September 5, 2003

Mr. John L. Skolds, Chairman
and Chief Executive Officer
AmerGen Energy Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: THREE MILE ISLAND NUCLEAR STATION, UNIT 1: REVIEW OF STEAM GENERATOR TUBE INSERVICE INSPECTION REPORT FOR FALL 2001 OUTAGE (TAC NO. MB6369)

Dear Mr. Skolds:

On March 5, 2002, AmerGen Energy Company, submitted the 2001 Steam Generator Tube Inservice Inspection Report for Three Mile Island Nuclear Station, Unit 1 (TMI-1), in accordance with the plant's Technical Specifications (TSs). This report described, in part, the TMI-1 steam generator inspection activities during the fall 2001 refueling outage (1R14). The U.S. Nuclear Regulatory Commission (NRC) staff's review of this submittal is documented in the enclosure. As discussed in the enclosure, the NRC staff concluded that you provided the information required by the TSs and that no additional follow-up is required at this time.

Sincerely,

/RA/

Donna M. Skay, Senior Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-289

Enclosure: As stated

cc w/encl: See next page

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ACCESSION NO.: ML032130034 *SE provided. No substantive changes.

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EVALUATION OF THREE MILE ISLAND NUCLEAR STATION, UNIT 1 2001 STEAM GENERATOR TUBE INSPECTION REPORT

On March 5, 2002, AmerGen Energy Company (AmerGen, the licensee), submitted the 2001 Steam Generator (SG) Tube Inservice Inspection Report for Three Mile Island Nuclear Station, Unit 1 (TMI-1), in accordance with the plant's Technical Specifications (TSs). This report described, in part, the licensee's SG inspection activities during the fall 2001 refueling outage (1R14). The Nuclear Regulatory Commission (NRC) staff reviewed Attachment 1 to Enclosure 1 of the March 5 submittal, Topical Report Number 151 (TR-151), "Report on the 2001 Outage 1R14 Eddy Current Examinations of the TMI-1 OTSG Tubing." On June 12, 2003, the staff participated in a conference call with the licensee to obtain clarification to a number of questions raised based on the staff's review of this report. The NRC staff's questions and a summary of AmerGen's responses are listed in Attachment 1 to this enclosure. The NRC staff's evaluation of AmerGen's report is below.

TMI-1 has two Babcock & Wilcox (B&W) designed once-through steam generators (OTSGs). These SGs have mill annealed Alloy 600 tubes. During refueling outage 1R14 in the fall of 2001, 100 percent of the inservice tubes in both SGs were inspected full length with a bobbin coil. At TMI-1, AmerGen defines "full length" from the kinetic expansion transition in the upper tubesheet to the roll expansion transition in the lower tubesheet.

In addition to the bobbin coil inspections, a rotating probe was used to inspect various locations in the SGs including: the upper tubesheet kinetic expansion transition region in approximately 39 percent of the tubes; approximately 33 percent of the tubes in the lower tubesheet kidney region, which included an axial length from 12 inches below the secondary face of the lower tubesheet to 4 inches above the secondary face of the lower tubesheet; the expanded region of inservice sleeves; plugs; and other special interest locations. Details of the inspection scope and results are documented in TR-151.

Inside Diameter (ID) Intergranular Attack (IGA)

The TMI-1 SGs contain ID IGA in both the unexpanded and expanded portion of the SG tubes. The ID IGA eddy current indications in the unexpanded portion of the SG tubing were dispositioned in accordance with the TMI-1 TS repair criteria which specifically addresses this degradation mechanism. AmerGen utilizes different repair criteria for the ID IGA found in the expanded portion of the SG tubing. The staff did not review in detail the information contained in TR-151 that related to ID IGA in the expanded portion of the tubing. Instead, the information related to degradation in this location will be utilized in the staff's assessment of the related repair criteria (submitted to the NRC by letter dated October 4, 2002), which is currently under NRC staff review. The following evaluation relates to the ID IGA identified in the unexpanded portion of the SG tubing.

The axial and circumferential extent of all ID IGA indications were measured. In addition, ID IGA indications with sufficient bobbin coil signal-to-noise ratio and bobbin voltage were also given a percent through-wall estimate. All ID IGA indications exceeding the TS repair limits (i.e., axial and circumferential extent and percent through-wall) were removed from service by plugging.

The axial and circumferential repair limits in the TSs were calculated based on a “no-growth” assumption (i.e., the ID IGA indications are not growing, and therefore, no allowance for growth was considered in the development of the TS repair limits). The licensee is required to perform two different statistical tests on three different eddy current parameters every outage to monitor the no-growth assumption. If all of these tests are passed, then the no-growth assumption is considered valid and can be applied in the operational assessment. If any of these tests are unsuccessful, a cycle-specific growth model must be developed and approved by the NRC to be used for the operational assessment.

In the submittal, the licensee stated that they performed the required statistical tests and that all parameters passed the test criteria, which supports the no-growth assumption. Details of the statistical tests are documented in Section III.B.1 of TR-151. The NRC staff reviewed the data and the summary of the statistical tests and results and concluded that the licensee appeared to follow the appropriate methodology related to the statistical procedures and had independently concluded that the no-growth assumption was valid for this operating cycle.

Severance of Plugged Tube B66-130

During the 1R14 SG inspection, the licensee identified a severed plugged tube which had caused wear damage on adjacent active tubes. The incident was documented in TMI-1’s Licensee Event Report 2001-03-00 as well as in NRC Information Notice 2002-02, titled “Recent Experience with Plugged Steam Generator Tubes,” dated January 8, 2002. Lastly, the NRC issued a letter to the licensee on September 12, 2002, with the staff’s evaluation of the information provided by the licensee. No new information was provided in TR-151 beyond that already made publicly available to the NRC.

Circumferential Flaws

The information in TR-151 indicated that during the inspection of the kinetic expansion region, 18 tubes were identified with circumferential indications, all of which were plugged. During the June 16, 2003, conference call, the licensee provided additional information related to these flaws (Question #6 in Attachment 1 to this enclosure). AmerGen believes they are ID IGA (i.e., associated with a previous thiosulphate intrusion) and further stated that they typically occur in locations of low residual stress (e.g., straight portion of tubing). Ten of these indications were identified during a previous outage and, although there was no apparent change to the flaw size or appearance, they were plugged. These indications were all located within the first ½ inch of expanded tubing in the upper tubesheet and were preventively plugged. The remaining eight indications were detected for the first time this outage, however, they were detected with a rotating probe and this outage was the first time these tubes were inspected with a rotating probe. The licensee indicated that at the completion of the 1R14 SG inspection, all kinetic expansions have now been examined with a rotating probe at least once.

The staff notes that there has been industry experience with the identification of ID circumferential flaws in the expanded region of the tube within the tubesheet. Therefore, the identification of circumferential flaws at TMI-1 in this region (not related to the thiosulphate intrusion) is a reasonable possibility. During future SG inspections, the licensee should carefully consider all available information for determining whether circumferential indications are new or are ID IGA and related to the thiosulphate intrusion. Collection of additional information, such as destructive examination results from a tube pull, may be beneficial in making this determination. This distinction is particularly important, because the flaw acceptance criteria for the kinetic expansion region assumes the flaws left in service are not growing. However, if the circumferential flaws were determined to be related to an active degradation mechanism, rather than an inactive degradation mechanism (such as the thiosulphate intrusion), this would invalidate the assumptions for applying the kinetic expansion acceptance criteria to these circumferential indications.

Conclusions

Based on review of the information provided in TR-151 as well as the information provided during the conference call, the NRC staff concludes that the licensee provided the information required by the TMI-1 TSs and that no additional follow-up is required at this time. However, the staff made an observation above, regarding circumferential indications, which the licensee may want to consider during future SG inspections.

THREE MILE ISLAND NUCLEAR STATION, UNIT 1 (TMI-1)
2001 STEAM GENERATOR (SG) TUBE INSPECTION REPORT
SUMMARY OF JUNE 12, 2003, CONFERENCE CALL

On June 12, 2003, the Nuclear Regulatory Commission (NRC) staff participated in a conference call with the licensee to discuss a number of questions raised by the staff during its review of this report. The questions that were provided to the licensee are shown in Attachment 2. The licensee's responses are summarized below.

1. The licensee indicated that all eddy current probes utilized for the inspection were qualified for use in TMI-1 SG tubing. Of the three tubes identified in the question, two tubes have dings in the lower tube end (believed to be caused by equipment used in the SG bowl) which prevented the passage of the 0.510-diameter bobbin probe. The third tube is believed to have a gradual diameter change in the tube within the tubesheet which prevented the passage of the 0.510-diameter bobbin probe. The exact cause of this change in diameter is not known. However, the licensee indicated that this is not a new issue, because eddy current history indicates that the 0.480-diameter bobbin probe has been used during previous outages. In addition, the licensee performed an inspection of the tube the entire length of the tubesheet with a rotating probe.

2. The licensee indicated that three of the crack-like indications were outside diameter (OD) intergranular attack (IGA), similar to other groove IGA that has been identified in the TMI-1 SGs during previous outages. One indication was an axial indication at the 12th tube support plate which was successfully in-situ pressure tested. The remaining crack-like indications were believed to be inside diameter (ID) IGA that was circumferential in nature (rather than the more typical volumetric configuration seen in the TMI-1 SGs). These indications were located in regions of the tubing without stress risers, and are further discussed in response to Question 6 (below).

3. The data in the first row in Table III-1 only identifies the number of tubes that contained ID IGA and that were inspected with the 0.540-diameter bobbin probe. The third paragraph on page 12 of the report identifies the total number of tubes with ID IGA (including those tubes with ID IGA that was only detected with a rotating probe). The rotating probe is believed to be capable of detecting smaller ID IGA flaws at TMI-1 than the bobbin probe. AmerGen concluded that the ID IGA which was only detected with a rotating probe was small.

   To respond to the second part of the question, the licensee indicated that during the 1R13 refueling outage (RO), all tubes with ID IGA that were detected in RO 1R12 were automatically inspected with a 0.540-diameter bobbin probe in RO 1R13. Therefore, all indications identified in RO 1R12 were included in the RO 1R13 population.

4. The licensee clarified that there were no indications recorded in the sleeves. There were no pressure boundary flaws in the plugs. Some plugs prevented the passage of a rotating probe, however, as discussed in response to Question 7 (below), the licensee indicated this was not caused by in-service degradation of the plug.

5. The licensee stated that all bobbin coil indications identified at tube-to-tube support plate (TSP) intersections were examined with a rotating probe. Based on the rotating probe inspections, any indications that occur away from the tube-to-TSP contact points are

automatically plugged. If the indication is located at a tube-to-TSP contact point, then the signal configuration is closely examined. The licensee stated that the eddy current signals from wear versus OD IGA are different in appearance and that there is some tube pull data from other once-through SGs to support this conclusion. Indications of OD IGA are plugged, and indications of wear are depth sized and left in-service if they do not exceed the technical specification plugging criteria. At TMI-1, there are approximately 400 wear indications at tube-to-TSP intersections left in-service which occur mainly at the 8^{th}, 9^{th} and 10^{th} TSP.

6. AmerGen clarified that there were 18 tubes plugged which contained ID circumferential indications. They are believed to all be ID IGA and typically occur in locations of low residual stress (e.g., straight portion of tubing). Ten of these indications were identified during a previous outage, and although there was no apparent change to the flaw size or appearance, they were plugged. These indications were all located within the first ½ inch of expanded tubing in the upper tubesheet and were preventively plugged. The remaining 8 indications were detected for the first time this outage, however, they were detected with a rotating probe and this outage was the first time these tubes were inspected with a rotating probe.

7. The NRC staff's question indicated that plugs were inspected with a bobbin probe. The licensee clarified that all plugs were inspected with a rotating probe. AmerGen indicated that all plugs are fabricated with Alloy 600 Thermally Treated material, and their pre-outage inspection plans included inspection of all plugs not previously inspected, as well as all plugs previously determined to be obstructed. The plug is designed such that the end of the plug contains notches that protrude above the tubesheet and thus are more susceptible to being dinged when equipment is in the area (e.g., 1980's SG tube repair activities). A total of 442 plugs were removed during the 1R14 outage (including 40 of the obstructed plugs) due to an unrelated issue and the licensee was able to conclude that plug collapse had not occurred in any of these. This further confirms the licensee's conclusion that the obstruction was only related to damage to the plug end that protrudes out of the tubesheet. Lastly, the results of the rotating probe inspections of the non-obstructed plugs (during the 1R14 and previous outage) did not identify any degradation of the plug.

8. This response to this question was incorporated in the discussion of Question 6.

THREE MILE ISLAND NUCLEAR STATION, UNIT 1
2001 STEAM GENERATOR TUBE INSPECTION REPORT
REQUEST FOR CLARIFICATIONS PROVIDED TO AMERGEN

Clarification is requested on the following issues:

1. The report stated that three tubes were inspected with a 0.480 diameter bobbin probe because the 0.510 diameter probe would not pass through the tubes. Describe what prevented the 0.510 diameter probe from passing through the tubes. Is the 0.480 diameter bobbin probe qualified for use (i.e., detection and/or sizing) in TMI SG tubing?

2. The report stated that all crack-like indications were removed from service that were identified in the freespan, expansion/transition region, the first 0.5 inches of the expanded region in 17 inch kinetic expansions, and the first 5 inches of the expanded region in 22 inch kinetic expansions. (Crack-like indications identified in the remainder of the kinetic expansion region were assessed and dispositioned based on the kinetic expansion repair criteria.) Were these indications circumferential, axial, ID initiated or OD initiated?

3. The first row in Table III-1 identifies the number of tubes that were examined with a 0.540 diameter bobbin probe due to: ID-initiated indications observed with bobbin coil probes during Outage 13R, and ID-initiated indications identified during Outage R14 with a 0.510 diameter bobbin probe. Why does this number of tubes vary more significantly than the number identified in the third paragraph on page 12 of the report? Why is the 0.540 diameter bobbin probe used only for those indications identified in 13R and not those that were identified in 12R as well?

4. Section III.B.1 states that Appendix II provides a listing of detected indications in tubes, sleeves and plugs that were in-service during Cycle 13. Identify the items in Appendix II that specifically identify detected indications in sleeves and plugs. Be prepared to discuss these indications and suspected cause of these indications.

5. Tube to tube support plate wear and OD Patch IGA have been identified in the TMI SGs. Given that these are both volumetric type of degradation modes, how does the licensee determine which degradation modes has been detected? This is of particular interest because the wear is being sized to determine whether it is required to be plugged and OD IGA is plugged on detection.

6. The licensee indicated that during the inspection of the kinetic expansion region, 13 tubes were identified with circumferential indications that were plugged. Were these previously detected? If not, is this an active degradation mechanism?

7. The report indicates that during the RPC inspection of the UTS Westinghouse rolled plugs, 42 plugs were determined to be obstructed at the plug end and would not pass a 0.460 diameter bobbin probe. Only 2 of these plugs remain in service.

   - Describe in more detail the suspected root cause of this obstruction.
   - Discuss whether these plugs were previously inspected and whether this concern existed at that time.

ATTACHMENT 2

- Thirty-three percent of these plugs were inspected with an RPC probe. Discuss the basis for not expanding the scope of inspection to the remaining 67% of the plugs.
- The licensee indicated that they believe the plug damage was caused by 1980's tube repair activities. They further indicated that they believed the plug damage was minor in nature. Discuss the basis for this conclusion.
- What is the basis for concluding that the remainder of the plug (i.e., beyond the plug end) isn't damaged.

8. Two of the circumferential indications previously discussed were located in the non-expanded portion of the SG tube within the tubesheet. Discuss the driving mechanism for this degradation.