Committed to Nuclear Excellence

Nuclear Management Company, LLC

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Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

Supplement to Application For Technical Specification Improvement Regarding Steam Generator Tube Integrity

Reference 1) License Amendment Request (LAR) titled, "Application For Technical Specification Improvement Regarding Steam Generator Tube Integrity", dated February 16, 2006

By letter dated February 16, 2006, Nuclear Management Company (NMC) submitted the referenced LAR to adopt Technical Specification (TS) improvements regarding steam generator tube integrity provided in Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler TSTF-449, "Steam Generator Tube Integrity", Revision 4. This letter supplements the referenced LAR to address the Nuclear Regulatory Commission (NRC) Staff requests for additional information (RAIs) regarding Enclosures 4C and 5C which apply to the Prairie Island Nuclear Generating Plant, Units 1 and 2 (PINGP). NMC is submitting this supplement in accordance with the provisions of 10 CFR 50.90.

Enclosure 1 provides the NRC RAIs and NMC responses. Enclosure 2, which includes the TS and Bases pages marked up in response to the RAIs, replaces Enclosure 4C of the Reference LAR in its entirety. The proposed TS and Bases additions in the original submittal (Reference 1) were shown with double-underline and the deletions were shown with strikethrough. Further proposed TS and Bases additions in response to RAIs in this supplement are shown as bold and the deletions are shown with shaded-strikethrough. The proposed changes associated with this supplement appear on pages 5.0-14, 5.0-20, 5.0-21, 5.0-22, 5.0-24, 5.0-25, 5.0-26, 5.0-27, 5.0-28, 5.0-40, B 3.4.14-2, B 3.4.14-3, B 3.4.14-4, B 3.4.19-2 and B 3.4.19-3. Enclosure 3, which includes the TS and Bases pages revised in response to the RAIs, replaces Enclosure 5C of the Reference LAR in its entirely.

The additional information provided in this supplement does not impact the conclusions of the Determination of No Significant Hazards Consideration and Environmental Assessment presented in the referenced February 16, 2006 submittal.

In accordance with 10 CFR 50.91, NMC is providing a copy of this letter and enclosures to the designated State Official.

Summary of Commitments

This letter contains no new commitments and no revisions to existing commitments.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on **21 July 2006**.

Edward J. Weinkam
Director, Nuclear Licensing and Regulatory Services
Nuclear Management Company, LLC

Enclosures (3)

cc: Administrator, Region III, USNRC
Project Manager, Prairie Island Nuclear Generating Plant, USNRC
Senior Resident Inspector, Prairie Island Nuclear Generating Plant, USNRC
State Official, Minnesota Department of Commerce

Enclosure 1

Nuclear Regulatory Commission Requests for Additional Information and Nuclear Management Company Responses

Question 1. Proposed Technical Specification (TS) 5.5.8.b.2 describe the accident induced leak rate limits for Prairie Island 1 and 2. For Unit 2, there is an exception allowed to the 1 gallon per minute (gpm) limit based on implementation of the voltage-based repair criteria; however, as currently proposed it appears that this limit could be inappropriately applied to Unit 1. In addition, the proposed Unit 2 limit appears to allow leakage from sources other than from degradation left in service with the voltage-based tube repair criteria to exceed 1 gpm. Please discuss your plans to modify your proposal to clearly indicate that the accident induced leakage limit for Unit 1 is 1 gpm (regardless of whether Unit 2 is implementing the voltage-based repair criteria). In addition, please discuss your plans to specify that for Unit 2, the leakage from all sources excluding the leakage attributed to the degradation associated with implementation of the voltage-based alternate repair criteria will not exceed 1 gpm per steam generator (SG).

For example: "For Unit 1 leakage is not to exceed 1 gpm per SG. For Unit 2, leakage from all sources, excluding the leakage attributed to the degradation described in TS Section [insert appropriate Section] is not to exceed 1 gpm per SG."

The staff notes that reference to the 1.42 gpm limit in your current proposal should not be needed since this should be consistent with your current accident analysis (which is addressed by the first sentence in your proposed accident induced leakage performance criterion). The staff also notes that your Bases may also need to be revised to clarify this issue (page B3.4.19-2).

Question 1, Nuclear Management Company (NMC) response:

NMC has incorporated the Nuclear Regulatory Commission (NRC) example wording in proposed Technical Specification (TS) 5.5.8.b.2 as shown in Enclosures 2 and 3 and deleted the last two sentences. The resulting “Accident induced leakage performance criterion” now reads (added text shown as bold, deleted text not shown):

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. **For Unit 1,** leakage is not to exceed 1 gpm per SG. **For Unit 2, leakage from all sources, excluding the leakage attributed to the degradation associated with**

implementation of the voltage-based repair criteria, is not to exceed 1 gpm per SG.

The last paragraph of proposed Bases page B 3.4.19-2 has been revised as shown in Enclosures 2 and 3, and now reads (added text shown as bold, deleted text not shown) as follows:

> The analys**e**s 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 of **1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analyses assume the leakage from the faulted SG is limited to** 1.42 gallons per minute (based on a reactor coolant system temperature of 578 ºF.)

Question 2. Per your proposed structural integrity performance criterion, a safety factor of 1.4 against burst will be applied to the design basis accident primary to secondary pressure differentials. However, Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," indicated that there is a possibility that a tube may have a burst pressure less than 1.4 times the steam line break pressure differential (given the uncertainties associated with the various correlations); therefore, the GL 95-05 alternate repair criteria (ARC) imposed a limit on the probability of burst (POB) of $1x10^{-2}$. As a result, it is not clear from your submittal that the structural integrity performance criterion is complete since it does not fully address all the performance criteria for implementation of the voltage-based ARC. Please discuss your plans to modify the performance criteria to fully address the voltage-based ARC. For example, discuss your plans for modifying the structural integrity performance criteria to indicate that for predominantly axially oriented outside diameter stress corrosion cracking at the tube support plate elevations the POB of one or more indications given a steam line break shall be less than $1x10^{-2}$. Upon incorporation of this criterion into the structural integrity performance criterion, please discuss your plans to eliminate the associated reporting requirement in proposed TS 5.6.7.b.5 since operation in excess of this limit will not be permitted.

Question 2, NMC response:

NMC proposes to revise TS 5.5.8.b.1 by the addition of the following text which will acknowledge the voltage-based criteria additional structural integrity performance criterion (added text shown as bold, no text deleted):

For Unit 2, when tubes are left in service with predominantly axially oriented stress corrosion cracking at the tube support plate elevations, the probability of burst under main steam line break conditions shall be maintained below 1E-02 in accordance with the requirements of NRC Generic Letter (GL) 95-05.

NMC does not propose to remove the reporting requirements previously proposed as TS 5.6.7.b.5 (in accordance with the response to Question 7 below, these are now proposed as TS 5.6.7.b.4) because they are included in the current Prairie Island Nuclear Generating Plant (PINGP) TS paragraph 5.6.7.5.e and, thus, removing these reporting requirements would change the current licensing basis for use of the voltage based repair criteria.

Question 3. In your proposed TS (and Technical Specification Task Force-449), 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. Given this definition and the possibility that sleeves can extend to near the tube-end, the proposed repair criteria in TS 5.5.8.c.2 may not be complete. In addition, the staff notes the following concerning your proposed tube repair criteria: (1) it is not clear that your proposed TS contains the appropriate repair limit for the parent tube at the locations of the sleeve-to-tube joint, (2) it is not clear whether the F*/EF* criteria could be applied in the cold-leg, (3) it is not clear whether the EF* and the F* criteria must be satisfied below the mid-plane of the tubesheet, (4) there is redundancy regarding the use of the phrase "predominately axially oriented outside diameter stress corrosion cracking" in proposed TS 5.5.8.c.2(c), and (5) it is not clear that indications between 2.0 volts and the upper voltage repair limit may remain in service if no degradation is detected with a rotating pancake coil (or equivalent). Please discuss your plans to modify your TS to address these issues.

For example, the TS may be modified by using something similar to the following:

For Unit 2, the non-sleeved region of a tube found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged or repaired except if the flaws are permitted to remain in service through application of an alternate tube repair criteria discussed below. Tubes shall be plugged if the sleeved region of a tube is found by inservice inspection to contain flaws in the (a) sleeve or (b) the pressure boundary portion of the original tube wall in the sleeve/tube assembly (i.e., the sleeve-to-tube joint).

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

a. Localized wall thinning in non-sleeved regions of the tube: For these areas, tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 50% of the nominal wall thickness shall be plugged or repaired.

b. F*/EF* criteria: For the non-sleeved regions of the tube in the hot-leg tubesheet, the plugging or repair limit is as follows:

If the bottom of the uppermost hardroll transition in the tubesheet is below the midplane of the tubesheet, then all defects located below 1.07-inches from the bottom of this uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.07-inch span (not including eddy current uncertainty). This 1.07-inch span (not including eddy current uncertainty) is referred to as the F* region. If flaws are contained within the F* region, the tube shall be plugged or repaired.

If the bottom of the uppermost hardroll transition in the tubesheet is above the midplane of the tubesheet but at least 2.0 inches below the top of the secondary face of the tubesheet, then all defects located below 1.67-inches from the bottom of the uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.67-inch span (not including eddy current uncertainty). This 1.67-inch span (not including eddy current uncertainty) is referred to as the EF* region. If flaws are contained within the EF* region, the tube shall be plugged or repaired.

c. Tube support plate voltage-based repair criteria: For non-sleeved regions of the tube affected by predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates, the plugging or repair limit is as follows:

If the bobbin voltage associated with the degradation is less than or equal to 2.0 volts, the degradation is allowed to remain in service.

If the bobbin voltage associated with the degradation is greater than 2.0 volts, the tube shall be plugged or repaired unless the voltage is less than or equal to the upper voltage repair limit (calculated according to the methodology in Generic Letter 95-05 as supplemented) and a rotating pancake coil (or comparable examination technique) does not detect the flaw. In this latter case, the flaw may remain in service.

If an unscheduled mid-cycle inspection is performed, [insert appropriate wording from currently approved TS]

Question 3, NMC response:

(1) As shown in Enclosures 2 and 3, TS 5.5.8.c.2(a)(2), the sleeve repair criteria is revised to include specific wording for the sleeve-to tube joint.

(2) The F* and EF* criteria are based on the limiting case of the cold leg thermal growth mismatch as described in WCAP-14225, "F* and Elevated F* Tube Plugging Criteria for Tubes with Degradation in the Tubesheet Region of the Prairie Island Units 1 and 2 Steam Generators", Revision 2, which was submitted with the license amendment request (LAR) titled, "Revision to Elevated F* Steam Generator Tube Repair Criteria", dated November 10, 1999 (Accession No. ML993230226) and was approved by the NRC for application to PINGP in License Amendments 149 and 140, Units 1 and 2 respectively, issued on April 19, 2000.

The F* and EF* criteria are also applicable to the cold leg as shown in WCAP-14225 which states on page 3-2, "As with F*, EF* is calculated for the cold leg, where the thermal growth mismatch is also minimized. Therefore, the calculated values of EF* are conservative for application to the hot leg, where it will primarily be applied."

(3) The repair criteria for F* and EF* are placed in a new proposed TS 5.5.8.c.2(b) and reworded as follows (added text shown as bold, deleted text not shown):

(1) F* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is below the midplane of the tubesheet, then all defects located below 1.07 inches from the bottom of this uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.07-inch span (not including eddy current uncertainty). This 1.07-inch span (not including eddy current uncertainty) is referred to as the F* region. If flaws are contained within the F* region, the tube shall be plugged or repaired.

(2) EF* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is above the midplane of the tubesheet but at least 2.0 inches below the top of the secondary face of the tubesheet, then all defects located below 1.67 inches from the bottom of the uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.67-inch span (not including eddy current uncertainty). This 1.67-inch span (not including eddy current uncertainty) is referred to as the EF* region. If flaws are contained within the EF* region, the tube shall be plugged or repaired.

(4) Proposed TS 5.5.8.c.2(c) has been revised to remove wording redundancy.

(5) Proposed TS 5.5.8.c.2(c) has been reworded as follows (added text shown as bold, deleted text not shown):

(c) **The following Alternate Tube Support Plate Voltage-Based Repair Criteria may be applied as an alternative to the depth based criteria: For regions of the tube affected by** predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates **the plugging or repair limit is as follows:**

(1) If the bobbin voltage associated with the degradation is less than or equal to 2.0 Volts, the degradation is allowed to remain in service.
(2) If the bobbin voltage associated with the degradation is greater than 2.0 Volts, the tube shall be plugged or repaired unless the voltage is less than or equal to the upper voltage repair limit (calculated according to the methodology in GL 95-05 as supplemented) and a rotating pancake coil (or comparable examination technique) does not detect the flaw. In this latter case, the flaw may remain in service.

Question 4. In your proposed inspection requirements for Unit 2, please address the following:

Question 4a. You proposed that each time a SG is inspected that all tubes within that SG which have had the F*/EF* criteria applied will be inspected. If it is not your intent to inspect these tubes under all circumstances in which a SG may be inspected (e.g., a primary-to-secondary leak in the middle of a cycle), please clarify your intent. For example, the F* and EF* region of the tube shall be inspected every 24 effective full power months or one refueling outage (whichever is less) if flaws were allowed to remain in service in these tubes by using the F*/EF* criteria.

Question 4a, NMC response:

Proposed TS 5.5.8.d.3(a) has been rewritten as follows such that F*and EF* inspections are required only during scheduled refueling cycle inspections (added text shown as bold, deleted text not shown):

(a) During each Unit 2 SG refueling outage inspection, all tubes within that SG which have had the F* or EF* criteria applied will be inspected in the F* and EF* regions of the roll expanded region. The region of these tubes below the F* and EF* regions may be excluded from the inspection requirements.

Question 4b. Your current proposal uses terms such as F* criteria and F* region without defining them. The staff notes that incorporation of the suggestions above may address this issue.

Question 4b, NMC response:

Proposed TS 5.5.8.c.2(b) has been revised to incorporate definitions as shown in the response to Question 3 above.

Question 4c. You proposed to exclude from inspection the region of the tube below the F* and EF* regions. Since sleeves may be installed below the F* and EF* regions, please discuss your plans to modify your proposal to ensure any such sleeves will be required to be inspected. The staff notes that incorporation of the suggestions above may address this issue.

Question 4c, NMC response:

The PINGP tubes approved for use within the tubesheet are Full Depth Tubesheet (FDTS) sleeves, thus, it is not possible to have a sleeve installed below an F* or EF* region at PINGP. As described in the PINGP LAR, "Incorporation of Combustion Engineering Steam Generator Welded Tube Sleeve Topical Report", dated November 27, 1996, "The sleeve welds are autogenous welds between the sleeve and parent tube. Sleeve welds are located in the free span of tubing above the tubesheet or outside of the tube support plates or at the lower end of the tube." This requires the top end of the tubesheet sleeve to be above the top of the tubesheet. The November 27, 1996 LAR continues with a description of the sleeves as follows:

> Three types of sleeves are available for installation – two types of tubesheet region sleeves and one type of tube support sleeve. The first two types of sleeves are Full Depth Tubesheet (FDTS) Sleeves which span the tubesheet region. Both types of FDTS sleeves have an upper welded joint located above the tubesheet. The first type has a lower joint formed by welding the lower end of the sleeve to the lower end of the parent tube. The second type of tubesheet sleeve has a lower joint formed by hard rolling the sleeve into the parent tube in the region of the original hard roll.

Question 4d. In your current TS, there are requirements to perform inspections of intersections to which the voltage-based repair criteria apply (i.e., 5.5.8.b.5 and 5.5.8.b.6). Please describe the technical basis for deleting these requirements or alternatively propose to include similar requirements in your current amendment request.

Question 4d, NMC response:

The requirements of current TS 5.5.8.b.5 and 5.5.8.b.6 should have been included in the proposed TS. The inspection requirements for the voltage based repair criteria have been added to 5.5.8.d.3 as new paragraphs (b) and (c) as follows (added text shown as bold, no text deleted):

(b) Implementation of the SG tube and tube support plate repair criteria require a 100 percent bobbin coil inspection for hot leg and cold leg tube support plate intersections down to the lowest cold leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

(c) SG tube indications left in service as a result of application of tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.

Question 5. Proposed TS 5.5.8.f.2 on tube repair methods for Unit 2 is not clear and appears to have more detail than is needed. Please discuss your plans to clarify and simplify your proposed specification. For example:

For Unit 2, the following are approved repair methods:

a. Alloy 690 tungsten inert gas welded sleeves in accordance with CEN-629-P, Revision 03-P, "Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves."

b. Hardroll expanding portions of non-sleeved tubes in the hot-leg tubesheet in order to apply the F*/EF* criteria.

Question 5, NMC response:

Proposed TS 5.5.8.f.2 has been revised as follows (added text shown as bold, deleted text not shown):

2. **For Unit 2, the following are approved repair methods:**

   (a) **Alloy 690 tungsten inert gas welded sleeves** in accordance with CEN-629-P, Revision 03-P, "Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves."

   (b) **Hardroll expanding portions of tubes in the tubesheet in order to apply the F* and EF* criteria.**

Question 6. Confirm that as part of your proposed reporting requirement in TS 5.6.7.a.4 (location, orientation, and measured sizes of service induced indications) that you will identify tubes in which flaws were allowed to remain in service using the F*/EF* criteria (consistent with your current TS

requirement). Similarly confirm that as part of your proposed reporting requirement in TS 5.6.7.a.9 that you intend to provide the number of tubes repaired by installing additional hardroll expansions and the cumulative number of tubes currently in service repaired by this method.

Question 6, NMC response:

Current TS 5.6.7.4 requires reporting of tubes in which flaws were allowed to remain in service using the F* and EF* criteria. A new proposed TS 5.6.7.a.10 is added to be consistent with the current TS 5.6.7.4 reporting requirements for F* and EF* tubes. The reporting date is changed from 15 days following the inspection to 180 days after initial entry into Mode 4 in accordance with the requirements of proposed TS 5.6.7.a. This report is in addition to the report required by proposed TS 5.6.7.a.4.

Since installing additional rerolls is a repair method described in proposed TS 5.5.8.f, the number of tubes repaired by installing additional reroll expansions are required to be included in the report for T.S. 5.6.7.a.9. The cumulative number of tubes currently in service repaired by rerolls is the total number of tubes reported per TS 5.6.7.a.10.

The new proposed paragraph TS 5.6.7.a.10 reads as follows (added text shown as bold, no text deleted):

10. **The results of inspections performed under Specification 5.5.8.d.3(a) for all tubes that have defects below the F* or EF* distance, and were not plugged. The report shall include: a) identification of F* and EF* tubes; and b) location and extent of degradation.**

Question 7. Given that your proposed TS do not allow operation when the accident induced leakage criteria is exceeded, please discuss your plans to omit TS Section 5.6.7.b.1.

Question 7, NMC response:

The reporting requirement previously proposed in TS 5.6.7.b.1 has been deleted and the subsequent reporting requirements renumbered as shown in Enclosures 2 and 3.

Question 8. One of the purposes of TSTF-449 is to allow licensees to update their TSs to accurately reflect their SG tube integrity program. For implementation of the voltage-based tube repair criteria, licensees have submitted "90-day reports" providing information concerning tube pulls and condition monitoring/operational assessment results. Consistent with the philosophy of TSTF-449, please discuss your plans to modify TS Section 5.6.7, SG Tube Inspection Report, to include a requirement to provide the information

described in Section 6b of Attachment 1 of GL 95-05 to the U.S. Nuclear Regulatory Commission.

Question 8, NMC response:

The reporting guidance provided in Section 6b of Attachment 1 of GL 95-05 is not included in the current PINGP TS and is not part of Technical Specification Task Force (TSTF) industry traveler TSTF-449, “Steam Generator Tube Integrity”, Revision 4, on which this LAR is based.

TSTF-449, 4.0 Technical Analysis, Section 13, “Reporting Requirements”, page 17 of 25, states:

> The proposed reporting requirements are an improvement as compared to those required by the current technical specifications. The proposed reporting requirements are more useful in identifying the degradation mechanisms and determining their effects. In the unlikely event that a performance criterion is not met, NEI 97-06 (Ref. 1) directs the licensee to submit additional information on the root cause of the condition and the basis for the next operating cycle.
>
> The changes to the reporting requirements are performance based. The new requirements remove the burden of unnecessary reports from both the NRC and the licensee, while ensuring that critical information related to problems and significant tube degradation is reported more completely and, when required, more expeditiously than under the current technical specifications.

The TSTF-449 Technical Analysis discussion, on page 19 of 25, concludes:

> The proposed changes will provide greater assurance of SG tube integrity than that offered by the current technical specifications. The proposed requirements are performance based and provide the flexibility to adopt new technology as it matures. These changes are consistent with the guidance in NEI 97-06, “Steam Generator Program Guidelines,” (Ref. 1).

Consistent with the performance based philosophy of TSTF-449 and the guidance of Nuclear Energy Institute (NEI) 97-06, NMC does not propose to incorporate the reporting guidance provided in Section 6b of Attachment 1 of GL 95-05 in TS 5.6.7.

Question 9. On page B 3.4.14-2 of your Bases, you indicate (in two places) that the accident induced leakage limit is 1 gpm; however, proposed TS 5.5.8.b.2 implies that this limit is 1.42 gpm for Unit 2. Please clarify this discrepancy.

Question 9, NMC response:

The Bases B 3.4.14 loss of coolant accident (LOCA) discussion at the top of page B 3.4.14-2 was revised as shown in Enclosure 2 and reads as follows (added text shown as bold, deleted text not shown):

> The safety analysis for an event resulting in steam discharge to the atmosphere assumes **the total primary to secondary LEAKAGE is 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analysis assumes the leakage from the faulted SG is limited to 1.42 gallons per minute (based on a reactor coolant system temperature of 578 ºF).**

Likewise the Bases B 3.4.14 steam line break (SLB) discussion at the bottom of page B 3.4.14-2 and top of page B 3.4.14-3 was revised as shown in Enclosure 2 and reads as follows (added text shown as bold, deleted text not shown):

> The safety analysis for the SLB accident assumes **the total primary to secondary LEAKAGE is 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analysis assumes the leakage for this repair method will be limited to 1.42 gallons per minute (based on a reactor coolant system temperature of 578 ºF).**

Question 10. On page B3.4.14-4, you indicate that the 150 gallon per day (gpd) limit is based on implementation of the voltage based tube repair criteria. Although the 150 gpd limit may have been adopted when the voltage based tube repair criteria was implemented, it is not the basis for the requirement. Please discuss your plans to modify your TS Bases to remove this discussion.

Question 10, NMC response:

Wording for Bases B 3.4.14, Limiting Condition for Operation (LCO), Section d. on Page B 3.4.14-4, has been revised to the TSTF-449 wording as shown in Enclosure 2.

Question 11. On page B 3.4.19-3, you indicate that the region of tube below the F* and EF* distances are not part of the tube. Please discuss your plans to clarify this statement in light of questions 3 and 4 above including your plans to clarify that this is only applicable to non-sleeved tubes.

Question 11, NMC response:

As discussed in response to Question 4c above, the current authorized tubesheet sleeve can not be installed below an F*or EF* region, thus, no clarification is necessary.

ENCLOSURE 2

Proposed Technical Specification and Bases Pages (markup)

Prairie Island Nuclear Generating Plant Units 1 and 2

Technical Specification Pages

1.1-3	5.0-22
3.4.14-2	5.0-23
3.4.14-3	5.0-24
3.4.19-1	5.0-25
3.4.19-2	5.0-26
5.0-13	5.0-27
5.0-14	5.0-28
5.0-15	5.0-36
5.0-16	5.0-37
5.0-17	5.0-38
5.0-18	5.0-39
5.0-19	5.0-40
5.0-20	5.0-41
5.0-21	

Bases pages

B 3.4.4-2	B 3.4.19-2
B 3.4.14-2	B 3.4.19-3
B 3.4.14-3	B 3.4.19-4
B 3.4.14-4	B 3.4.19-5
B 3.4.14-5	B 3.4.19-6
B 3.4.14-6	B 3.4.19-7
B 3.4.14-7	B 3.4.19-8
B 3.4.14-8	B 3.4.19-9
B 3.4.14-9	B 3.4.19-10
B 3.4.19-1	

46 pages follow

1.1 Definitions (continued)

$\bar{E}$ -AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 15 minutes, making up at least 95% of the total noniodine activity in the coolant.
LEAKAGE	LEAKAGE from the Reactor Coolant System (RCS) shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. RCS LEAKAGE through a steam generator ~~(SG)~~ to the Secondary System (primary to secondary LEAKAGE);

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary ~~SG~~ LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS identified LEAKAGE not within limit for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	C.1 Be in MODE 3. AND C.2.1 Reduce LEAKAGE to within limits. OR C.2.2 Be in MODE 5.	6 hours 14 hours 44 hours
D. Pressure boundary LEAKAGE exists. OR Primary to secondary ~~SG~~ LEAKAGE not within limit.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.14.1	---------------------------NOTES------------------------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. --- Verify RCS operational LEAKAGE~~leakage~~ within limits by performance of RCS water inventory balance.	24 hours
SR 3.4.14.2	---------------------------NOTE-------------------------- Not required to be performed until 12 hours after establishment of steady state operation. --- Verify ~~steam generator tube integrity is in accordance with the Steam Generator Program~~primary to secondary LEAKAGE is < 150 gallons per day through any one SG..	~~In accordance with the Steam Generator Program~~ 72 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.19 Steam Generator (SG) Tube Integrity

LCO 3.4.19 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged or repaired in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged or repaired in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug or repair the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.19.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.19.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged or repaired in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Programs and Manuals (continued)

5.5.8 Steam Generator (SG) ~~Tube Surveillance~~ 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 or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired 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. **For Unit 2, when tubes are left in service with predominantly axially oriented stress corrosion cracking at the tube support plate elevations, the probability of burst under main steam line break conditions shall be maintained below 1E-02 in accordance with the requirements of NRC Generic Letter (GL) 95-05**.

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. **For Unit 1,** leakage is not to exceed 1 gpm per SG. **For Unit 2, leakage from all sources, excluding the leakage attributed to the degradation associated with implementation of the voltage-based repair criteria, is not to exceed 1 gpm per SG.** ~~, except during the implementation of steam generator repairs on Unit 2 utilizing the voltage-based repair criteria. During the implementation of steam generator repairs on Unit 2 utilizing the voltage-based repair criteria, the total calculated primary to secondary side leakage from the faulted steam generator, under main steam line break conditions (outside containment and upstream of the main steam isolation valves), will not exceed 1.42 gallons per minute (based on a reactor coolant system temperature of 578°F).~~

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.14, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria:

1. Unit 1 steam generator 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.

2 Unit 2 steam generator tubes that meet the following criteria shall be plugged or repaired.

(a) Depth Based Criteria:

~~Steam generator tubes in each unit shall be determined OPERABLE by the following:~~

~~a. Steam Generator Sample Selection and Inspection~~

~~Each steam generator shall be determined OPERABLE in accordance with the in-service inspection schedule in Specification 5.5.8.c. The in-service inspection may be limited to one steam generator on a rotating schedule encompassing 6% of the tubes in the single steam generator, provided the previous inspections indicated that the two steam generators are performing in a like manner.~~

~~b. 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 Tables 5.5.8-1 and 5.5.8-2. The in-service inspection of steam generator tubes shall be performed at the Frequencies specified in Specification 5.5.8.c and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.8.d. The tubes selected for each in-service inspection shall include at least 3% of the total number of tubes in all steam generators and at least 20% of the total number of sleeves in service in both steam generators; the tubes selected for these inspections shall be selected on a random basis except:~~

~~1. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.~~

~~2. The first sample of tubes selected for each in-service inspection (subsequent to the preservice inspection) of each steam generator shall include:~~

~~(a) all tubes that previously had detectable wall penetrations (> 20%) that have not been plugged or sleeve repaired in the affected area.~~

~~(b) tubes in those areas where experience has indicated potential problems.~~

~~(c) a tube inspection (pursuant to Specification 5.5.8.d.1.(h)) 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.~~

~~3. In addition to the sample required in Specification 5.5.8.b.2(a) through (c), all tubes which have had the F* or EF* criteria applied will be inspected in the F* and EF* regions of the roll expanded region. The region of these tubes below the F* and EF* regions may be excluded from the requirements of Specification 5.5.8.b.2(a).~~

~~4. The tubes selected as the second and third samples (if required by Tables 5.5.8-1 or 5.5.8-2) during each in-service inspection may be subjected to a partial tube or sleeve inspection provided:~~

~~(a) the tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.~~

~~(b) the inspections include those portions of the tubes or sleeves where imperfections were previously found.~~

~~5.5 Programs and Manuals~~

~~5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)~~

~~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 are degraded tubes and none of the inspected tubes are defective.~~
~~C-2~~	~~One or more tubes, but not more than 1% of the total tubes inspected 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 are degraded tubes or more than 1% of the inspected tubes are defective.~~

~~Note: In all inspections, previously degraded tubes must exhibit significant (> 10%) further wall penetrations to be included in the above percentage calculations.~~

~~5. Indications left in service as a result of application of tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.~~

~~6. Implementation of the steam generator tube/tube support plate repair criteria requires a 100 percent bobbin coil inspection for hot leg and cold leg tube support plate intersections down to the lowest cold leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.~~

~~5.5 Programs and Manuals~~

~~5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)~~

~~c. Inspection Frequencies~~

~~The above required in-service inspections of steam generator tubes shall be performed at the following Frequencies:~~

~~1. In-service inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.~~

~~2. If the results of the in-service inspection of a steam generator conducted in accordance with Table 5.5.8-1 at 40 month intervals fall in Category C-3, the inspection frequency 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 5.5.8.c.1; the interval may then be extended to a maximum of once per 40 months.~~

~~3. Additional, unscheduled in-service inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 5.5.8-1 during the shutdown subsequent to any of the following conditions:~~

~~(a) primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.14.~~

~~(b) a seismic occurrence greater than the Operating Basis Earthquake.~~

~~5.5 Programs and Manuals~~

~~5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)~~

~~(c) a loss-of-coolant accident requiring actuation of the engineered safeguards.~~

~~(d) a main steam line or feedwater line break.~~

~~d. Acceptance Criteria~~

~~1. As used in this Specification:~~

~~(a) Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections.~~

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

~~(c) Degraded Tube means a tube containing imperfections ≥ 20% of the nominal wall thickness caused by degradation.~~

~~(d) % Degradation means the percentage of the tube wall thickness affected or removed by degradation.~~

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

~~5.5 Programs and Manuals~~

~~5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)~~

~~(f) Repair Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging or repaired by sleeving because it may become unserviceable prior to the next inspection and is~~

(1~~(a~~) Tubes found by inservice inspection containing flaws with a depth equal to or exceeding 50% of the nominal tube wall thickness. If significant general tube thinning occurs, this ~~criteria will be~~criterion is reduced to 40% wall penetration. ~~This criterion does not apply to tube support plate intersections to which the voltage based repair criteria apply. This criterionThis definition does not apply to the portion of the tube in the tubesheet below the F* or EF* distance provided the tube is not degraded (i.e., no indications of cracks) within the F* or EF* distance for F* or EF* tubes.~~

~~The F* distance is the distance from the bottom of the upper hardroll transition toward the bottom of the tubesheet that has been conservatively determined to be 1.07 inches (not including eddy current uncertainty). The F* distance applies to roll expanded regions below the midplane of the tubesheet.~~

~~The EF* distance is the distance from the bottom of the upper hardroll transition toward the bottom of the tubesheet that has been conservatively determined to be 1.67 inches (not including eddy current uncertainty). The EF* distance applies to roll expanded regions when the top of the additional roll expansion is 2.0 inches or greater down from the top of the tubesheet.~~

(2~~(b~~) Tubes found by inservice inspection containing flaws in~~The repair limit for~~ the pressure boundary region of any**: 1)** sleeve**; or 2) pressure boundary portion of the original tube wall in the sleeve-to-tube joint** with a depth equal to or exceeding~~is~~ 25% of the nominal sleeve wall thickness. ~~This~~

~~definition does not apply to tube support plate intersections for which the voltage-based repair criteria are being applied. Refer to Specification 5.5.8.d.4 for the repair limit applicable to these intersections.~~

(b) **The following F* or EF* Alternate Repair Criteria may be applied as an alternative to the depth based criteria: Flaws may be left in service when they are located below F* or EF* defined below:**

(1) **F* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is below the midplane of the tubesheet, then all defects located below 1.07 inches from the bottom of this uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.07-inch span (not including eddy current uncertainty). This 1.07-inch span (not including eddy current uncertainty) is referred to as the F* region. If flaws are contained within the F* region, the tube shall be plugged or repaired.**

(2) **EF* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is above the midplane of the tubesheet but at least 2.0 inches below the top of the secondary face of the tubesheet, then all defects located below 1.67 inches from the bottom of the uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.67-inch span (not including eddy current uncertainty). This 1.67-inch span (not including eddy current uncertainty) is referred to as the EF* region. If flaws are contained within the EF* region, the tube shall be plugged or repaired.**

(c) **The following Alternate Tube Support Plate Voltage-Based Repair Criteria may be applied as an alternative to the depth based criteria: For regions of the tube affected by** ~~Tubes found by inservice inspection that are experiencing~~ predominately axially oriented outside diameter stress

corrosion cracking confined within the thickness of tube support plates **the plugging or repair limit is as follows**:

(1) If the bobbin voltage associated with the degradation is less than or equal to 2.0 Volts, the degradation is allowed to remain in service.

(2) If the bobbin voltage associated with the degradation is greater than 2.0 Volts, the tube shall be plugged or repaired unless the voltage is less than or equal to the upper voltage repair limit (calculated according to the methodology in GL 95-05 as supplemented) and a rotating pancake coil (or comparable examination technique) does not detect the flaw. In this latter case, the flaw may remain in service.

(3) If an unscheduled mid-cycle inspection is performed,

~~(g) 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.~~

~~(h) Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.~~

~~(i) Sleeving is the repair of degraded tube regions using a new Alloy 690 tubing sleeve inserted inside the parent tube and sealed at each end by welding or by replacing the lower weld in a full depth tubesheet sleeve with a hard rolled joint. The new sleeve becomes the pressure boundary spanning the original degraded tube region.~~

~~(j) F* Distance is the distance from the bottom of the hardroll transition toward the bottom of the tubesheet that has been conservatively determined to be 1.07 inches (not including eddy current uncertainty). The F* distance applies to roll expanded regions below the midplane of the tubesheet.~~

~~(k) F* Tube is a tube with degradation, below the F* distance, equal to or greater than 40%, and not degraded (i.e., no indications of cracking) within the F* distance.~~

~~(l) EF* Distance is the distance from the bottom of the upper hardroll transition toward the bottom of the tubesheet that has been conservatively determined to be 1.67 inches (not including eddy current uncertainty). EF* distance applies to roll expanded regions when the top of the additional roll expansion is 2.0 inches or greater down from the top of the tubesheet.~~

~~(m) EF* Tube is a tube with degradation, below the EF* distance, equal to or greater than 40%, and not degraded (i.e., no indications of cracking) within the EF* distance.~~

~~2. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug or repair by sleeving all tubes exceeding the repair limit and all tubes containing through-wall cracks or classify as F* or EF* tubes) required by Tables 5.5.8-1 and 5.5.8-2.~~

~~3. Tube repair, after April 1, 1999, using Combustion Engineering welded sleeves shall be in accordance with the methods described in the following:~~

~~CEN-629-P, Revision 03-P, "Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves".~~

~~5.5 Programs and Manuals~~

~~5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)~~

~~4. Tube Support Plate Repair Limit is used for the disposition of a steam generator tube for continued service that is experiencing predominantly axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates. At tube support plate intersections, the repair limit is based on maintaining steam generator serviceability as described below:~~

~~(a) Steam generator tubes, whose degradation is attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with bobbin voltages less than or equal to 2.0 Volts will be allowed to remain in service.~~

~~(b) Steam generator tubes,~~

~~i whose with indications of potential degradation is attributed to predominately axially oriented outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than 2.0 Volts unless no degradation is detected with a rotating pancake coil (or comparable examination technique) inspection~~

~~, will be repaired or plugged, except as noted in Specification 5.5.8.d.4(c) below.~~

~~(c) Steam generator tubes, with indications of potential degradation attributed to outside diameter stress corrosion cracking within the bounds of the tube support plate with a bobbin voltage greater than 2.0 Volts but less than or equal to the upper voltage repair limit, may remain in service if a rotating pancake coil (or comparable examination technique) inspection does not detect degradation. Steam generator tubes,~~

~~ii with indications of predominately axially oriented outside diameter stress corrosion cracking degradation with a bobbin voltage greater than the upper voltage repair limit. will be plugged or repaired.~~

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) ~~Tube Surveillance~~ Program (continued)

(c)~~iii~~.**If** ~~(d) inspected duringIf~~ an unscheduled mid-cycle inspection **is performed** ~~is performed~~, the following mid-cycle repair limits apply instead of the limits in Specifications 5.5.8.c.2.(c)**(1)**.~~i~~~~d.4(a), (b)~~ and 5.5.8.c.2.(c)**(2)**.~~ii~~ above~~(c)~~. The mid-cycle repair limits are determined from the following equations:

$$V_{MURL} = \frac{V_{SL}}{1.0 + NDE + Gr\left(\frac{CL - \Delta t}{CL}\right)}$$

$$V_{MLRL} = V_{MURL} - (V_{URL} - 2.0)\left(\frac{CL - \Delta t}{CL}\right)$$

Where:

V_{URL} = upper voltage repair limit

V_{LRL} = lower voltage repair limit

V_{MURL} = mid-cycle upper voltage repair limit based on time into cycle

V_{MLRL} = mid-cycle lower voltage repair limit based on V_{MURL} and time into cycle

Δt = length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) ~~Tube Surveillance~~ Program (continued)

CL = cycle length (time between two scheduled steam generator inspections)

V_{SL} = structural limit voltage

Gr = average growth rate per cycle length

NDE = 95 percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by the NRC)

Implementation of these mid-cycle repair limits should follow the same approach as described in Specifications 5.5.8.c.2.(c)**(1)**~~.i~~ ~~d.4(a), (b)~~ and 5.5.8.c.2.(c)**(2)**~~.ii~~ above~~(c)~~.

Note: The upper voltage repair limit is calculated according to the methodology in ~~Generic Letter~~**GL** 95-05 as supplemented.

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 and d.4 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. For Unit 1 SGs, inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. For Unit 2 SGs, 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 more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

   (a). **During each Unit 2 SG refueling outage inspection**~~Each time a SG is inspected~~, all tubes within that SG which have had the F* or EF* criteria applied will be inspected in the F* and EF* regions of the roll expanded region. The region of these tubes below the F* and EF* regions may be excluded from the inspection requirements.

   (b). **Implementation of the SG tube and tube support plate repair criteria require a 100 percent bobbin coil inspection for hot leg and cold leg tube support plate intersections down to the lowest cold leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.**

   (c). **SG tube indications left in service as a result of application of tube support plate voltage-based repair**

criteria shall be inspected by bobbin coil probe during all future refueling outages.

4. 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.

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.

1. There are no approved SG tube repair methods for the Unit 1 SGs.

2. **For Unit 2, the following are approved repair methods:**

(a). **Alloy 690 tungsten inert gas welded sleeves**~~An approved SG tube repair method for the Unit 2 SGs is the use of welded sleeves~~ in accordance with ~~the methods described in~~CEN-629-P, Revision 03-P,"Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves".

(b). **Hardroll expanding portions of tubes in the tubesheet in order to apply the F* and EF* criteria.** ~~The installation of an additional hard roll expansion greater than the F* length and below the midplane of the tubesheet allows the use of F* criteria.~~

~~c. The installation of an additional hard roll expansion greater than the EF* length and anywhere below 2 inches from the top of the tubesheet allows the use of the EF* criteria.~~

~~Table 5.5.8-1~~
~~STEAM GENERATOR TUBE INSPECTION~~

~~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.~~	~~C-1~~	~~None~~	~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~
	~~C-2~~	~~Repair defective tubes and inspect additional 2S tubes in this S.G.~~	~~C-1~~	~~None~~	~~N/A~~	~~N/A~~
			~~C-2~~	~~Repair defective tubes and inspect additional 4S tubes in this S.G.~~	~~C-1~~	~~None~~
					~~C-2~~	~~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~~	~~N/A~~	~~N/A~~
	~~C-3~~	~~Inspect all tubes in this S.G., Repair defective tubes and inspect 2S tubes in each other S.G.~~	~~All other S.G.s are C-1~~	~~None~~	~~N/A~~	~~N/A~~
		~~Prompt notification to NRC~~	~~Some S.G.s C-2 but no additional S.G. are C-3~~	~~Perform action for C-2 result of second sample~~	~~N/A~~	~~N/A~~
			~~Additional S.G. is C-3~~	~~Inspect all tubes in each S.G. and repair defective tubes. Prompt notification to NRC.~~	~~N/A~~	~~N/A~~

~~S=3%; When two steam generators are inspected during that outage.~~
~~S=6%; When one steam generator is inspected during that outage.~~

~~Table 5.5.8-2~~
~~STEAM GENERATOR TUBE SLEEVE INSPECTION~~

~~1st Sample Inspection~~			~~2nd Sample Inspection~~	
~~Sample Size~~	~~Result~~	~~Action Required~~	~~Result~~	~~Action Required~~
~~A minimum of 20% of Tube Sleeves (1)~~	~~C-1~~	~~None~~	~~N/A~~	~~N/A~~
	~~C-2~~	~~Inspect all remaining tube sleeves in this S.G. and plug or repair defective sleeved tubes.~~	~~C-1~~	~~None~~
			~~C-2~~	~~Plug or repair defective sleeved tubes~~
			~~C-3~~	~~Perform action for C-3 result of first sample~~
	~~C-3~~	~~Inspect all tube sleeves in this S.G., inspect 20% of the tube sleeves in the other S.G., and plug or repair defective sleeved tubes~~	~~The other S.G. is C-1~~	~~None~~
			~~The other S.G. is C-2~~	~~Perform action for C-2 result of first sample~~
			~~The other S.G. is C-3~~	~~Inspect all tube sleeves in each S.G. and plug or repair defective sleeved tubes~~

~~(1) Each type of sleeve is considered a separate population for determination of scope expansion~~

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

b. The analytical methods used to determine the RCS pressure and temperature limits and Cold Overpressure Mitigation System setpoints shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves" (includes any exemption granted by NRC to ASME Code Case N-514).

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto. Changes to the curves, setpoints, or parameters in the PTLR resulting from new or additional analysis of beltline material properties shall be submitted to the NRC prior to issuance of an updated PTLR.

5.6.7 Steam Generator Tube Inspection Report

~~1. Following each in-service inspection of steam generator tubes, if there are any tubes requiring plugging or sleeving, the number of tubes plugged or sleeved in each steam generator shall be reported to the Commission within 15 days.~~

~~2.The results of steam generator tube in-service inspections shall be included with the summary reports of ASME Code Section XI inspections submitted within 90 days of the end of each refueling outage. Results of steam generator tube in-service inspections not associated with a refueling outage shall be submitted within 90 days of the completion of the inspection. These reports shall include: (1) number and extent of tubes inspected, (2) location and percent of wall thickness penetration for each indication of an imperfection, and (3) identification of tubes plugged or sleeved.~~

5.6 Reporting Requirements

5.6.7 Steam Generator Tube Inspection Report (continued)

~~3. Results of steam generator tube inspections which fall into Category C-3 require notification to the Commission prior to resumption of plant operation, and reporting as a special report to the Commission within 30 days. This special report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.~~

~~4. The results of inspections performed under Specification 5.5.8.b for all tubes that have defects below the F* or EF* distance, and were not plugged, shall be reported to the Commission within 15 days following the inspection. The report shall include:~~

~~a. Identification of F* and EF* tubes, and~~

~~b.Location and extent of degradation.~~

a. A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.8, Steam Generator (SG) Program. The report shall include:

1. The scope of inspections performed on each SG,

2. Active degradation mechanisms found,

3. Nondestructive examination techniques utilized for each degradation mechanism,

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

5. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,

6. Total number and percentage of tubes plugged or repaired to date,

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

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

9. Repair method utilized and the number of tubes repaired by each repair method~~.~~, **and**

10. The results of inspections performed under Specification 5.5.8.d.3(a) for all tubes that have defects below the F* or EF* distance, and were not plugged. The report shall include: a) identification of F* and EF* tubes; and b) location and extent of degradation.

b..~~5~~. For implementation of the voltage-based repair criteria to tube support plate intersections, notify the NRC staff prior to returning the steam generators to service should any of the following conditions arise:

~~1a. If estimated leakage based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds the leak limit (determined from the licensing basis dose calculation for the postulated main steamline break) for the next operating cycle,.~~

12~~b~~. If circumferential crack-like indications are detected at the tube support plate intersections,~~.~~

23~~c~~.If indications are identified that extend beyond the confines of the tube support plate,~~.~~

34~~d~~. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking,~~.~~ and

5.6 Reporting Requirements

5.6.7 Steam Generator Tube Inspection Report (continued)

4~~5e~~. If the calculated conditional burst probability based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1E-02, notify the NRC and provide an assessment of the safety significance of the occurrence.

5.6.8 EM Report

When a report is required by Condition C or I of LCO 3.3.3, "Event Monitoring (EM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

BASES

APPLICABLE SAFETY ANALYSES (continued)	forced flow rate, which is represented by the number of RCS loops in service. Both transient and steady state analyses include the effect of flow on the departure from nucleate boiling ratio (DNBR). The transient and accident analyses for the plant have been performed assuming both RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the two pump coastdown, single pump locked rotor, and rod withdrawal events (Ref. 1). The plant is designed to operate with both RCS loops in operation to maintain DNBR within limits during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant. RCS Loops - MODES 1 and 2 satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, two pumps are required at power. An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG ~~in accordance with the Steam Generator Tube Surveillance Program~~.
APPLICABILITY	In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the

BASES

APPLICABLE SAFETY ANALYSES

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 **the total primary to secondary LEAKAGE is 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analysis assumes the leakage from the faulted SG is limited to 1.42 gallons per minute (based on a reactor coolant system temperature of 578 ºF)**~~that primary to secondary LEAKAGE from all steam generators (SGs) is one gallon per minute or increases to one gallon per minute as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analysis.a 1 gpm primary to secondary LEAKAGE as the initial condition~~.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The USAR (Ref. 2) analysis for SGTR assumes the plant has been operating with a 5 gpm primary to secondary leak rate for a period of time sufficient to establish radionuclide equilibrium in the secondary loop. Following the tube rupture, the initial primary to secondary LEAKAGE safety analysis assumption is relatively inconsequential when compared to the mass transfer through the ruptured tube.

The SLB is more limiting for site radiation releases. The safety analysis for the SLB accident assumes **the total primary to secondary LEAKAGE is 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of**

accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analysis assumes the leakage for this repair method will be limited to 1.42 gallons per minute (based on a reactor coolant system temperature of 578 ^{o}F)~~the entire 1 gpm (at 70°F) primary to secondary LEAKAGE is through the affectedin one generator as an initial condition~~. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 100 or the staff approved licensing basis (i.e., a small fraction of these limits).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the reactor coolant pressure boundary (RCPB). LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

Seal welds are provided at the threaded joints of all reactor vessel head penetrations (spare penetrations, full-length Control Rod Drive Mechanisms, and thermocouple columns). Although these seals are part of the RCPB as defined in 10CFR50 Section 50.2, minor leakage past the seal weld is not a fault in the RCPB or a structural integrity concern. Pressure retaining components are differentiated from leakage barriers in the ASME Boiler and Pressure Vessel Code. In all cases, the joint strength is provided by the threads of the closure joint.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere

LCO

c. Identified LEAKAGE (continued)

with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified leakage must be evaluated to assure that continued operation is safe. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through Any One ~~Steam Generator (~~SG~~)~~

The limit of 150 gallons per day per ~~The 150 gallons per day (gpd) limit on one~~ SG is based on ~~implementation of the Steam Generator Voltage Based Alternate Repair Criteria and~~ ~~is more restrictive than standard operating leakage limits to provide additional margin to accommodate a crack which might grow at greater than the expected rate or unexpectedly extend outside the thickness of the tube support plate.~~the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). 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

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.15, “RCS Pressure Isolation Valve (PIV) Leakage,” measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE in excess of the LCO limits must be identified or reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1, B.2.1, and B.2.2

If unidentified LEAKAGE cannot be identified or cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals, gaskets, and pressurizer safety valves seats is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours. If the LEAKAGE source cannot be identified within 54 hours, then the reactor must be placed in MODE 5 within 84 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

ACTIONS (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

C.1, C.2.1, and C.2.2

If RCS identified LEAKAGE, other than pressure boundary LEAKAGE~~leakage~~ or primary to secondary LEAKAGE, is not within limits, then the reactor must be placed in MODE 3 within 6 hours. In this condition, 14 hours are allowed to reduce the identified leakage to within limits. If the identified LEAKAGE is not within limits within this time, the reactor must be placed in MODE 5 within 44 hours.

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

D.1 and D.2

If RCS pressure boundary LEAKAGE exists or if primary to secondary~~SG~~ LEAKAGE (150 gpd limit) is not within limits, the reactor must be placed in MODE 3 within 6 hours and in MODE 5 within 36 hours.

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. ~~Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems.~~

The RCS water inventory balance must be met with the reactor at steady state operating conditions (stable temperature, power level, equilibrium xenon, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows). The Surveillance is modified by two Notes. ~~Therefore, a~~ Note 1 states ~~is added allowing~~ that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper inventory

balance since calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, 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.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by monitoring containment atmosphere radioactivity. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.16, "RCS Leakage Detection Instrumentation."

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 24 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.14.2

~~This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions~~ This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.19, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as

described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state 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 Surveillance Frequency of 72 hours 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. 4).

BASES

REFERENCES

1. AEC "General Design Criteria for Nuclear Power Plant Construction Permits," Criterion 16, issued for comment July 10, 1967, as referenced in USAR, Section 1.2.

2. USAR, Section 14.5.

3. NEI 97-06, "Steam Generator Program Guidelines."

4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.19 Steam Generator (SG) Tube Integrity

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. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

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 5.5.8, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.8, tube integrity is maintained when the SG performance criteria are met.

BASES

BACKGROUND (continued)

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.8. 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 greater than the operational LEAKAGE rate limits in LCO 3.4.14, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via atmospheric steam dumps.

The analyse~~i~~s 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 **of 1 gallon per minute from the faulted SG or is assumed to increase to 1 gallon per minute as a result of accident induced conditions plus 150 gallons per day from the intact SG. When the voltage based repair criteria is implemented for Unit 2 (only), the safety analyses assume the leakage from the faulted SG is limited to** ~~from all SGs of 1 gallon per minute or is assumed to increase to 1 gallon per minute as a result of accident induced conditions except during the implementation of steam generator repairs on Unit 2 utilizing the voltage-based repair criteria. During the implementation of steam generator repairs on Unit 2 utilizing the voltage-based repair criteria, the total calculated primary to secondary side leakage from the faulted SG under main steam line~~

~~break conditions (outside containment and upstream of the main steam isolation valves), will not exceed~~ 1.42 gallons per minute (based on a reactor coolant system temperature of 578 °F). **For tubes that are left in service as part of the voltage based repair criteria, the probability of burst under main steam line break conditions shall be maintained below 1E-02 in accordance with the requirements of NRC Generic Letter (GL) 95-05.**

BASES

APPLICABLE SAFETY ANALYSES (continued)

For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to or greater than the LCO 3.4.17, "RCS Specific 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

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

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

In the context of this Specification, an 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, nor is the region of tube below the F* and EF* distances.

An SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.8, “Steam Generator Program,” and describe acceptable SG tube performance. The Steam Generator Program also provides the

LCO (continued)

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.

BASES

LCO (continued)

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 an SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed those discussed in the APPLICABLE SAFETY ANALYSES section above. 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 LCO 3.4.14, “RCS Operational LEAKAGE,” and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to an 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 in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to

APPLICABILITY (continued)

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.

A.1 and A.2

Condition A 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 or repaired in accordance with the Steam Generator Program as required by SR 3.4.19.2. 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 an SG tube that should have been plugged or repaired 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, Condition B applies.

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

ACTIONS A.1 and A.2 (continued)

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 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 or repaired prior to entering MODE 4 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.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 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 REQUIREMENTS SR 3.4.19.1

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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.19.1 (continued)

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 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 3.4.19.1. 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 5.5.8 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.19.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is repaired or removed from service by plugging. The tube repair criteria delineated in Specification 5.5.8 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.

Steam generator tube repairs are only performed using approved repair methods as described in the Steam Generator Program.

The Frequency of prior to entering MODE 4 following an SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged or repaired prior to subjecting the SG tubes to significant primary to secondary pressure differential.

BASES (continued)

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."

ENCLOSURE 3

Proposed Technical Specification Pages (revised)

Prairie Island Nuclear Generating Plant Units 1 and 2

Technical Specification Pages

1.1-3	5.0-18
3.4.14-2	5.0-19
3.4.14-3	5.0-20
3.4.19-1	5.0-21
3.4.19-2	5.0-22
5.0-13	5.0-30
5.0-14	5.0-31
5.0-15	5.0-38
5.0-16	5.0-39
5.0-17	5.0-40

20 pages follow

1.1 Definitions (continued)

$\bar{E}$ -AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 15 minutes, making up at least 95% of the total noniodine activity in the coolant.
LEAKAGE	LEAKAGE from the Reactor Coolant System (RCS) shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. RCS LEAKAGE through a steam generator to the Secondary System (primary to secondary LEAKAGE);

b. Unidentified LEAKAGE

All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. Pressure Boundary LEAKAGE

LEAKAGE (except primary to secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS identified LEAKAGE not within limit for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	C.1 Be in MODE 3. AND C.2.1 Reduce LEAKAGE to within limits. OR C.2.2 Be in MODE 5.	6 hours 14 hours 44 hours
D. Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	--------------------------NOTES-------------------------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. -- Verify RCS operational LEAKAGE within limits by performance of RCS water inventory balance.	24 hours
SR 3.4.14.2	--------------------------NOTE--------------------------- Not required to be performed until 12 hours after establishment of steady state operation. -- Verify primary to secondary LEAKAGE is $\leq$ 150 gallons per day through any one SG.	72 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.19 Steam Generator (SG) Tube Integrity

LCO 3.4.19 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged or repaired in accordance with the Steam Generator Program

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

---NOTE---
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged or repaired in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG inspection.	7 days
	AND	
	A.2 Plug or repair the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.19.1 Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.19.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged or repaired in accordance with the Steam Generator Program.	Prior to entering MODE 4 following an SG tube inspection

5.5 Programs and Manuals (continued)

5.5.8 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 or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired 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 inservice SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown 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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

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. For Unit 2, when tubes are left in service with predominantly axially oriented stress corrosion cracking at the tube support plate elevations, the probability of burst under main steam line break conditions shall be maintained below 1E-02 in accordance with the requirements of NRC Generic Letter (GL) 95-05.

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. For Unit 1, leakage is not to exceed 1 gpm per SG. For Unit 2, leakage from all sources, excluding the leakage attributed to the degradation associated with implementation of the voltage-based repair criteria, is not to exceed 1 gpm per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.14, "RCS Operational Leakage".

c. Provisions for SG tube repair criteria:

1. Unit 1 steam generator 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.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

2. Unit 2 steam generator tubes that meet the following criteria shall be plugged or repaired.

(a) Depth Based Criteria:

(1) Tubes found by inservice inspection containing flaws with a depth equal to or exceeding 50% of the nominal tube wall thickness. If significant general tube thinning occurs, this criterion is reduced to 40% wall penetration.

(2) Tubes found by inservice inspection containing flaws in the pressure boundary region of any: 1) sleeve; or 2) pressure boundary portion of the original tube wall in the sleeve-to-tube joint with a depth equal to or exceeding 25% of the nominal sleeve wall thickness.

(b) The following F* or EF* Alternate Repair Criteria may be applied as an alternative to the depth based criteria: Flaws may be left in service when they are located below F* or EF* defined below:

(1) F* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is below the midplane of the tubesheet, then all defects located below 1.07 inches from the bottom of this uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.07-inch span (not including eddy current uncertainty). This 1.07-inch span (not including eddy current uncertainty) is referred to as the F* region. If flaws are contained within the F* region, the tube shall be plugged or repaired.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

(2) EF* Criterion: If the bottom of the uppermost hardroll transition in the tubesheet is above the midplane of the tubesheet but at least 2.0 inches below the top of the secondary face of the tubesheet, then all defects located below 1.67 inches from the bottom of the uppermost hardroll transition (not including eddy current uncertainty) may be allowed to remain in service provided the tube does not contain any flaws within this 1.67-inch span (not including eddy current uncertainty). This 1.67-inch span (not including eddy current uncertainty) is referred to as the EF* region. If flaws are contained within the EF* region, the tube shall be plugged or repaired.

(c) The following Alternate Tube Support Plate Voltage-Based Repair Criteria may be applied as an alternative to the depth based criteria: For regions of the tube affected by predominately axially oriented outside diameter stress corrosion cracking confined within the thickness of the tube support plates the plugging or repair limit is as follows:

(1) If the bobbin voltage associated with the degradation is less than or equal to 2.0 Volts, the degradation is allowed to remain in service.

(2) If the bobbin voltage associated with the degradation is greater than 2.0 Volts, the tube shall be plugged or repaired unless the voltage is less than or equal to the upper voltage repair limit (calculated according to the methodology in GL 95-05 as supplemented) and a rotating pancake coil (or comparable examination technique) does not detect the flaw. In this latter case, the flaw may remain in service.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

(3) If an unscheduled mid-cycle inspection is performed, the following mid-cycle repair limits apply instead of the limits in Specifications 5.5.8.c.2.(c)(1) and 5.5.8.c.2.(c)(2) above. The mid-cycle repair limits are determined from the following equations:

$$V_{MURL} = \frac{V_{SL}}{1.0 + NDE + Gr\left(\frac{CL - \Delta t}{CL}\right)}$$

$$V_{MLRL} = V_{MURL} - (V_{URL} - 2.0)\left(\frac{CL - \Delta t}{CL}\right)$$

Where:

V_{URL} = upper voltage repair limit

V_{LRL} = lower voltage repair limit

V_{MURL} = mid-cycle upper voltage repair limit based on time into cycle

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

V_{MLRL} = mid-cycle lower voltage repair limit based on V_{MURL} and time into cycle

Δt = length of time since last scheduled inspection during which V_{URL} and V_{LRL} were implemented

CL = cycle length (time between two scheduled steam generator inspections)

V_{SL} = structural limit voltage

Gr = average growth rate per cycle length

NDE = 95 percent cumulative probability allowance for nondestructive examination uncertainty (i.e., a value of 20 percent has been approved by the NRC)

Implementation of these mid-cycle repair limits should follow the same approach as described in Specifications 5.5.8.c.2.(c)(1) and 5.5.8.c.2.(c)(2) above.

Note: The upper voltage repair limit is calculated according to the methodology in GL 95-05 as supplemented.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

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, and d.4 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. For the Unit 1 SGs, inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

3. For the Unit 2 SGs, 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.

    (a) During each Unit 2 SG refueling outage inspection, all tubes within that SG which have had the F* or EF* criteria applied will be inspected in the F* and EF* regions of the roll expanded region. The region of these tubes below the F* and EF* regions may be excluded from the inspection requirements.

    (b) Implementation of the SG tube and tube support plate repair criteria require a 100 percent bobbin coil inspection for hot leg and cold leg tube support plate intersections down to the lowest cold leg tube support plate with known outside diameter stress corrosion cracking (ODSCC) indications. The determination of the lowest cold leg tube support plate intersections having ODSCC indications shall be based on the performance of at least a 20 percent random sampling of tubes inspected over their full length.

    (c) SG tube indications left in service as a result of application of tube support plate voltage-based repair criteria shall be inspected by bobbin coil probe during all future refueling outages.

4. 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

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Program (continued)

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.

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.

1. There are no approved SG tube repair methods for the Unit 1 SGs.

2. For Unit 2, the following are approved repair methods:

(a) Alloy 690 tungsten inert gas welded sleeves in accordance with CEN-629-P, Revision 03-P,"Repair of Westinghouse Series 44 and 51 Steam Generator Tubes Using Leak Tight Sleeves".

(b) Hardroll expanding portions of tubes in the tubesheet in order to apply the F* and EF* criteria.

5.5 Programs and Manuals (continued)

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5.5 Programs and Manuals (continued)

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5.5 Programs and Manuals (continued)

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5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR) (continued)

b. The analytical methods used to determine the RCS pressure and temperature limits and Cold Overpressure Mitigation System setpoints shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves" (includes any exemption granted by NRC to ASME Code Case N-514).

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto. Changes to the curves, setpoints, or parameters in the PTLR resulting from new or additional analysis of beltline material properties shall be submitted to the NRC prior to issuance of an updated PTLR.

5.6.7 Steam Generator Tube Inspection Report

a. A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.8, Steam Generator (SG) Program. The report shall include:

1. The scope of inspections performed on each SG,

2. Active degradation mechanisms found,

3. Nondestructive examination techniques utilized for each degradation mechanism,

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

5.6 Reporting Requirements

5.6.7 Steam Generator Tube Inspection Report (continued)

5. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,

6. Total number and percentage of tubes plugged or repaired to date,

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

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

9. Repair method utilized and the number of tubes repaired by each repair method, and

10. The results of inspections performed under Specification 5.5.8.d.3(a) for all tubes that have defects below the F* or EF* distance, and were not plugged. The report shall include: a) identification of F* and EF* tubes; and b) location and extent of degradation.

b. For implementation of the voltage-based repair criteria to tube support plate intersections, notify the NRC staff prior to returning the steam generators to service should any of the following conditions arise:

1. If circumferential crack-like indications are detected at the tube support plate intersections,

5.6 Reporting Requirements

5.6.7 Steam Generator Tube Inspection Report (continued)

2. If indications are identified that extend beyond the confines of the tube support plate,

3. If indications are identified at the tube support plate elevations that are attributable to primary water stress corrosion cracking, and

4. If the calculated conditional burst probability based on the projected end-of-cycle (or if not practical, using the actual measured end-of-cycle) voltage distribution exceeds 1E-02, notify the NRC and provide an assessment of the safety significance of the occurrence.

5.6.8 EM Report

When a report is required by Condition C or I of LCO 3.3.3, "Event Monitoring (EM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.