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

Three Mile Island, Unit 1 (TMI Unit 1)
Facility Operating License No. DPR-50
NRC Docket No. 50-289

Subject: Response To Request For Additional Information – Technical Specification Change Request No. 331: Application for Technical Specification Improvement Regarding Steam Generator Tube Integrity (TAC No. MD1807)

References:

1) USNRC Letter dated November 9, 2006, "Request for Additional Information Regarding the Steam Generator Tube Integrity Technical Specification Amendment (TAC No. MD1807)"

2) USNRC Letter dated August 14, 2006, "Three Mile Island, Unit 1 – Request for Additional Information Regarding the Steam Generator Tube Integrity Technical Specification Amendment (TAC No. MD1807)"

3) AmerGen Energy Company, LLC letter to NRC dated May 15, 2006 (5928-06-20390), "Technical Specification Change Request No. 331 – Application for Technical Specification Improvement Regarding Steam Generator Tube Integrity"

4) AmerGen Energy Company, LLC letter to NRC dated October 6, 2006 (5928-06-20492), "Response To Request For Additional Information – Technical Specification Change Request No. 331: Application for Technical Specification Improvement Regarding Steam Generator Tube Integrity (TAC No. MD1807)"

This letter provides additional information in response to: (1) NRC request for additional information (RAI), dated November 9, 2006 regarding sleeve repairs (Reference 1), and (2) NRC RAI questions regarding sleeve repairs contained in Reference 2, regarding TMI Unit 1 Technical Specification Change Request No. 331, submitted to NRC for review on May 15, 2006 (Reference 3). The additional information is provided in Enclosure 1.

As described in the Enclosure 1 responses, the proposed Technical Specification page 6-26 Insert markup has been revised from our submittal of October 6, 2006 (Reference 4) to incorporate additional requirements and clarifications regarding sleeve repairs, consistent with the NRC approved TSTF-449, Revision 1.

Additionally, the previously proposed markups for Technical Specification page 4-8 and the associated Bases page 4-2b Insert markup are revised from our submittal of October 6, 2006 (Reference 4) to clarify that primary-to-secondary leakage surveillance is not required until 12 hours after establishment of Power Operation, which ensures sufficient xenon buildup in the reactor coolant system to support accurate leakage measurement. The previous proposed markup inadvertently required primary-to-secondary leak rate quantification at all plant operating modes. The revised TS markups are consistent with the intent of the TSTF-449, Revision 4, which only requires primary-to-secondary leak rate quantification when stable power operation is achieved.

The previously proposed markup for TS Bases page 3-15a is also revised to delete the statement describing the contribution of the primary-to-secondary leak rate to 10 CFR Part 100 dose limits. This contribution has been adequately described in the additional Bases paragraphs being incorporated into TS page 3-15a, as previously proposed, and the TS 4.19 Bases (Applicable Safety Analyses) previously proposed, both of which are fully consistent with the TSTF-449, Revision 4 Bases.

These changes have no impact on the conclusions of the original safety analysis or no significant hazards consideration evaluation provided in Reference 3. The revised proposed Technical Specification pages are provided in Enclosure 2. Enclosure 2 provides a complete replacement set of the proposed Technical Specification pages previously submitted in References 3 and 4.

No new regulatory commitments are established by this submittal. If any additional information is needed, please contact David J. Distel at (610) 765-5517.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 12th day of December, 2006.

Respectfully,

9GK Pamela B. Cowan

Pamela B. Cowan
Director - Licensing & Regulatory Affairs
AmerGen Energy Company, LLC

Enclosures: 1) Response to Request for Additional Information
2) Revised TS Page Markups

cc: S. J. Collins, USNRC Administrator, Region I
F. E. Saba, USNRC Project Manager, TMI Unit 1
D. M. Kern, USNRC Senior Resident Inspector, TMI Unit 1
File No. 06007

ENCLOSURE 1

TMI UNIT 1

**RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
TECHNICAL SPECIFICATION CHANGE REQUEST No. 331
APPLICATION FOR TECHNICAL SPECIFICATION IMPROVEMENT REGARDING
STEAM GENERATOR TUBE INTEGRITY**

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION TMI UNIT 1 TECHNICAL SPECIFICATION CHANGE REQUEST No. 331 APPLICATION FOR TECHNICAL SPECIFICATION IMPROVEMENT REGARDING STEAM GENERATOR TUBE INTEGRITY

NRC Request For Additional Information - Letter dated November 9, 2006:

1. **NRC Question**

You proposed to delete reference to sleeving as a repair method in the TMI-1 TSs. You indicated that TMI-1 will not install additional sleeves without prior NRC approval. However, there are sleeves currently installed at TMI-1. Please provide the inspection and repair criteria, including technical bases, for the existing sleeved tubes. Please discuss how your proposed TS 6.19, "Steam Generator (SG) Program," ensures that sleeved tube integrity is maintained. Also, clarify whether you are planning to add the above described criteria in the TMI-1 TSs. If not, explain.

Response

Marked-up, proposed Technical Specification (TS) pages have been provided in Enclosure 2. Inspection and repair criteria for the sleeves have been incorporated to ensure maintenance of sleeved tube integrity. Note that, as discussed with the staff, the proposed TSs have been revised to incorporate the existing sleeves; since no new sleeve installations are planned at TMI-1 without NRC prior approval, the proposed TSs reflect the presence of the existing sleeve population and do not cover the installation of new sleeves.

The following are the technical bases for the proposed TS pages:

TMI Unit 1 Sleeve Design

The design analyses and testing of the TMI Unit 1 Alloy 690 rolled sleeves were performed by the B&W Nuclear Services Company and were based on previous qualifications performed for Alloy 600 sleeves. Reference 1, below, was the qualification for the TMI-1 Alloy 690 sleeves. This report was submitted by the B&W Nuclear Services Company to the NRC for review and approval on March 26, 1991 (Reference 2). The NRC approved this qualification report "...for referencing in license applications" in Reference 3.

All of the TMI Unit 1 sleeves are installed in the steam generator's upper tubesheets and are 80" long, extending from the upper tubesheet down through the 15th tube support plate. The upper sleeve roll-expanded joint is captured within the upper tubesheet; the lower roll expansion is a 'freespan' joint. The sleeves were designed, fabricated, and installed as safety-related ASME Class I components.

All of the TMI Unit 1 sleeves are manufactured from Alloy 690, a corrosion-resistant material that is used for new steam generator tubes. While plants with Alloy 600 sleeves have detected sleeve degradation; plants with Alloy 690 sleeves have not detected significant corrosion to date. In addition to being corrosion-resistant, the TMI Unit 1 sleeves are stronger than the plant's original steam generator tubing. (The steam generator tubing has a 0.034" minimum wall thickness; the sleeves have a 0.045" minimum wall thickness.

The design sleeve loads assumed a 360-degree severance was present in the parent tubing 'behind' the sleeve.)

The TMI Unit 1 upper sleeve rolled expansion joints are captured within kinetic expanded tubing in the upper tubesheets. At this location they are protected from secondary side loose parts and tube bending loads. These joints are also in compression since the sleeves were expanded into the parent tubing and tubesheets. The compressive loads, along with the corrosion-resistant material of construction, minimize the joints' subsequent susceptibility to stress corrosion cracking.

The qualification reports for the sleeves were extensive and addressed the following areas:
- Leakage tests
- Joint strength tests
- Light expansion tests
- Corrosion tests
- Flow-induced vibration analysis
- Strain tests
- Adjacent tube tests
- Thermal/hydraulic effects of sleeving
- Structural and functional integrity of the sleeves

<u>TMI Sleeve Population</u>

TMI Unit 1 installed 125 sleeves in each of its two steam generators during 1991 Outage 9R. (This work was reported to the NRC in Reference 4.) TMI Unit 1 installed 124 sleeves in its "A" steam generator, and 128 sleeves in its "B" steam generator, during 1993 Outage 10R. (The work was reported to the NRC in Reference 5.)

- One of the sleeved tubes in the "A" steam generator, A66-1, was plugged during 1995 Outage 11R due to an indication between the 4th and 5th tube support plate (which is outside the installed sleeve area).

- One of the sleeved tubes in the "A" steam generator, A68-7, was plugged in 2003 Outage 1R15 due to an indication at the lower tube end (which is outside the installed sleeve area).

- One of the sleeved tubes in the "B" steam generator, B68-4, was plugged in 2003 Outage 1R15 due to an indication at the lower tube end (which is outside the installed sleeve area).

The plugging of these sleeved tubes was reported to the NRC in the respective outage reports. The result is that TMI Unit 1 has 247 sleeved tubes currently in service in the "A" steam generator and 252 sleeved tubes in service in the "B" steam generator.

Reasons for Sleeve Installation

TMI Unit 1, along with all of the other operating Once-Through Steam Generator (OTSG) plants, installed sleeves in order to prevent high-cycle fatigue cracks in tubes in the "lane-wedge" areas of the steam generator tube bundles. An untubed lane for future tube bundle visual inspections was a design feature of the original OTSGs; however this design feature resulted in excessive vibration of the tubes located adjacent/nearby the untubed lane, in the lane-wedge area. Tubes in this area were prone to vibration-induced failures near the Upper Tube Sheet (UTS) faces. A large number of primary-to-secondary leaks and leaker outages occurred at the OTSG plants as a result of fatigue cracks at the upper lengths of these tubes, so 80" long sleeves were installed to stabilize them. These sleeves were, and continue to be, very effective in preventing the lane-wedge tube cracking – prior to installing the sleeves about 77% (40 of 52) of the OTSG tube leaks were from tubes within the preventive sleeving zone. Since 1994 there have been no tube leaks from tubes within the preventive sleeving zones. (Approximately 3600 of these 80" long sleeves, of both Alloy 600 and Alloy 690, were installed in the various U.S. OTSGs. The original OTSGs at 4 of the 7 B&W-designed operating plants have been recently replaced, and their sleeves have been removed from service. Rancho Seco plant OTSG tubing was also sleeved, but that plant has been shutdown since 1989.) The only steam generator tube leaker outage at TMI Unit 1 occurred as a result of a high-cycle fatigue failure in a tube in the area of the steam generator tube bundles that has since been preventively sleeved. In summary, there is sufficient technical data and operating experience to indicate that the TMI Unit 1 installed sleeves have been very effective in preventing tube leaks, and thus supporting the position that the TMI Unit 1 sleeves should remain in service to continue to prevent tube leaks.

Some small parent tube eddy current imperfections located below the UTS kinetic expansions were "covered" (i.e., removed from service) by the TMI Unit 1 sleeves. However, of the 502 sleeves that were originally installed in the TMI Unit 1 steam generators, only one (1) sleeve was installed to repair a tube with a repairable indication (-as opposed to being installed for the preventive reasons described above.) This tube, A74-30, had an ID-initiated indication >40% throughwall (TW) in the upper tubesheet portion of the tube and was sleeved in 1993 Outage 10R as reported to the NRC in Reference 5.

Additional Sleeve Qualification Testing for TMI Unit 1

The TMI Unit 1 sleeves were installed consistent with their qualification report. However, the TMI Unit 1 upper sleeve roll joints differed slightly from those of the sleeves installed at the other OTSG plants. The tubing in the TMI Unit 1 upper tubesheet joints was damaged in the early 1980's and repaired by a kinetic expansion process. (This kinetic expansion process was another effective repair and was approved by the NRC Safety Evaluation Report documented under NUREG 1019. Kinetic expansion examination and repair criteria, including treatment of the sleeves, were recently approved by the NRC in Reference 6.)

All of the TMI Unit 1 sleeves were installed in parent tubing that had previously been degraded within the upper tubesheet and had been repaired by kinetic expansion. The sleeves were originally qualified for typical OTSG 1" nominal rolled expansions into tubing with existing flaws up to 20% TW. (These were the qualification's pre-sleeving eddy current acceptance criteria for the upper tubesheet sleeve expansions.)

Additional testing was performed for the TMI Unit 1 sleeve installation into kinetic expanded tubing. To provide additional evaluation of the acceptability of the sleeves for the TMI Unit 1 upper tubesheet parent tubing prior to their installation, additional testing was performed on roll joints with degraded parent tubing.

In addition, the sleeves at the other OTSG plants were installed over their original 1" nominal parent tube roll expansions. Approximately 2/3 of the sleeve roll expansion length was placed over the original rolled joints, and 1/3 of the new sleeve expansions were placed over unexpanded parent tubing. This differed from the TMI Unit 1 sleeve upper joints, where the full length of the sleeve upper expansion would be into kinetic expanded tubing. Analysis and testing showed that when a sleeve was installed into a fully expanded tube, as in the TMI Unit 1 case, the entire delivered energy from the roll expander was used to achieve wall thinning of the sleeve (vice some fraction of the expander energy used to expand the length of unexpanded parent tube). The result was a tighter sleeve-to-tube joint for the TMI Unit 1 upper sleeve joint configuration.

<u>Sleeve Examinations</u>

Parent tube examinations were performed prior to TMI Unit 1 sleeve installations. In addition, post-installation examinations were conducted on each of the sleeves when they were installed in 1991 and 1993.

Since sleeve installation, TMI Unit 1 has continued to perform an extensive eddy current examination scope on its in-service sleeves, considering that they are manufactured from corrosion-resistant Alloy 690 material. During the plant's most recent outage in the Fall of 2005, 33% of the sleeve upper expansions and 100% of the sleeve lower expansions were examined with MRPC/PlusPoint probes, and 33% of the sleeve unexpanded lengths were examined with bobbin probes. This scope is also currently planned for the plant's forthcoming Fall 2007 outage, and is reflected in the attached proposed TS page markups. In addition, TMI Unit 1 has committed to a stringent repair criterion for these examinations (i.e., 'plug on detection') that was approved by the NRC staff in Reference 6. The original sleeve qualification work demonstrated that a 40% through-wall (TW) sleeve defect could be tolerated and justified a sleeve plugging criteria of 40% TW. Therefore, the TMI Unit 1 sleeve plugging criterion is more stringent than the original qualification/analysis.

Examinations are not performed on the parent tubing behind the TMI Unit 1 upper sleeve roll expansions, which is known to be degraded and was the reason for kinetic expansion tube repairs and the additional qualification work described above. The probability of further parent tube degradation at this location is small for the reasons described above (e.g., corrosion-resistant sleeve material covers the parent tubing, compressive loads, etc.) The condition of the TMI Unit 1 parent tubing behind the upper sleeve roll expansions is analogous to the condition of parent tubing behind the thousands of Alloy 690 rolled tube plugs in the industry. Rolled plug-to-tubesheet joints have been successfully utilized in these installations without subsequent inspection of the parent tubing behind the plugs; further structural or leakage-significant degradation of the parent tubing is not anticipated, and this area is not typically inspected and is often known to be degraded prior to plug installation.

Projected Sleeve Leakage

The projected leakage from the TMI Unit 1 sleeves during a hypothetical Main Steam Line Break is low. Based on its review of the qualification report, the NRC staff (in Reference 3) found that the sleeve-to-tube joints had acceptable leak tightness. The qualification report (Reference 3, Page 6-23) gives the tested leakage as: "The combined leak rate during the maximum accident load, from 2500 installed sleeves into tubes with through wall defects, would be 2.34 gal/hr..." Given that TMI Unit 1 has 252 in-service sleeves in its "most-sleeved" steam generator, this equates to approximately a tenth (i.e. 252/2500) of that value. Therefore, the projected leakage from the TMI Unit 1 installed sleeves is bounded by the leakage addressed in BAW-2120P.

Since their installation in 1991 and 1993, TMI Unit 1 sleeve leakage has been monitored during the plant's operation by the plant's primary-to-secondary leak monitoring program, including radiation monitors and periodic sampling of the primary and secondary systems. Primary-to-secondary leakage from the plant's steam generators has been very low during recent plant operating cycles (typically less than 1 or 2 gallons per day.) Sleeve leakage has not been encountered at TMI Unit 1 since their 1991 and 1993 installations.

Summary

Given the above, the TMI Unit 1 sleeves were installed consistent with the appropriate requirements and criteria contained in the NRC approved Topical Report BAW-2120P. The subject sleeves, to date, have effectively prevented tube leaks at TMI Unit 1 and at other OTSG plants. Therefore, the proposed TMI Unit 1 Technical Specification (TS) changes incorporating TSTF-449 requirements have included the existing installed sleeves and their associated inspection and repair criteria, described above. Since no new sleeve installations are planned at TMI Unit 1 without NRC prior site specific approval, the proposed TS changes reflect the presence of the existing sleeve population and do not cover the installation of new sleeves.

References

1. BAW-2120P, Revision 0, "OTSG 80" Mechanical Sleeve Qualification (Alloy 690)", B&W Nuclear Services Company, January 1991.

2. B&W Nuclear Technologies Letter, J.H. Taylor to U.S.N.R.C., "BWNS Topical Report BAW-2120P", March 26, 1991.

3. U.S.N.R.C. Letter to B&W Nuclear Services Company, J. E. Richardson to J.H. Taylor, "Acceptance for Referencing of Topical Report BAW-2120P, Rev. 0, "OTSG 80 Inch Mechanical Sleeve Qualification (Alloy 690)", August 1, 1991.

4. GPU Nuclear Letter C311-92-2130, T. G. Broughton to U.S.N.R.C., "Refueling Interval 9R Once Through Steam Generator (OTSG) Tube Inspection Report", October 4, 1992.

5. GPU Nuclear Letter C311-94-2127, T.G. Broughton to U.S.N.R.C., "Refueling Interval 10R Once Through Steam Generator (OTSG) Tube Inspection Report", October 4, 1994.

6. U.S.N.R.C. Letter to AmerGen Energy Company, P.S.Tam to C. M. Crane, "Three Mile Island Nuclear Station, Unit 1 - Steam Generator Tube Kinetic Expansion and Repair Criteria (TAC No. MC7001)", November 8, 2005.

NRC Request For Additional Information - Letter dated August 14, 2006:

9. **NRC Question**

On Page 4-78, the proposed Limiting Condition of Operation (LCO) for TS Section 3.1.1.2.b, third paragraph states that "...a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it,..." Please discuss your plans to modify the proposed LCO to remove "and any repairs made to it" given that TMI-1 does not have approved SG tube repair methods.

Response

TMI Unit 1 installed tube sleeves in the past as a repair method and these sleeves remain in service. Therefore, the phrase "and any repairs made to it" should be retained in the definition of a SG tube. It is noted (in the response to Question 1, above) that any future installation of sleeve repairs would require site specific NRC approval.

14. **NRC Question**

Given that TMI-1 does not have approved SG tube repair methods, discuss your plans to remove TS Section 6.9.6.i. In addition, for the same reason, discuss your plans to modify TS Section 6.19 by deleting Section 6.19.f.

Response

The previously proposed TS Section 6.9.6.i is consistent with the TSTF-449, Revision 1, and contains the qualifying phrase, "if any" to accommodate plants that may not have approved SG tube repair methods. As described in the response to Question 1, above, TMI Unit 1 installed tube sleeves in the past as a repair method and these sleeves remain in service. Accordingly, the proposed TS Section 6.19.f has been modified to clarify that 80-inch sleeves installed in 1991 and 1993 may remain in service, and that future installation of new sleeves or other new repair methods requires site specific NRC approval prior to installation. The revised TS page markup is provided in Enclosure 2.

16. **NRC Question**

In addition, discuss your plans to remove reference to "and tube repairs" in proposed TS Section 6.9.6.h.

Response

(Refer to the response to Question 1, above.) The phrase "and tube repairs" was retained in proposed TS Section 6.9.6.h since TMI Unit 1 has approximately 500 sleeves in service and these sleeves influence the effective plugging percentage reported under that TS section.

17. **NRC Question**

The NRC staff is aware that sleeves were installed in the TMI-1 SGs to stiffen the tubes and not as a SG tube repair method. Please confirm that the tube repair criteria (≥40-percent through-wall) is being applied to the parent tube behind the sleeves including the sleeve-to-tube joint. If the repair criteria is not being implemented for the required length of "defect free joint," discuss your plans for submitting the sleeving method for approval as a repair technique.

Response

The current TMI Unit 1 TS Section 4.19.4(b) refers to sleeving as a repair method. TMI Unit 1 sleeves were installed in 1991 and 1993 and remain in service. The 40% through-wall criterion is not applied to the parent tube at the sleeve-to-tube joint in the upper tubesheet. TMI Unit 1 ECR # 02-01121, "Inspection Acceptance Criteria and Leakage Assessment Methodology for TMI OTSG Kinetic Expansion Examinations," Revision 2, Section 2.7, approved by the NRC in an SER dated November 8, 2005, describes the installed sleeves, the scope of associated examinations for sleeved tubes, and the repair criterion used to disposition degradation detected in sleeved tubes. (Refer also to the response to Question 1, above.)

ENCLOSURE 2

TMI Unit 1 Technical Specification Change Request No. 331

Revised Markup of Proposed License, Technical Specifications, and Bases Page Changes

Revised License Pages

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Revised Technical Specifications & Bases Pages

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(8) Repaired Steam Generators - DELETED

In order to confirm the leak-tight integrity of the Reactor Coolant System, including the steam generators, operation of the facility shall be in accordance with the following:

1. Prior to initial criticality, the licensee shall submit to NRC the results of the steam generator hot test program and a summary of its management review.

2. The licensee shall confirm baseline primary-to-secondary leakage rate established during the steam generator hot test program. If leakage exceeds the baseline leakage rate by more than 0.1 gpm*, the facility shall be shut down and leak tested. If any increased leakage above baseline is due to defects in the tube free span, the leaking tube(s) shall be removed from service. The baseline leakage shall be re-established, provided that the leakage limit of Technical Specification 3.1.6.3 is not exceeded.

3. The licensee shall complete its post-critical test program at each power range (0-5%, 5%-50%, 50%-100%) in conformance with the program described in Topical Report 008, Rev. 3, and shall have available the results of that test program and a summary of its management review, prior to ascension from each power range and prior to normal power operation.

4. The licensee shall conduct eddy-current examinations, consistent with the extended inservice inspection plan defined in Table 3.3-1 of NUREG-1019, either 90 calendar days after reaching full power, or 120 calendar days after exceeding 50% power operation, whichever comes first. In the event of plant operation for an extended period at less than 50% power, the licensee shall provide an assessment at the end of 180 days of operation at power levels between 5% and 50%, such assessment to contain recommendations and supporting information as to the necessity of a special eddy-current testing (ECT) shutdown before the end of the refueling cycle. (The NRC staff will evaluate that assessment and determine the time of the next eddy-current examination, consistent with the other provisions of the license conditions.) In the absence of such an assessment, a special ECT shutdown shall take place before an additional 30 days of operation at power above 5%.

*If leakage exceeds the baseline leakage rate by more than 0.1 gpm during the remainder of the Cycle 8 operation, the facility shall be shutdown and leak tested. Operation at leakage rates of up to 0.2 gpm above the baseline leakage rate shall be acceptable during the remainder of Cycle 8 operation. After the 9R refueling outage, the leakage limit and accompanying shutdown requirements revert to 0.1 gpm above the baseline leakage rate.

5. The licensee shall provide routine reporting of the long-term corrosion "lead tests" test results on a quarterly basis as well as more timely notification if adverse corrosion test results are discovered.

(9) Long Range Planning Program - Deleted

Sale and License Transfer Conditions

(10) Deleted

(11) Deleted

(12) Deleted

(13) Deleted

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3.1 REACTOR COOLANT SYSTEM

3.1.1 OPERATIONAL COMPONENTS

Applicability

Applies to the operating status of reactor coolant system components.

Objective

To specify those limiting conditions for operation of reactor coolant system components which must be met to ensure safe reactor operations.

Specification

3.1.1.1 Reactor Coolant Pumps

a. Pump combinations permissible for given power levels shall be as shown in Specification Table 2.3.1.

b. Power operation with one idle reactor coolant pump in each loop shall be restricted to 24 hours. If the reactor is not returned to an acceptable RC pump operating combination at the end of the 24-hour period, the reactor shall be in a hot shutdown condition within the next 12 hours.

c. The boron concentration in the reactor coolant system shall not be reduced unless at least one reactor coolant pump or one decay heat removal pump is circulating reactor coolant.

3.1.1.2 Steam Generator (SG) Tube Integrity

INSERT

a. ~~Both steam generators shall be operable whenever the reactor coolant average temperature is above 250°F.~~

3.1.1.3 Pressurizer Safety Valves

a. The reactor shall not remain critical unless both pressurizer code safety valves are operable with a lift setting of 2500 psig ± 1%.

b. When the reactor is subcritical, at least one pressurizer code safety valve shall be operable if all reactor coolant system openings are closed, except for hydrostatic tests in accordance with ASME Boiler and Pressure Vessel Code, Section III.

INSERT TO TS PAGE 3-1a (REVISED TS 3.1.1.2)

a. Whenever the reactor coolant average temperature is above 200°F, the following conditions are required:

(1.) SG tube integrity shall be maintained.

AND

(2.) All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program. (The Steam Generator Program is described in Section 6.19.)

ACTIONS:

---NOTE---

Entry into Sections 3.1.1.2.a.(3.) and (4.), below, is allowed for each SG tube. If the requirements of Sections 3.1.1.2.a.(1.) or 3.1.1.2.a.(2.) were not met for one or more tubes then perform the following.

(3.) With one or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program:

a. Verify within 7 days that tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection, AND

b. Plug the affected tube(s) in accordance with the Steam Generator Program prior to exceeding a reactor coolant average temperature of 200°F following the next refueling outage or SG tube inspection.

(4.) If Action 3., above, is not completed within the specified completion times, or SG tube integrity is not maintained, be in HOT SHUTDOWN within 6 hours and be in COLD SHUTDOWN within 36 hours.

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Bases

The limitation on power operation with one idle RC pump in each loop has been imposed since the ECCS cooling performance has not been calculated in accordance with the Final Acceptance Criteria requirements specifically for this mode of reactor operation. A time period of 24 hours is allowed for operation with one idle RC pump in each loop to effect repairs of the idle pump(s) and to return the reactor to an acceptable combination of operating RC pumps. The 24 hours for this mode of operation is acceptable since this mode is expected to have considerable margin for the peak cladding temperature limit and since the likelihood of a LOCA within the 24-hour period is considered very remote.

A reactor coolant pump or decay heat removal pump is required to be in operation before the boron concentration is reduced by dilution with makeup water. Either pump will provide mixing which will prevent sudden positive reactivity changes caused by dilute coolant reaching the reactor. One decay heat removal pump will circulate the equivalent of the reactor coolant system volume in one-half hour or less.

The decay heat removal system suction piping is designed for 300°F and 370 psig; thus, the system can remove decay heat when the reactor coolant system is below this temperature (References 1, 2, and 3).

Both steam generators must ~~be operable~~ have tube integrity before heatup of the Reactor Coolant System to insure system integrity against leakage under normal and transient conditions. Only one steam generator is required for decay heat removal purposes.

One pressurizer code safety valve is capable of preventing overpressurization when the reactor is not critical since its relieving capacity is greater than that required by the sum of the available heat sources which are pump energy, pressurizer heaters, and reactor decay heat. Both pressurizer code safety valves are required to be in service prior to criticality to conform to the system design relief capabilities. The code safety valves prevent overpressure for a rod withdrawal or feedwater line break accidents (Reference 4). The pressurizer code safety valve lift set point shall be set at 2500 psig ±1% allowance for error. **Surveillance requirements are specified in the Inservice Testing Program. Pressurizer code safety valve setpoint drift of up to 3% is acceptable in accordance with ASME Section XI** (Reference 5) **and the assumptions of TMI-1 safety analysis.**

Refer to Section 3.1.6.3 for allowable primary-to-secondary leakage. Refer to Section 4.19 for Bases for Steam Generator tube integrity.

References

(1) UFSAR, Tables 9.5-1 and 9.5-2

(2) UFSAR, Sections 4.2.5.1 and 9.5 – "Decay Heat Removal"

(3) UFSAR, Section 4.2.5.4 – "Secondary System"

(4) UFSAR, Section 4.3.10.4 – "System Minimum Operational Components"

(5) UFSAR, Section 4.3.7 – "Overpressure Protection"

3.1.6 LEAKAGE

Applicability

Applies to reactor coolant leakage from the reactor coolant system and the makeup and purification system.

Objective

To assure that any reactor coolant leakage does not compromise the safe operation of the facility.

Specification

3.1.6.1 If the total reactor coolant leakage rate exceeds 10 gpm, the reactor shall be placed in hot shutdown within 24 hours of detection.

3.1.6.2 If unidentified reactor coolant leakage (excluding normal evaporative losses) exceeds one gpm or if any reactor coolant leakage is evaluated as unsafe, the reactor shall be placed in hot shutdown within 24 hours of detection.

3.1.6.3 If the sum of the primary-to-secondary leakage from both steam generators ~~through the steam generator tubes~~ exceeds 0.1 gpm (144 GPD), ~~1 gpm total for both steam generators,~~ the reactor shall be placed in hot shutdown within 6 hours, and the reactor shall be placed in cold shutdown within 36 hours. ~~of detection.~~

3.1.6.4 If any reactor coolant leakage exists through a nonisolable fault in an RCS strength boundary (such as the reactor vessel, piping, valve body, etc., except the steam generator tubes), the reactor shall be shutdown, and a cooldown to the cold shutdown condition shall be initiated within 24 hours of detection.

3.1.6.5 If reactor shutdown is required by Specification 3.1.6.1, 3.1.6.2, 3.1.6.3, or 3.1.6.4, the rate of shutdown and the conditions of shutdown shall be determined by the safety evaluation for each case.

3.1.6.6 Action to evaluate the safety implication of reactor coolant leakage shall be initiated within four hours of detection. The nature, as well as the magnitude, of the leak shall be considered in this evaluation. The safety evaluation shall assure that the exposure of offsite personnel to radiation is within the dose rate limits of the ODCM.

3.1.6.7 If reactor shutdown is required per Specification 3.1.6.1, 3.1.6.2, 3.1.6.3 or 3.1.6.4, the reactor shall not be restarted until the leak is repaired or until the problem is otherwise corrected.

3.1.6.8 When the reactor is critical and above 2 percent power, two reactor coolant leak detection systems of different operating principles shall be in operation for the Reactor Building with one of the two systems sensitive to radioactivity. The systems sensitive to radioactivity may be out-of-service for no more than 72 hours provided a sample is taken of the Reactor Building atmosphere every eight hours and analyzed for radioactivity and two other means are available to detect leakage.

Bases (Continued)

The unidentified reactor coolant leakage limit of 1 gpm is established as a quantity which can be accurately measured while sufficiently low to ensure early detection of leakage. Leakage of this magnitude can be reasonably detected within a matter of hours, thus providing confidence that cracks associated with such leakage will not develop into a critical size before mitigating actions can be taken.

Total reactor coolant leakage is limited by this specification to 10 gpm. This limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of unidentified leakage.

~~The sum of the primary-to-secondary leakage ~~through the~~ from both steam generators ~~tubes~~ is limited to ~~1 gpm total~~ 0.1 gpm (144 GPD). This limit ensures that the dosage contribution from ~~tube~~ leakage will be limited to a small fraction of Part 100 limits in the event of a steam line break. Steam generator primary-to-secondary leakage is quantified by analysis of secondary plant activity.~~

If reactor coolant leakage is to the auxiliary building, it may be identified by one or more of the following methods:

a. The auxiliary and fuel handling building vent radioactive gas monitor is sensitive to very low activity levels and would show an increase in activity level shortly after a reactor coolant leak developed within the auxiliary building.

b. Water inventories around the auxiliary building sump.

c. Periodic equipment inspections.

d. In the event of gross leakage, in excess of 13 gpm, the individual cubicle leak detectors in the makeup and decay heat pump cubicles, will alarm in the control room to backup "a", "b", and "c" above.

When the source and location of leakage has been identified, the situation can be evaluated to determine if operation can safely continue. This evaluation will be performed by TMI-1 Plant Operations.

INSERT

REFERENCES

(1) NEI 97-06, "Steam Generator Program Guidelines."

INSERT TO TS PAGE 3-15a (BASES FOR SECTION 3.1.6)

Except for primary to secondary leakage, the safety analyses do not address operational leakage. However, other operational leakage is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary leakage from all steam generators (SGs) is one gallon per minute or is assumed to increase to the leakage rates described in TS 6.19.c.2 as a result of accident-induced conditions. The TS requirement to limit primary to secondary leakage through both SGs to less than or equal to 144 gallons per day is significantly less than the conditions assumed in the safety analysis.

The limit of 144 gallons per day total for both SGs bounds the TSTF-449, Rev. 4 limit of 150 gallons per day per SG, which is based on the operational leakage performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 1). The Steam Generator Program operational leakage performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

Bases (Continued)

If EFW were required during surveillance testing, minor operator action (e.g., opening a local isolation valve or manipulating a control switch from the control room) may be needed to restore operability of the required pumps or flowpaths. An exception to permit more than one EFW Pump or both EFW flowpaths to a single OTSG to be inoperable for up to 8 hours during surveillance testing requires 1) at least one motor-driven EFW Pump operable, and 2) an individual involved in the task of testing the EFW System must be in communication with the control room and stationed in the immediate vicinity of the affected EFW flowpath valves. Thus the individual is permitted to be involved in the test activities by taking test data and his movement is restricted to the area of the EFW Pump and valve rooms where the testing is being conducted.

The allowed action times are reasonable, based on operating experience, to reach the required plant operating conditions from full power in an orderly manner and without challenging plant systems. Without at least two EFW Pumps and one EFW flowpath to each OTSG operable, the required action is to immediately restore EFW components to operable status, and all actions requiring shutdown or changes in Reactor Operating Condition are suspended. With less than two EFW pumps or no flowpath to either OTSG operable, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown. In such a condition, the unit should not be perturbed by any action, including a power change, which might result in a trip. The seriousness of this condition requires that action be started immediately to restore EFW components to operable status. TS 3.0.1 is not applicable, as it could force the unit into a less safe condition.

The EFW system actuates on: 1) loss of all four Reactor Coolant Pumps, 2) loss of both Main Feedwater Pumps, 3) low OTSG water level, or 4) high Reactor Building pressure. A single active failure in the HSPS will neither inadvertently initiate the EFW system nor isolate the Main Feedwater system. OTSG water level is controlled automatically by the HSPS system or can be controlled manually, if necessary.

The MSSVs will be able to relieve to atmosphere the total steam flow if necessary. Below 5% power, only a minimum number of MSSVs need to be operable as stated in Specifications 3.4.1.2.1 and 3.4.1.2.2. This is to provide OTSG overpressure protection during hot functional testing and low power physics testing. Additionally, when the Reactor is between hot shutdown and 5% full power operation, the overpower trip setpoint in the RPS shall be set to less than 5% as is specified in Specification 3.4.1.2.2. The minimum number of MSSVs required to be operable allows margin for testing without jeopardizing plant safety. Plant specific analysis shows that one MSSV is sufficient to relieve reactor coolant pump heat and stored energy when the reactor has been subcritical by 1% delta K/K for at least one hour. Other plant analyses show that two (2) MSSVs on either OTSG are more than sufficient to relieve reactor coolant pump heat and stored energy when the reactor is below 5% full power operation but had been subcritical by 1% delta K/K for at least one hour subsequent to power operation above 5% full power. ~~According to Specification 3.1.1.2a, both OTSGs shall be operable whenever the reactor coolant average temperature is above 250 degrees F.~~ This assures that all four (4) MSSVs are available for redundancy. During power operations at 5% full power or above, if MSSVs are inoperable, the power level must be reduced, as stated in Specification 3.4.1.2.3 such that the remaining MSSVs can prevent overpressure on a turbine trip.

Bases (Cont'd)

The equipment testing and system sampling frequencies specified in Tables 4.1-2, 4.1-3, and 4.1-5 are considered adequate to maintain the equipment and systems in a safe operational status.

REFERENCE

(1) UFSAR, Section 7.1.2.3(d) - "Periodic Testing and Reliability"
(2) NRC SER for BAW-10167A, Supplement 1, December 5, 1988.
(3) BAW-10167, May 1986.
(4) BAW-10167A, Supplement 3, February 1998.
(5) EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

INSERT

Amendment No. ~~181, 225, 255~~,

INSERT TO TS PAGE 4-2b (BASES FOR SECTION 4.1)

The primary to secondary leakage surveillance in TS Table 4.1-2, Item 12, verifies that primary to secondary leakage is less than or equal to 144 gallons per day total through both SGs. Satisfying the primary to secondary leakage limit ensures that the operational leakage performance criterion in the Steam Generator Program is met. If this surveillance is not met, compliance with TS 3.1.1.2, "Steam Generator (SG) Tube Integrity," and TS 3.1.6.3, should be evaluated. The 144 gallons per day limit is measured at room temperature. The operational leakage rate limit applies to leakage through both SGs.

The TS Table 4.1-2 primary to secondary leakage surveillance is modified by a Note, which states that the initial surveillance is not required to be performed until 12 hours after establishment of steady state POWER OPERATION. For RCS primary to secondary leakage determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The TS Table 4.1-2 primary to secondary leakage surveillance frequency of Daily is a reasonable interval to trend primary to secondary leakage and recognizes the importance of early leakage detection in the prevention of accidents. The primary to secondary leakage is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 5).

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TABLE 4.1-2

MINIMUM EQUIPMENT TEST FREQUENCY

Item	Test	Frequency
1. Control Rods	Rod drop times of all full length rods	Each Refueling shutdown
2. Control Rod Movement	Movement of each rod	Every 92 days, when reactor is critical
3. Pressurizer Safety Valves	Setpoint	In accordance with the Inservice Testing Program
4. Main Steam Safety Valves	Setpoint	In accordance with the Inservice Testing Program
5. Refueling System Interlocks	Functional	Start of each refueling period
6. (Deleted)	--	--
7. Reactor Coolant System Leakage	Evaluate	Daily, when reactor coolant system temperature is greater than 525 degrees F
8. (Deleted)	--	--
9. Spent Fuel Cooling System	Functional	Each refueling period prior to fuel handling
10. Intake Pump House Floor (Elevation 262 ft. 6 in.)	(a) Silt Accumulation - Visual inspection of Intake Pump House Floor	Not to exceed 24 months
	(b) Silt Accumulation Measurement of Pump House Flow	Quarterly
11. Pressurizer Block Valve (RC-V2)	Functional*	Quarterly
12. Primary to Secondary Leakage	Evaluate	Daily (Note: Initial primary to secondary leakage evaluation is not required to be performed until 12 hours after establishment of steady state POWER OPERATION)

* Function shall be demonstrated by operating the valve through one complete cycle of full travel.

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INSERT

STEAM GENERATOR (SG) TUBE INTEGRITY

4.19 ~~OTSG TUBE INSERVICE INSPECTION~~

Applicability

This Technical Specification applies to the inservice inspection of the OTSG tube portion of the reactor coolant pressure boundary.

Objective

The objective of this inservice inspection program is to provide assurance of continued integrity of the tube portion of the Once-Through Steam Generators, while at the same time minimizing radiation exposure to personnel in the performance of the inspection.

Specification

Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 3.1.6.3.

4.19.1 Steam Generator Sample Selection and Inspection Methods

a. Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 4.19.1 at the frequency specified in 4.19.3.

b. Inservice inspection of steam generator tubing shall include nondestructive examination by eddy-current testing or other equivalent techniques. The inspection equipment shall be calibrated to provide a sensitivity that will detect defects with a penetration of 20 percent or more of the minimum allowable as-manufactured tube wall thickness.

4.19.2 Steam Generator Tube Sample Selection and Inspection

The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 4.19.2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.19.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.19.4. The tubes selected for

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each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

a. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

1. All nonplugged tubes that previously had detectable wall penetrations (>20%).

2. At least 50% of the tubes inspected shall be in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 4.19.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

4. Tubes in the following groups may be excluded from the first random sample if all tubes in a group in both steam generators are inspected. No credit will be taken for these tubes in meeting minimum sample size requirements.

   (1) Group A-1: Tubes in rows 73 through 79 adjacent to the open inspection lane, and tubes between and on lines drawn from tube 66-1 to tube 75-15 and from 86-1 to 77-15.

   (2) Group A-2: Tubes having a drilled opening in the 15th support plate.

b. The tubes selected as the second and third samples (if required by Table 4.19.2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these second and third samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspection includes those portions of the tubes where imperfections were previously found.

c. Implementation of the repair criteria for Inside Diameter (ID) Inter-Granular Attack (IGA) requires 100% bobbin coil inspection of all non-plugged tubes in accordance with AmerGen Engineering Report, ECR No. TM 01-00328, during all subsequent steam generator inspection intervals pursuant to Section 4.19.3. ID IGA indications detected by the bobbin coil probe shall be characterized using rotating coil probes, as defined in that report.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected in a steam generator are degraded tubes and none of the inspected tubes are defective.

4.19.2 Specification (Continued)

C-2 One or more tubes, but not more than 1% of the total tubes inspected in a steam generator are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.

C-3 More than 10% of the total tubes inspected in a steam generator are degraded tubes or more than 1% of the inspected tubes are defective.

NOTES: (1) In all inspections, previously degraded tubes whose degradation has not been spanned by a sleeve must exhibit significant increase in the applicable degradation size measurement (> **0.24** volt bobbin coil amplitude increase for inside diameter IGA indications or > 10% further wall penetration for all other degradation) to be included in the above percentage calculations.

(2) Where special inspections are performed pursuant to 4.19.2.a.4, defective or degraded tubes found as a result of the inspection shall be included in determining the Inspection Results Category for that special inspection but need not be included in determining the Inspection Results Category for the general steam generator inspection.

4.19.3 Inspection Frequencies

The required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first (baseline) inspection was performed after 6 effective full power months but within 24 calendar months of initial criticality. The subsequent inservice inspections shall be performed not more than 24 calendar months after the previous inspection. If the results of two consecutive inspections for a given group of tubes* encompassing not less than 18 calendar months all fall into the C-1 category or demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval for that group may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.19-2 at 40 month intervals for a given group of tubes* fall into Category C-3 the inspection frequency for that group shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.19.3.a; the interval may then be extended to a maximum of once per 40 months.

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* A group of tubes means:
(a) All tubes inspected pursuant to 4.19.2.a.4, or
(b) All tubes in a steam generator less those inspected pursuant to 4.19.2.a.4

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.19-2 during the shutdown subsequent to any of the following conditions:

1. A seismic occurrence greater than the Operating Basis Earthquake.

2. A loss of coolant accident requiring actuation of engineering safeguards, or

3. A major main steam line or feedwater line break.

d. After primary-to-secondary tube leakage (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.1.6.3, an inspection of the affected steam generator will be performed in accordance with the following criteria:

1. If the leak is above the 14th tube support plate in a Group as defined in Section 4.19.2.a.4(1) all of the tubes in this Group in the affected steam generator will be inspected above the 14th tube support plate. If the results of this inspection fall into the C-3 category, additional inspections will be performed in the same Group in the other steam generator.

2. If the leaking tube is not as defined in Section 4.19.3.d.1, then an inspection will be performed on the affected steam generator(s) in accordance with Table 4.19-2.

4.19.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish, or contour of a tube from that required by fabrication drawing or specifications. Eddy current testing indications less than degraded tube criteria specified in a.3 below may be considered imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube containing:

(a) an inside diameter (I.D.) IGA indication with a bobbin coil indication $\geq$ 0.2 volt or $\geq$ 0.13 inches axial extent or $\geq$ 0.26 inches circumferential extent, or

(b) imperfections $\geq$ 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the repair limit. A tube containing a defect is defective.

6. Repair Limit means the extent of degradation at or beyond which the tube shall be repaired or removed from service because it may become unserviceable prior to the next inspection.

   This limit is equal to 40% of the nominal tube wall thickness. Inside diameter IGA indications shall be repaired or removed from service if they exceed an axial extent of 0.25 inches, or a circumferential extent of 0.52 inches, or a through wall degradation dimensions of ≥ 40% if assigned.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss of coolant accident, or a steam line or feedwater line break as specified in 4.19.3.c., above.

8. Tube Inspection means an inspection of the steam generator tube from the bottom of the upper tubesheet completely to the top of the lower tubesheet, except as permitted by 4.19.2.b.2, above.

9. Inside Diameter Inter-Granular Attack (IGA) Indication means an indication initiating on the inside diameter surface and confirmed by diagnostic ECT to have a volumetric morphology characteristic of IGA.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (removal from service by plugging, or repair by kinetic expansion, sleeving, or other methods, of all tubes exceeding the repair limit and all tubes containing throughwall cracks) required by Table 4.19-2.

4.19.5 Reports

a. DELETED

b. The complete results of the steam generator tube inservice inspection shall be reported to the NRC within 90 days following completion of the inspection and repairs (main generator breaker closure). The report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Location, bobbin coil depth estimate (if determined), bobbin coil amplitude (if determined), and axial and circumferential extent for each inside diameter IGA indication, and

4. Identification of tubes repaired or removed from service.

5. The number of tubes repaired or removed from service in each steam generator,

6. An assessment of growth of inside diameter IGA degradation in accordance with the volumetric ID IGA management program contained in AmerGen Engineering Report, ECR No. TM 01-00328, and

7. Results of in-situ pressure testing, if performed.

c. Results of steam generator tube inspections which fall into Category C-3 require notification in accordance with 10 CFR 50.72 prior to resumption of plant operation. The written follow-up of this report shall provide a description of investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence in accordance with 10 CFR 50.73.

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained.

The program for inservice inspection of steam generator tubes is based on modification of Regulatory Guide 1.83, Revision 1. In-service inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The Unit is expected to be operated in a manner such that the primary and secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the primary or secondary coolant chemistry is not maintained within these chemistry limits, localized corrosion may likely result.

The extent of steam generator tube leakage due to cracking would be limited by the secondary coolant activity, Specification 3.1.6.3.

The extent of cracking during plant operation would be limited by the limitation of total steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 1 gpm). Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and repaired or removed from service.

Wastage-type defects are unlikely with proper chemistry treatment of the primary or the secondary coolant. However, even if a defect would develop in service, it will be found during scheduled inservice steam generator tube examinations. For tubes with ID IGA indications, additional conservatism is being applied to evaluate circumferential and axial dimensions for determining final disposition of the tube. For ID IGA indications through wall dimension will continue to be assigned to those indications where amplitude response permits measuring through wall dimension. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness.

Removal from service by plugging, or repair by kinetic expansion, sleeving, or other methods, will be required for degradation equal to or in excess of 40% of the tube nominal wall thickness. Tubes with I.D. initiated intergranular degradation may remain in service without % T.W. sizing if the degradation morphology has been characterized as not crack-like by diagnostic eddy current inspection and the degradation is of limited circumferential and axial length to ensure tube structural integrity. Additionally, serviceability for accident leakage under the limiting postulated Main Steam Line Break (MSLB) accident will be evaluated by determining that this I.D. initiated degradation mechanism is inactive (e.g. comparison of the outage examination results with the results from past outages meets the requirements of AmerGen Engineering Report, ECR No. TM 01-00328) and by successful in-situ pressure testing of a sample of these degraded tubes to evaluate their accident leakage potential when in-situ pressure tests are performed.

Where experience in similar plants with similar water chemistry, as documented by USNRC Bulletins/Notices, indicate critical areas to be inspected, at least 50% of the tubes inspected should be from these critical areas. First sample inspections sample size may be modified subject to NRC review and approval.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3 on the first sample inspection (See Table 4.19.2), these results will be reported to NRC pursuant to the requirements of Specification 4.19.5.c. Such cases will be considered by the NRC on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy current inspection, and revision of the Technical Specifications, if necessary.

NOTE: The eddy current examination voltages referred to in this section (section 4.19) are based on a normalization procedure that sets the bobbin coil prime frequency peak-to-peak response from the four 20% through-wall holes of an ASME calibration standard to 4 volts.

TABLE 4.19-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE

INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	None
No. of Steam Generators per Unit	Two
First Inservice Inspection	Two
Second & Subsequent Inservice Inspections	One[1]

TABLE NOTATION:

1. The Inservice Inspection may be limited to one steam generator on a rotating schedule encompassing 6% of the tubes in that steam generator if the results of the first and subsequent inspections indicate that both steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one steam generator may be found to be more severe than those in the other steam generator. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

TABLE 4.19-2

STEAM GENERATION TUBE INSPECTION(2)

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.(1)	C-1	None	N/A	N/A	N/A	N/A
	C-2	Plug or repair defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N/A	N/A
			C-2	Plug or repair defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug or repair defective tubes.
			C-3	Perform action for C-3 result of first sample.	C-3	Perform action for C-3 result of first sample.
	C-3	Inspect all tubes in this S.G., plug or repair defective tubes and inspect 2S tubes in other S.G. Provide notification to NRC pursuant to 10CFR50.72.b.2.i and submit a report pursuant to 10CFR50.73.-a.2.ii.	Other S.G. is C-1	None	N/A	N/A
			Other S.G. is C-2	Perform action for C-2 result of second sample	N/A	N/A
			Other S.G. is C-3	Inspect all tubes in each S.G. and plug or repair defective tubes. Provide notification to NRC pursuant to 10CFR50.72 b.2.i and submit a report pursuant to 10CFR50.73.a.2.ii.	N/A	N/A

Notes: (1) $S = 3 \frac{N}{n} \%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection.

(2) For tubes inspected pursuant to 4.19.2.a.4: No action is required for C-1 results. For C-2 results in one or both steam generators plug or repair defective tubes. For C-3 results in one or both steam generators, plug or repair defective tubes and provide notification to NRC pursuant to 10 CFR 50.72.b.2.i followed by a written report pursuant to 10 CFR 50.73.a.2.ii.

INSERT TO TS PAGE 4-77 (REVISED TS 4.19)

4.19 STEAM GENERATOR (SG) TUBE INTEGRITY

Applicability: Whenever the reactor coolant average temperature is above 200°F

Surveillance Requirements (SR):

Each steam generator shall be determined to be OPERABLE by performance of the following:

4.19.1 Verify SG tube integrity in accordance with the Steam Generator Program.

4.19.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program prior to exceeding an average reactor coolant temperature of 200°F following an SG tube inspection.

BASES:

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG.

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 6.19, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 6.19, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and

BACKGROUND (continued)

operational leakage. The SG performance criteria are described in Specification 6.19. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is only briefly released to the atmosphere via safety valves and the majority is discharged to the main condenser.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary leakage from all SGs of 1 gallon per minute or is assumed to increase to the leakage rates described in TS 6.19.c.2 as a result of accident-induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is conservatively assumed to be equal to, or greater than, the TS 3.1.4, "Reactor Coolant System Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO TS 3.1.1.2.a

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged in accordance with the Steam Generator Program.

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall and any repairs made to it, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

LCO (continued)

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 6.19, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational leakage. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary leakage caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm per SG, except for specific types of degradation at specific locations

LCO (continued)

where the NRC has approved greater accident induced leakage. (Refer to TS 6.19.c for specific types of degradation and approved repair criteria.) The accident induced leakage rate includes any primary to secondary leakage existing prior to the accident in addition to primary to secondary leakage induced during the accident.

The operational leakage performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational leakage is contained in TS 3.1.6.3, "LEAKAGE," and limits primary to secondary leakage through the SGs to 144 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of leakage is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced when the reactor coolant system average temperature is above 200°F.

RCS conditions are far less challenging when average temperature is at or below 200°F; primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for leakage.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

<u>3.1.1.2.a.(3.)a. and 3.1.1.2.a.(3.)b.</u>

3.1.1.2.a.(3.) applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator Program as required by Surveillance Requirement 4.19.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, 3.1.1.2.a.(4.) applies.

ACTIONS (continued)

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action 3.1.1.2.a.(3.)b. allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to exceeding a reactor coolant average temperature of 200°F following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

<u>3.1.1.2.a.(4.)</u>

If the Required Actions and associated Completion Times of Condition 3.1.1.2.a.(3.) are not met or if SG tube integrity is not being maintained, the reactor must be brought to HOT SHUTDOWN within 6 hours and COLD SHUTDOWN within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENT SR 4.19.1:

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, "Steam Generator Program Guidelines" (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the "as found" condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube repair criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also

SURVEILLANCE REQUIREMENTS (continued)

specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, non-destructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the frequency of SR 4.19.1. The frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 6.19 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SURVEILLANCE REQUIREMENT SR 4.19.2:

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 6.19 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

Tubes with inside diameter (ID) initiated intergranular degradation may remain in service without percent throughwall sizing if the degradation has been characterized as not crack-like by diagnostic eddy current inspection and if the degradation is of limited circumferential and axial length to ensure tube structural integrity. Additionally, serviceability for accident leakage under the limiting postulated Main Steam Line Break (MSLB) accident will be evaluated by determining that this ID initiated degradation mechanism is inactive (e.g., comparison of the outage examination results with the results from past outages meets the requirements of AmerGen Engineering Report ECR No. TM 01-00328) and by successful in-situ pressure testing of a sample of these degraded tubes to evaluate their accident leakage potential when in-situ pressure tests are performed.

The frequency of "prior to exceeding an average reactor coolant temperature of 200°F following an SG tube inspection" ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines".
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 100.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines".

(Pages 4-84 through 4-85 deleted)

6.9.5 CORE OPERATING LIMITS REPORT

6.9.5.1 The core operating limits addressed by the individual Technical Specifications shall be established and documented in the CORE OPERATING LIMITS REPORT prior to each reload cycle or prior to any remaining part of a reload cycle.

6.9.5.2 The analytical methods used to determine the core operating limits addressed by the individual Technical Specifications shall be those previously reviewed and approved by the NRC for use at TMI-1, specifically:

(1) BAW-10179 P-A, "Safety and Methodology for Acceptable Cycle Reload Analyses." *The current revision level shall be specified in the COLR.*

(2) TR-078-A, "TMI-1 Transient Analyses Using the RETRAN Computer Code", Revision 0. NRC SER dated 2/10/97.

(3) TR-087-A, "TMI-1 Core Thermal-Hydraulic Methodology Using the VIPRE-01 Computer Code", Revision 0. NRC SER dated 12/19/96.

(4) TR-091-A, "Steady State Reactor Physics Methodology for TMI-1", Revision 0. NRC SER dated 2/21/96.

(5) TR-092P-A, "TMI-1 Reload Design and Setpoint Methodology", Revision 0. NRC SER dated 4/22/97.

(6) BAW-10227P-A, "Evaluation of Advanced Cladding and Structural Material (M5) in PWR Reactor Fuel", NRC SER dated February 4, 2000.

6.9.5.3 The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient/accident analysis limits) of the safety analysis are met.

6.9.5.4 The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance for each reload cycle to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

6.9.6 STEAM GENERATOR TUBE INSPECTION REPORT

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6.9.6 STEAM GENERATOR TUBE INSPECTION REPORT

A report shall be submitted within 90 days after the average reactor coolant temperature exceeds 200°F following completion of an inspection performed in accordance with Section 6.19, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing,

h. The effective plugging percentage for all plugging and tube repairs in each SG,

i. Repair method utilized and the number of tubes repaired by each repair method, if any,

j. Location, bobbin coil depth estimate (if determined), bobbin coil amplitude (if determined), and axial and circumferential extent for each inside diameter (ID) IGA indication.

k. An assessment of growth of inside diameter IGA degradation in accordance with the volumetric ID IGA management program contained in AmerGen Engineering Report, ECR No. TM 01-00328.

l. The information specified for reporting in ECR No. 02-01121, Rev.2.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   1. A change in the TS incorporated in the license or

   2. A change to the updated FSAR (UFSAR) or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that meet the criteria of Specification 6.18.b.1 or 6.18.b.2 above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71 (e).

6.19 STEAM GENERATOR (SG) PROGRAM

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6.19 STEAM GENERATOR (SG) PROGRAM

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

   2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. <u>Leakage is not to exceed 1 gpm per SG, except for specific types of degradation at specific locations as described in paragraph c of the Steam Generator Program below</u>.

   3. The operational leakage performance criterion is specified in TS 3.1.6, "LEAKAGE."

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following alternate tube repair criteria may be applied as an alternative to the 40% depth based criteria:

   a. Volumetric Inside Diameter (ID) Inter-Granular Attack (IGA) indications may be dispositioned in accordance with ECR No. TM 01-00328. MSLB accident-induced leakage rates are limited to less than 1 gpm under the report. (ECR No. TM 01-00328 is not applicable to tube sleeves nor the parent tubing spanned by the sleeves.) ID IGA indications shall be repaired or removed from service if they exceed an axial extent of 0.25 inches, or a circumferential extent of 0.52 inches, or a through wall degradation dimension of ≥ 40% if assigned.

   b. Upper tubesheet kinetic expansion indications may be dispositioned in accordance with ECR No. TM 02-01121, Rev. 2. MSLB accident-induced leakage is limited to less than 3228 gallons for the initial 2 hours, and 9960 gallons over the MSLB duration, under this report.

2. Tubes found by inservice inspection to contain a flaw in a sleeve, or in a sleeve's parent tube adjacent to the sleeve between the lower sleeve end and the parent tube kinetic expansion transition, shall be "plugged-on-detection" in accordance with ECR No. TM 02-01121, Rev. 2.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, d.3, d.4, and d.5 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

4. Implementation of the repair criteria for ID IGA requires 100% bobbin coil inspection of all non-plugged tubes in accordance with AmerGen Engineering Report, ECR No. TM 01-00328. ID IGA indications detected by the bobbin coil probe shall be characterized using rotating coil probes, as defined in that report.

5. Implementation of the repair criteria for kinetic expansion indications requires 100% rotating probe inspection of the required lengths of the kinetic expansions in all non-plugged, non-sleeved, tubes in accordance with AmerGen Engineering Report, ECR No. TM 02-01121, Rev.2.

6. During each scheduled refueling outage steam generator inspection, the following sleeve examinations shall be conducted:
   -a minimum of 33% of the inservice sleeves' unexpanded lengths shall be examined with bobbin coil probes.
   - a minimum of 33% of the inservice sleeves' upper tubesheet roll expansions, and 100% of the inservice sleeves lower roll expansions, shall be examined with PlusPoint probes.

e. Provisions for monitoring operational primary to secondary leakage.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.

TMI-1's 80" Inconel-690 rolled sleeves installed in 1991 and 1993, and without flaws exceeding the repair criteria of 6.19.c.2, may remain in service. Installation of new sleeves or other new repair methods requires prior NRC approval.

NOTE: Refer to Section 6.9.6 for reporting requirements for periodic SG tube inspections.