AmerGen

An Exelon Company
AmerGen Energy Company, LLC
4300 Winfield Road
Warrenville, IL 60555

www.exeloncorp.com

Exelon.
Nuclear

Exelon Generation
4300 Winfield Road
Warrenville, IL 60555

10 CFR 50.54 (f)

RS-04-159
5928-04-20237

October 29, 2004

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
11555 Rockville Pike
Rockville, Maryland 20852

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Three Mile Island Nuclear Station, Unit No. 1
Facility Operating License No. DPR-50
NRC Docket No. 50-289

Subject: Response to NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections"

Reference: NRC Generic Letter 2004-01, "Requirements for Steam Generator Tube Inspections," dated August 30, 2004

The purpose of this letter is to provide the Exelon Generation Company, LLC (EGC) and the AmerGen Energy Company, LLC (AmerGen) sixty-day response to the referenced NRC Generic Letter. The responses to NRC Generic Letter 2004-01 questions are provided in the attachments to this letter.

Because of the similarities in steam generator design, operation, and inspection history, the responses for Braidwood Station, Unit 1 and Byron Station, Unit 1 are combined and provided in Attachment 1. The Braidwood Station, Unit 2 and Byron Station, Unit 2, steam generators, also similar in design, operation, and inspection history, have their combined responses provided in Attachment 2. The Three Mile Island Nuclear Station, Unit 1 response is provided in Attachment 3.

As demonstrated in the attached responses, EGC and AmerGen conclude that the steam generator tube inspections performed at Braidwood Station Units 1 and 2; Byron Station Units 1 and 2; and Three Mile Island Nuclear Station, Unit 1 are in full compliance with their respective technical specifications and 10 CFR 50, Appendix B requirements.

Should you have any questions concerning this letter, please contact David J. Chrzanowski at (630) 657-2816.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 10/29/04

Keith R. Jury

Keith R. Jury
Director – Licensing and Regulatory Affairs
Exelon Generation Company, LLC
AmerGen Energy Company, LLC

Attachments: Attachment 1, Response to NRC Generic Letter 2004-01, Braidwood Station, Unit 1 and Byron Station, Unit 1
Attachment 2, Response to NRC Generic Letter 2004-01, Braidwood Station, Unit 2 and Byron Station, Unit 2
Attachment 3, Response to NRC Generic Letter 2004-01, Three Mile Island Nuclear Station, Unit 1

cc: Regional Administrator – NRC Region I
Regional Administrator – NRC Region III

Attachment 1
Response to NRC Generic Letter 2004-01
Braidwood Station, Unit 1 and Byron Station, Unit 1

Requested Information 1

Addressees should provide a description of the SG tube inspections performed at their plant during the last inspection. In addition, if they are not using SG tube inspection methods whose capabilities are consistent with the NRC's position, addressees should provide an assessment of how the tube inspections performed at their plant meet the inspection requirements of the TS in conjunction with Criteria IX and XI of 10 CFR Part 50, Appendix B, and corrective action taken in accordance with Appendix B, Criterion XVI. This assessment should also address whether the tube inspection practices are capable of detecting flaws of any type that may potentially be present along the length of the tube required to be inspected and that may exceed the applicable tube repair criteria.

Response:

Steam generator tube inspections performed at Braidwood Station, Unit 1 and Byron Station, Unit 1 are consistent with the NRC's position regarding tube inspections.

Background

Braidwood Station, Unit 1 and Byron Station, Unit 1 each contain four Babcock & Wilcox feedring replacement steam generators (RSGs). Each steam generator contains 6633 thermally treated Inconel-690 U-tubes that have an outer diameter of 0.6875-inches with a wall thickness of 0.040-inches. Stainless steel lattice grids and fan bars support the tubing in the straight legs and U-bends. The tubing within the tubesheet is hydraulically expanded throughout the full thickness of the tubesheet. The low row U-bend region, up to Row 21, received additional thermal stress relief following tube bending. The U-bends are designed to maximize the bend radius in rows 1 through 3 to eliminate the tight radius condition. The units operate on approximately 18-month fuel cycles.

The Braidwood Station, Unit 1 RSGs were installed in November of 1998 and had operated 5.64 effective full power years (EFPY) at the time of their last inspection in October 2004, which was the unit's eleventh refueling outage. The Byron Station, Unit 1 RSGs were installed in March of 1998 and had operated 3.79 EFPY at the time of their last inspection in March 2002, which was the unit's eleventh refueling outage.

Braidwood Station, Unit 1 Previous Inspection Information

The most recent Braidwood Station, Unit 1 RSG tube inspection was performed in the October 2004 refueling outage. The RSG inspection scope was governed by: Braidwood Station Technical Specification (TS) 5.5.9, "Steam Generator (SG) Tube Surveillance Program," the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) SG Examination Guidelines; regulatory documents and commitments; Exelon ER-AP-420 procedure series (Steam Generator Management Program Activities); and the results of a Braidwood Station, Unit 1 specific degradation assessment. The inspection techniques and equipment were capable of reliably detecting the specific degradation mechanisms applicable to the Braidwood Station, Unit 1 RSGs. The inspection techniques, essential variables and equipment were qualified to Appendix H, "Performance Demonstration for Eddy Current Examinations," of the EPRI PWR SG Examination Guidelines.

The Braidwood Station, Unit 1 October 2004, eleventh refueling outage, RSG eddy current inspection base scope included:

- 100% Full-length bobbin coil inspection of tubes in RSG 1B
- Full-length bobbin coil inspection of tubes identified in the RSG 1B to be in tube to tube contact based on previous inspection results (36 tubes)
- 25% +Point™ probe inspection of hot leg dents and dings > 5.0 volts in bobbin coil signal strength in the RSG 1B (no tubes met this criterion)
- +Point™ probe inspection of all bobbin coil non-quantifiable indications (i.e., "I-codes")

Byron Station, Unit 1 Previous Inspection Information

The most recent Byron Station, Unit 1 RSG tube inspection was performed in the March 2002 refueling outage. The RSG inspection scope was governed by: Byron Station TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program;" the EPRI PWR SG Examination Guidelines; regulatory documents and commitments; Exelon ER-AP-420 procedure series; and the results of a Byron Station, Unit 1 specific degradation assessment. The inspection techniques and equipment were capable of reliably detecting the specific degradation mechanisms applicable to the Byron Station, Unit 1 RSGs. The inspection techniques, essential variables and equipment were qualified to Appendix H of the EPRI PWR SG Examination Guidelines.

The Byron Station, Unit 1 March 2002, eleventh refueling outage, RSG eddy current inspection scope included:

- 100% Full-length Bobbin coil inspection of peripheral tubes in all RSGs (excluding the tubes located underneath the manipulator base plate)
- 50% Full-length Bobbin coil inspection of interior tubes in all RSGs
- Full-length Bobbin coil inspection of tubes identified to be in tube to tube contact based on previous inspection results (7 tubes)
- 25% +Point™ probe of hot leg top of tubesheet region $\pm$ 3 inches in all RSGs
- 25% +Point™ probe of hot leg dents and dings > 5.0 volts in bobbin coil signal strength (no tubes met this criterion)
- +Point™ probe inspection of all bobbin coil non-quantifiable indications (i.e.,"I-codes")

Inspection Techniques

Damage Mechanism	Inspection Method	EPRI ETSS*
Fan bar wear	Bobbin	96004.3
Lattice grid wear	Bobbin	96004.3
Foreign object wear	Bobbin +Point™ +Point™	96004.3 21998.1 96910.1

Damage Mechanism	Inspection Method	EPRI ETSS*
Tube to tube contact wear	Bobbin	96004.3
Stress corrosion cracking (SCC) at dents	+Point™	96703.1
SCC at hot leg top of tubesheet expansion (Byron Unit 1 only)	+Point™	20409.1 20511.1 20510.1

* ETSS (Examination Technique Specification Sheet)

Prior to use, the above inspection techniques were site qualified, or for instances where site specific damage mechanism signals were not available, the techniques were shown to be equivalent to the EPRI industry qualified techniques, in accordance with the requirements of the EPRI PWR SG Guidelines Appendix H. Use of these inspection techniques provides an adequate assurance that potential flaws that may have been present were identified and assessed against the applicable repair criteria.

The eddy current nondestructive testing examinations were performed by personnel qualified to the American Society of Mechanical Engineers (ASME) Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components,"1989 Edition, SNT TC-1A, "Standard for Qualification and Certification of Nondestructive Testing Personnel," 1984 Edition and to the requirements of EPRI PWR SG Examination Guidelines Appendix G, "Qualification of Nondestructive Examination Personnel for the Analysis of Nondestructive Examination Data," (current revision). The nondestructive examination procedures and equipment used to perform the eddy current inspections met the requirements of the ASME Code Sections XI and V, "Nondestructive Examination," 1989 Edition, as well as the requirements of the EPRI PWR SG Examination Guidelines (current revision). Exelon procedures were in place to verify and ensure that all personnel, equipment and inspection processes were qualified to appropriate requirements and that the examination results were reviewed and documented to assure that the test requirements were satisfied.

As previously discussed, Braidwood Station, Unit 1 and Byron Station, Unit 1, performed an assessment to determine the types of degradation that potentially could occur along the full length of a tube, to ensure that appropriate inspection techniques were applied to detect potential degradation that may have been present, and to ensure that tube repairs were performed to maintain the integrity of the RSG. These measures ensured that the requirements of Braidwood Station, Unit 1 and Byron Station, Unit 1 TS and 10 CFR 50, Appendix B Criteria IX, "Control of Special Processes," XI, "Test Control," and XVI, "Corrective Action," were satisfied.

Requested Information 2

If addressees conclude that full compliance with the TS in conjunction with Criteria IX, XI and XVI of 10 CFR Part 50, Appendix B, requires corrective actions, they should discuss *their proposed corrective actions (e.g., changing inspection practices consistent with the NRC's position or submitting a TS amendment request with the associated safety basis for limiting the inspections) to achieve full compliance. If addressees choose to change their TS, the staff has included in the Attachment suggested changes to the TS definitions for a tube inspection and for plugging limits to show what may be acceptable to the staff in cases where the tubes are expanded for the full depth of the tubesheet and where the extent of the inspection in the tubesheet region is limited.*

Response:

As stated in response to Requested Information 1, for Braidwood Station, Unit 1 and Byron Station, Unit 1, all areas of potential damage mechanisms, as determined by the unit and outage specific degradation assessments, were inspected using qualified inspection techniques. Therefore Braidwood Station, Unit 1 and Byron Station, Unit 1 are in full compliance with their TS in conjunction with 10 CFR 50, Appendix B Criteria.

Requested Information 3

For plants where SG tube inspections have not been or are not being performed consistent with the NRC's position on the requirements in the TS in conjunction with Criteria IX, XI, and XVI of 10 CFR Part 50, Appendix B, the licensee should submit a safety assessment (i.e., a justification for continued operation based on maintaining tube structural and leakage integrity) that addresses any differences between the licensee's inspection practices and those called for by the NRC's position. Safety assessments should be submitted for all areas of the tube required to be inspected by the TS, where flaws have the potential to exist and inspection techniques capable of detecting these flaws are not being used, and should include the basis for not employing such inspection techniques. The assessment should include an evaluation of (1) whether the inspection practices rely on an acceptance standard (e.g., cracks located at least a minimum distance of x below the top of the tube sheet, even if these cracks cause complete severance of the tube) which is different from the TS acceptance standards (i.e., the tube plugging limits or repair criteria), and (2) whether the safety assessment constitutes a change to the "method of evaluation" (as defined in 10 CFR 50.59) for establishing the structural and leakage integrity of the joint. If the safety assessment constitutes a change to the method of evaluation under 10 CFR 50.59, the licensee should determine whether a license amendment is necessary pursuant to that regulation.

Response:

Not applicable based on response to Requested Information 2 above.

Attachment 2
Response to NRC Generic Letter 2004-01
Braidwood Station, Unit 2 and Byron Station, Unit 2

Requested Information 1

Addressees should provide a description of the SG tube inspections performed at their plant during the last inspection. In addition, if they are not using SG tube inspection methods whose capabilities are consistent with the NRC's position, addressees should provide an assessment of how the tube inspections performed at their plant meet the inspection requirements of the TS in conjunction with Criteria IX and XI of 10 CFR Part 50, Appendix B, and corrective action taken in accordance with Appendix B, Criterion XVI. This assessment should also address whether the tube inspection practices are capable of detecting flaws of any type that may potentially be present along the length of the tube required to be inspected and that may exceed the applicable tube repair criteria.

Response:

Steam generator tube inspections performed at Braidwood Station, Unit 2 and Byron Station, Unit 2 are consistent with the NRC's position regarding tube inspections.

Background

Braidwood Station, Unit 2 and Byron Station, Unit 2 each contain four Westinghouse Model D-5 recirculating, pre-heater type steam generators (SGs). Each SG contains 4,570 thermally treated Alloy-600, U-tubes that have an outer diameter of 0.750 inch with a 0.043 inch nominal wall thickness. The support plates are 1.125 inch thick stainless steel (ASME SA 240 Type 405) and have quatrefoil broached holes. The tubing within the tubesheet is hydraulically expanded throughout the full thickness of the tubesheet. The low row U-bend region, up through row 9, received additional thermal stress relief following tube bending. The units operate on approximately 18-month fuel cycles.

The Braidwood Station, Unit 2 SGs had operated 12.79 Effective Full Power Years (EFPY) at the time of their last inspection in November 2003, which was the tenth refueling outage for the unit. The Byron Station, Unit 2 SGs had operated 14.23 EFPY at the time of their last inspection in March of 2004, which was the eleventh refueling outage for the unit.

Braidwood Station, Unit 2 Previous Inspection Information

The most recent Braidwood Station, Unit 2 SG tube inspection was performed in the November 2003 refueling outage. The SG inspection scope was governed by: Braidwood Station Technical Specification (TS) 5.5.9, "Steam Generator (SG) Tube Surveillance Program," the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) SG Examination Guidelines; regulatory documents and commitments; Exelon ER-AP-420 procedure series (Steam Generator Management Program Activities); and the results of a Braidwood Station, Unit 2 degradation assessment. The inspection techniques and equipment were capable of reliably detecting the specific degradation mechanisms applicable to the Braidwood Station, Unit 2 SGs. The inspection techniques, essential variables and equipment were qualified to Appendix H, "Performance Demonstration for Eddy Current Examination," of the EPRI PWR SG Examination Guidelines.

The Braidwood Station, Unit 2 November 2003, tenth refueling outage, steam generator eddy current inspection scope included:

- 100% full-length Bobbin coil inspection of tubes in all four SGs
- 50% +Point™ probe inspection of hot leg top of tubesheet (+/- 3 inches) in all four SGs
- 50% +Point™ probe inspection of row 1 and row 2 U-bend region in all four SGs
- 50% +Point™ probe inspection of hot leg dents and dings >5.0 volts in bobbin coil signal strength in all four SGs
- 25% +Point™ probe inspection of pre-heater baffle expansions in two SGs
- 44% (34 tubes of 77) +Point™ probe inspection of hot leg top of tubesheet (+/- 3 inches) in tubes with potentially high residual stress
- +Point™ probe inspection of all bobbin coil non-quantifiable indications (i.e., "I-codes")

Byron Station, Unit 2 Previous Inspection Information

The most recent Byron Station, Unit 2 SG tube inspection was performed in the March 2004 refueling outage. The SG inspection scope was governed by: Byron TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program"; the EPRI PWR SG Examination Guidelines; regulatory documents and commitments; Exelon ER-AP-420 procedure series; and the results of a Byron Station, Unit 2 degradation assessment. The inspection techniques and equipment were capable of reliably detecting the specific degradation mechanisms applicable to the Byron Station, Unit 2 SGs. The inspection techniques, essential variables and equipment were qualified to Appendix H of the EPRI PWR SG Examination Guidelines.

The Byron Station, Unit 2 March 2004, eleventh refueling outage, steam generator eddy current inspection scope included:

- 100% full-length Bobbin coil inspection of tubes in all four SGs
- 25% +Point™ probe inspection of hot leg top of tubesheet (+/- 3 inches) in all four SGs
- 25% +Point™ probe inspection of row 1 and row 2 U-bend region in all four SGs
- 25% +Point™ probe inspection of hot leg dents and dings >5.0 volts in bobbin coil signal strength in all four SGs
- 25% +Point™ probe inspection of pre-heater baffle expansions in two SGs
- 100% +Point™ probe inspection of hot leg top of tubesheet (+/- 3 inches) in tubes with potentially high residual stress (40 tubes)
- +Point™ probe inspection of all bobbin coil non-quantifiable indications (i.e., "I-codes")

Inspection Techniques

Damage Mechanism	Inspection Method	EPRI ETSS*
Anti-vibration bar (AVB) bar wear	Bobbin	96004.3
Pre-heater/Tube support plate (TSP) wear	Bobbin	96004.3
Foreign object wear	Bobbin +Point™ +Point™	96004.3 21998.1 96910.1
Intergranular attack (IGA)/SCC at hot leg top of tubesheet (TTS)	+Point™	21409.1 20511.1 20510.1 21410.1
IGA/SCC at TSPs	Bobbin	96007.1
SCC low row U-bends	+Point™	96511.1
SCC at dents and dings	+Point™	96703.1
SCC at pre-heater baffle plate Expansions	Bobbin	21410.1 20511.1 20510.1
Freespan pitting, volumetric Indications	Bobbin	96005.2

* ETSS (Examination Technique Specification Sheet)

Prior to use, the above inspection techniques were site-specific qualified, or for instances where site-specific damage mechanism signals were not available, the techniques were shown to be equivalent to the EPRI industry qualified techniques, in accordance with the requirements of the EPRI PWR SG Guidelines Appendix H. Use of these inspection techniques provided an adequate assurance that potential flaws that may have been present were identified and assessed against the applicable repair criteria.

The eddy current nondestructive testing examinations were performed by personnel qualified to the ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," 1989 Edition, SNT TC-1A, "Standard for Qualification and Certification of Nondestructive Testing Personnel," 1984 Edition and to the requirements of the EPRI PWR SG Examination Guidelines Appendix G, "Qualification of Nondestructive Examination Personnel for Analysis of Nondestructive Examination Data," (current revision). The nondestructive examination procedures and equipment used to perform the eddy current inspections met the requirements of the ASME Code Sections XI and V, "Nondestructive Examination," 1989 Edition, as well as the requirements of the EPRI PWR SG Examination Guidelines (current revision). Exelon procedures were in-place to verify and ensure that all personnel, equipment and inspection processes were qualified to appropriate requirements and that the examination results were reviewed and documented to assure that the test requirements were satisfied.

As previously discussed, Braidwood Station, Unit 2 and Byron Station, Unit 2, performed an assessment to determine the types of degradation that potentially could occur along the full length of a tube, to ensure that appropriate inspection techniques were applied to detect potential degradation that may have been present, and to ensure that tube repairs were performed to maintain the integrity of the SG. These measures ensured that the requirements of Braidwood Station, Unit 2 and Byron Station, Unit 2 TS and 10 CFR Part 50, Appendix B Criteria IX, "Control of Special Processes," XI, "Test Control," and XVI, "Corrective Action," were satisfied.

Requested Information 2

If addressees conclude that full compliance with the TS in conjunction with Criteria IX, XI and XVI of 10 CFR Part 50, Appendix B, requires corrective actions, they should discuss their proposed corrective actions (e.g., changing inspection practices consistent with the NRC's position or submitting a TS amendment request with the associated safety basis for limiting the inspections) to achieve full compliance. If addressees choose to change their TS, the staff has included in the Attachment suggested changes to the TS definitions for a tube inspection and for plugging limits to show what may be acceptable to the staff in cases where the tubes are expanded for the full depth of the tubesheet and where the extent of the inspection in the tubesheet region is limited.

Response:

As stated in response to Requested Information 1, for Braidwood Station, Unit 2 and Byron Station, Unit 2, all areas of potential and non-active damage mechanisms, as determined by the unit and outage specific degradation assessments, were inspected using qualified inspection techniques. Therefore Braidwood Station, Unit 2 and Byron Station, Unit 2 are in full compliance with the TS in conjunction with 10 CFR 50, Appendix B Criteria.

Requested Information 3

For plants where SG tube inspections have not been or are not being performed consistent with the NRC's position on the requirements in the TS in conjunction with Criteria IX, XI, and XVI of 10 CFR Part 50, Appendix B, the licensee should submit a safety assessment (i.e., a justification for continued operation based on maintaining tube structural and leakage integrity) that addresses any differences between the licensee's inspection practices and those called for by the NRC's position. Safety assessments should be submitted for all areas of the tube required to be inspected by the TS, where flaws have the potential to exist and inspection techniques capable of detecting these flaws are not being used, and should include the basis for not employing such inspection techniques. The assessment should include an evaluation of (1) whether the inspection practices rely on an acceptance standard (e.g., cracks located at least a minimum distance of x below the top of the tube sheet, even if these cracks cause complete severance of the tube) which is different from the TS acceptance standards (i.e., the *tube plugging limits or repair criteria), and (2) whether the safety assessment constitutes a change to the "method of evaluation" (as defined in 10 CFR 50.59) for establishing the structural and leakage integrity of the joint. If the safety assessment constitutes a change to the method of evaluation under 10 CFR 50.59, the licensee should determine whether a license amendment is necessary pursuant to that regulation.*

Response:

Not applicable based on response to Requested Information 2 above.

Attachment 3
Response to NRC Generic Letter 2004-01
Three Mile Island Nuclear Station, Unit No.1

Requested Information 1

Addressees should provide a description of the SG tube inspections performed at their plant during the last inspection. In addition, if they are not using SG tube inspection methods whose capabilities are consistent with the NRC's position, addressees should provide an assessment of how the tube inspections performed at their plant meet the inspection requirements of the TS in conjunction with Criteria IX and XI of 10 CFR Part 50, Appendix B, and corrective action taken in accordance with Appendix B, Criterion XVI. This assessment should also address whether the tube inspection practices are capable of detecting flaws of any type that may potentially be present along the length of the tube required to be inspected and that may exceed the applicable tube repair criteria.

Response:

<u>Background</u>

TMI-1 has two Babcock & Wilcox (B&W) designed 177FA once through steam generators (OTSGs). Each OTSG contains 15,531 sensitized Inconel-600 (I-600) tubes that have an outer diameter of 0.625 inch with a nominal wall thickness of 0.037 inch. Each tube is supported by 15 tube support plates (TSPs) that are 1.5-inches thick carbon steel and have trefoil broached holes, except for the 15th TSP, which has 1,626 drilled holes for the tubes at the outer periphery of the tube bundles. The lower tube ends are roll-expanded to a minimum depth of 1.0 inch from the primary face of the tubesheet and a fillet weld exists between the primary face of the tubesheet and the tube end. All of the in-service tubing within the upper tubesheet is kinetically expanded to a depth of 17 inches or 22 inches from the primary face of the tubesheet.

The unit operates on approximately a 24-month fuel cycle.

The TMI-1 steam generators had operated for 19.23 effective full power years at the time of their last inspection in the Fall 2003, which was the unit's 14th refueling outage.

<u>Previous Inspection Information</u>

The TMI-1 Fall 2003 refueling outage steam generator tube eddy current inspection is summarized in Table 1. In addition to the technical specification (TS) inspection requirements, the degradation assessment evaluated the EPRI PWR SG Examination Guidelines in effect at the time of the inspection and available industry data for steam generators of similar design to determine possible damage mechanisms that may exist in the steam generators. Once the possible damage mechanisms were identified, qualified inspection techniques were used to inspect for the damage mechanisms in the respective areas.

As previously discussed, TMI-1 an assessment was performed to determine the types of degradation that potentially could occur along the length of a tube, ensure that appropriate inspection techniques were applied to detect possible degradation that may have been present, and to ensure that tube repairs were performed to maintain the integrity of the OTSGs. These measures ensured that the requirements of the plant's

TS, 10 CFR 50, Appendix B Criteria IX, "Control of Special Processes," XI, "Test Control," and XVI, "Corrective Action," were satisfied.

Conclusion:

Based on the information provided in Table 1 and the discussion above, the TMI-1 OTSG tube inspection approach/methods are consistent with the NRC's position as provided in Generic Letter 2004-01.

Table 1

Item	Steam Generator Region	Inspection Probe	Inspection Scope and Extent
1	Full Length of Tube (Note 1)	Bobbin	100% - Full Length
2	Dents ≥2.5 Volts (Note 2)	+Point™	100% of recorded dents located above the lower tubesheet secondary face.
3	Dents ≥2.5 Volts Located Within the Lower Tubesheet Kidney Region Examination Defined Area (Note 6)	+Point™	Approximately 33% of the recorded dents are examined as part of the defined kidney examination region.
4	Dents ≥2.5 Volts Located at the Lower Tubesheet Secondary Face (LTSF) or Below That are Not Included in the Lower Tubesheet Kidney Region Examination Scope	+Point™	Approximately 33% of the recorded dents are examined.
5	Sludge Pile / Lower Tube Sheet Crevice / Kidney Region [LTSF +5" to -4"]	+Point™	33% of the defined kidney region (sludge pile/dented tube region of the lower tubesheet).
6	Lower Tube Ends, Lower Rolls, and Lower Roll Transitions (Note 3)	+Point™ and 0.080" High Frequency Pancake for Length Sizing Inside Diameter Intergranular Attack (ID IGA)	100% of the expansions in OTSG-B and approximately 59% of the in service expansions in OTSG-A. The examinations in OTSG-A were limited to a large peripheral region critical area and buffer zone. No degradation was detected in the OTSG-A buffer zone.
7	Upper TubeSheet (UTS) Kinetic Expansions and Transitions (See Note 4)	+Point™ and 0.080" High Frequency Pancake for Length Sizing ID IGA	Approximately 33% of the in service tubes.

Item	Steam Generator Region	Inspection Probe	Inspection Scope and Extent
8	Lane and Wedge Tubes Bordering the Sleeved Tubes – 15th Tube Support Plate (TSP) and Upper Tubesheet Face	+Point™ and 0.080" High Frequency Pancake for Length Sizing ID IGA	100% of the in service non-sleeved tubes at the upper tubesheet secondary face and the 15th TSP.
9	Upper Tubesheet	+Point™ and 0.080" High Frequency Pancake for Length Sizing ID IGA	Recorded bobbin coil indications and previous degraded tube ID IGA indications.
10	Bobbin Indications (Note 5)	+Point™ and 0.080" High Frequency Pancake for Length Sizing ID IGA	Previous degraded tube ID IGA indications, and 100% of the indications as defined in Note 5 below.
11	Alloy 690 Sleeves – Unexpanded Region	Bobbin	Approximately 33% of the in service sleeves.
12	Alloy 690 Sleeves – Upper Roll Expansions	+Point™	Approximately 33% of the in service sleeves.
13	Alloy 690 Sleeves – Lower Roll Expansion and Approximately 3" of Parent Tube Below the Lower Sleeve End	+Point™	100% of the in service sleeves.

Notes for Table 1:

1. Full-length of the tube is defined as the length of unexpanded tubing from the lower tube end expansion transition to the upper tube end kinetic expansion transition.
2. TMI-1 does not use the "ding" nomenclature; all indications of mechanical tube deformation are called "dents."
3. +Point™ inspection to approximately 1" beyond inboard roll transition is required.
4. Examination scope and dispositioning criteria were submitted to the NRC for review prior to the Fall 2003 outage [See AmerGen Energy Company, LLC letter to NRC, dated October 4, 2002 (5928-02-20194), "Additional Information Regarding Kinetic Expansion Inspection and Repair Criteria." and AmerGen Energy Company, LLC letter to NRC, dated August 16, 2002 (5928-04-20141), "Additional Information Regarding Kinetic Expansion Inspection and Repair Criteria."]
5. +Point™ probe inspection was performed on bobbin coil indications of possible degradation, TSP wear indications that exhibited change, all recorded permeability variation indications, and all recorded pilgering indications.

   Wear indications on bobbin coil inspection that were confirmed as TSP wear with +Point™ during a prior outage and did not exhibit change were not examined with the +Point™ probe during the Fall 2003 outage. Bobbin coil change is defined as a difference of >10 degrees or >0.5 volts for the same location from prior examination data. These wear indications were depth sized and dispositioned using the qualified bobbin coil depth sizing results.

6. The "kidney region" has been defined to generally include areas on the lower tubesheet array that bound lower tubesheet secondary face dents and the highest sludge heights. Examination results at other OTSG plants have indicated that the bobbin coil detection capability may be reduced in this region. (To date there is no evidence that the bobbin probe Probability of Detection (POD) is reduced in this tubing region at TMI-1.)

Requested Information 2

If addressees conclude that full compliance with the TS in conjunction with Criteria IX, XI and XVI of 10 CFR Part 50, Appendix B, requires corrective actions, they should discuss their proposed corrective actions (e.g., changing inspection practices consistent with the NRC's position or submitting a TS amendment request with the associated safety basis for limiting the inspections) to achieve full compliance. If addressees choose to change their TS, the staff has included in the Attachment suggested changes to the TS definitions for a tube inspection and for plugging limits to show what may be acceptable to the staff in cases where the tubes are expanded for the full depth of the tubesheet and where the extent of the inspection in the tubesheet region is limited.

Response:

As stated in response to question 1, all areas of potential and non-active damage mechanisms, as determined by the unit and outage specific degradation assessment, were inspected using qualified inspection techniques. Therefore, TMI-1 is in full compliance with its TS in conjunction with 10 CFR 50, Appendix B Criteria.

Requested Information 3

For plants where SG tube inspections have not been or are not being performed consistent with the NRC's position on the requirements in the TS in conjunction with Criteria IX, XI, and XVI of 10 CFR Part 50, Appendix B, the licensee should submit a safety assessment (i.e., a justification for continued operation based on maintaining tube structural and leakage integrity) that addresses any differences between the licensee's inspection practices and those called for by the NRC's position. Safety assessments should be submitted for all areas of the tube required to be inspected by the TS, where flaws have the potential to exist and inspection techniques capable of detecting these flaws are not being used, and should include the basis for not employing such inspection techniques. The assessment should include an evaluation of (1) whether the inspection practices rely on an acceptance standard (e.g., cracks located at least a minimum distance of x below the top of the tube sheet, even if these cracks cause complete severance of the tube) which is different from the TS acceptance standards (i.e., the tube plugging limits or repair criteria), and (2) whether the safety assessment constitutes a change to the "method of evaluation" (as defined in 10 CFR 50.59) for establishing the structural and leakage integrity of the joint. If the safety assessment constitutes a change to the method of evaluation under 10 CFR 50.59, the licensee should determine whether a license amendment is necessary pursuant to that regulation.

Response:

Not applicable based on response to question 2 above.