rotating probe during 13RFO. For assessments, both tube 2A-Row 63 Tube 78, and an assumed similar uninspected, undetected crack, was counted in both categories, with leakage assigned from the maximum possible category. The projected SLB leak rate at EOC 14 from this assumed uninspected, undetected axial crack was assumed to be the maximum possible rate (0.0277 gpm/tube at outermost periphery) based on test data from the OTSG TEC ARC program.

Therefore, for 14RFO assessments, it was assumed for roll transition axial primary water stress corrosion cracking (PWSCC), where leakage is not limited by the rolled tube-to-tubesheet interface, the number of detected cracks at EOC 13 was conservatively taken as 2, even though no detected cracks exactly fit into this category. For the EOC14 projections, a total of 5 axial PWSCC indications were projected. One that was not detected from the uninspected population during RFO 13, which is assumed to leak as noted above, and 4 new indications. The projected EOC 14 95-95 SLB leak rate from a multi-cycle

Monte Carlo analysis of roll transition axial PWSCC, where inspection scope is explicitly considered in the model, is 0.0 gpm.

Question #5:

In several places, you indicate that indications are not significant and are not expected to challenge tube integrity (e.g., operational assessment ensures acceptable structural integrity during the extended surveillance interval). Please clarify the meaning of these statements. For example, do they indicate that for each degradation mechanism expected to occur (groove IGA, wear, volumetric IGA, axial and circumferential flaws at tube ends and dents, axial flaws at expansion transition, etc) that structural integrity will be maintained consistent with the margins in the design and licensing basis of the facility (since acceptable structural integrity could imply that no margins are being maintained)? In other words, do these statements imply that structural integrity involves demonstrating the tubes are capable of withstanding the loadings specified in the American Society of Mechanical Engineers (ASME) Code and Regulatory Guide 1.121, "Bases for Plugging Degraded Pressurized Water Reactor (PWR) Steam Generator Tubes?" Similarly for accident induced leakage integrity, you indicate that 1.0 gallon per minute is the appropriate limit. Is this limit consistent with your accident analyses which demonstrates that the dose consequences from this steam generator tube leakage are acceptable per General Design Criteria 19 of 10 CFR Part 50, Appendix A, and 10 CFR Part 100?

Response:

The statements that observed and projected degradation in the DBNPS OTSGs is not expected to challenge tube integrity means that adequate margins exist in meeting the condition monitoring and operational assessment requirements for EOC 13 and 14. As required by the DBNPS SG Management program, the margins used to assess tube integrity for condition monitoring and operational assessment evaluations are defined by NEI 97-06, "Steam Generator Program Guidelines," which includes margins as specified under Regulatory Guide 1.121. The limiting structural requirements, as verified by a recent Framatome review of OTSG structural integrity performance criteria (SIPC), consist of a factor of safety of 3 on normal operating differential pressure and a factor of safety of 1.0 on elastically calculated thermal mismatch MSLB axial loads. Bending loads from sources such as cross-flow and seismic conditions are not limiting at a factor of safety of 1.4.

The stated 1.0 gpm limit is consistent with the DBNPS design basis accident analyses which demonstrate that the dose consequences from postulated steam generator tube leakage are acceptable per General Design Criteria 19 of 10 CFR Part 50, Appendix A, and 10 CFR Part 100.

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
The DBNPS staff will assure that the steam generator layup and storage conditions during the period between December 1, 2003, and restart from the thirteenth refueling outage were consistent with the conclusions of the assessment contained in Framatome-ANP Document 51-5033009-03.	Within 30 days following restart (i.e. entry into Mode 2) from the thirteenth refueling outage.