September 29, 2005

Mr. Charles D. Naslund
Senior Vice President and Chief Nuclear Officer
Union Electric Company
Post Office Box 620
Fulton, MO 65251

SUBJECT: CALLAWAY PLANT, UNIT 1 - ISSUANCE OF AMENDMENT REGARDING THE STEAM GENERATOR REPLACEMENT PROJECT (TAC NO. MC4437)

Dear Mr. Naslund:

The U.S. Nuclear Regulatory Commission (the Commission or NRC) has issued the enclosed Amendment No. 168 to Facility Operating License No. NPF-30 for the Callaway Plant, Unit 1. The amendment consists of changes to the Technical Specifications (TSs) in response to your application dated September 17, 2004 (ULNRC-05056), as supplemented by the letters dated February 11 (ULNRC-05117), May 26 (ULNRC-05145), June 17 (ULNRC-05157), June 17 (ULNRC-05159), July 15 (ULNRC-05169), July 29 (ULNRC-05178), August 16 (ULNRC-05188), and September 6 (ULNRC-05192), 2005.

The amendment is to support the installation of replacement steam generators (SGs) at Callaway during the refueling outage in the fall of 2005. The amendment changes the following affected TSs: the reactor core safety limits (TS 2.1.1), reactor trip system and engineered safety feature actuation system instrumentation (TSs 3.3.1 and 3.3.2), reactor coolant system (RCS) limits (TS 3.4.1), RCS loops (TSs 3.4.5, 3.4.6, and 3.4.7), RCS operational leakage (TS 3.4.13), SG tube integrity (the new TS 3.4.17), main steam safety valves (TS 3.7.1), SG tube surveillance program (TS 5.5.9), containment integrated leakage rate testing (ILRT) program (TS 5.5.16), and SG tube inspection report (TS 5.6.10).

The amendment also revises (1) the affected transient analyses such as an excessive increase in secondary steam flow event, loss of normal feedwater event, transient mass and energy releases, radiological consequences of associated events, and containment pressure/temperature responses; and (2) the nuclear steam and supply system (NSSS) design parameters and transients, and fatigue usage factors and stresses for the replacement SGs.

The application was submitted with the Westinghouse Electric Company topical report WCAP-16265-P, "Callaway Replacement Steam Generator Program NSSS Licensing Report," which contained information designated as proprietary. By letter dated November 10, 2004, the NRC stated that the information designated as proprietary in WCAP-16265-P would be withheld from public disclosure. In some of the supplemental letters providing responses to NRC requests for additional information, portions of the information provided was designated as proprietary. By three letters dated September 7, 2005, the NRC stated that the information designated as proprietary in the supplemental letters dated February 11, May 26, and June 17, 2005, would also be withheld from public disclosure.

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/
Jack Donohew, Senior Project Manager, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosures: 1. Amendment No. 168 to NPF-30
2. Safety Evaluation

cc w/encl: See next page

A copy of the related Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

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cc w/encls: See next page

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ACCESSION NO.: ML052570054 Package ML052570086 TS ML052730083

OFFICE	PDIV-2/PM	PDIV-2/LA	IROB-A/SC	EEIB-A/SC	SRXB-B/SC	SPSB-C/SC	EMCB-C/SC	OGC	PDIV-2/(A)SC
NAME	JDonohew	LFeizollahi	RTjader for TBoyce	AHowe	JNakoski	MKotzalas	LLund		DCollins
Section	All	All	3.1.3.2 3.2.2 3.2.3	3.1.3.2	3.4.3.11.(5)	3.6	3.2	All	All
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UNION ELECTRIC COMPANY

CALLAWAY PLANT, UNIT 1

DOCKET NO. 50-483

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 168
License No. NPF-30

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Union Electric Company (UE, the licensee) dated September 17, 2004, as supplemented by letters dated February 11, May 26, June 17 (two letters), July 15, July 29, August 16, and September 6, 2005, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-30 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 168 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This amendment is effective as of its date of issuance, and shall be implemented before entry into Mode 5 during the restart from the fall 2005 refueling outage when the replacement steam generators are installed and shall include (1) revision of the pressure temperature limits report to change the cold overpressure mitigation system setpoints to reflect no reactor coolant pump operation restrictions and (2) incorporation of the Technical Specification (TS) Bases changes identified in the licensee's letter of September 6, 2005, into the TS Bases.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/
Daniel S. Collins, Acting Chief, Section 2
Project Directorate IV
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: September 29, 2005

ATTACHMENT TO LICENSE AMENDMENT NO. 168

RENEWED FACILITY OPERATING LICENSE NO. NPF-30

DOCKET NO. 50-483

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT
2	2
4	4
1.1-3	1.1-3
2.0-2	2.0-2
3.3-11	3.3-11
3.3-17	3.3-17
3.3-18	3.3-18
3.3-19	3.3-19
3.3-20	3.3-20
3.3-21	3.3-21
3.3-22	3.3-22
3.3-23	3.3-23
3.3-24	3.3-24
3.3-31	3.3-31
3.3-38	3.3-38
3.3-39	3.3-39
3.3-40	3.3-40
3.3-41	3.3-41
3.3-42	3.3-42
3.3-43	3.3-43
3.3-44	3.3-44
3.3-45	3.3-45
3.4-1	3.4-1
3.4-2	3.4-2
3.4-9	3.4-9
3.4-11	3.4-11
3.4-12	3.4-12
3.4-14	3.4-14
3.4-30	3.4-30
3.4-31	3.4-31
--------	3.4-44
--------	3.4-45
--------	3.4-46
3.7-3	3.7-3
5.0-10 to 5.0-36	5.0-10 to 5.0-28

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 168 TO FACILITY OPERATING LICENSE NO. NPF-30

UNION ELECTRIC COMPANY

CALLAWAY PLANT, UNIT 1

DOCKET NO. 50-483

1.0 INTRODUCTION

By application dated September 17, 2004 (Agencywide Documents Access Management System (ADAMS) Accession No. ML042870364), as supplemented by letters dated February 11, May 26, June 17 (two letters), July 15, July 29, August 16, and September 6, 2005 (ADAMS Accession Nos. ML050550181, ML051590301, ML051780328, ML051790249, ML052070584, ML052220138, ML052360244, and ML052630485, respectively), Union Electric Company (the licensee) requested changes to Appendix A, the Technical Specifications (TSs), of the Facility Operating License No. NPF-30 for the Callaway Plant, Unit 1 (Callaway). The license amendment request (LAR) is to support the installation of replacement steam generators (SGs) at Callaway during the refueling outage in the fall of 2005. The amendment would change the following specifications in the Callaway TSs:

- The reactor core safety limits in TS 2.1.1,
- The reactor trip system (RTS) and engineered safety feature actuation system (ESFAS) instrumentation in TSs 3.3.1 and 3.3.2,
- The reactor coolant system (RCS) limits in TS 3.4.1,
- The RCS loops in TSs 3.4.5, 3.4.6, and 3.4.7,
- The RCS operational leakage in TS 3.4.13,
- The SG tube integrity in the new TS 3.4.17 (which also adds to the TS Table of Contents),
- The main steam safety valves (MSSVs) in TS 3.7.1,
- The SG tube surveillance program (SGTSP) in TS 5.5.9,
- The containment integrated leakage rate testing (ILRT) program in TS 5.5.16, and
- The SG tube inspection report in TS 5.6.10.

The application was submitted with the Westinghouse Electric Company topical report WCAP-16265-P, "Callaway Replacement Steam Generator Program NSSS [Nuclear Steam and Supply System] Licensing Report," which contained information designated as proprietary. By letter dated November 10, 2004, the Nuclear Regulatory Commission (NRC) stated that the information designated as proprietary in WCAP-16265-P would be withheld from public disclosure. In some of the supplemental letters providing responses to NRC requests for additional information, portions of the information provided was designated as proprietary. By

three letters dated September 7, 2005, the NRC stated that the information designated as proprietary in the supplemental letters dated February 11, May 26, and June 17, 2005, would also be withheld from public disclosure.

The staff conducted a meeting with the licensee on May 18, 2005, to discuss its responses to questions for additional information from the NRC staff on this LAR. The meeting summary (ADAMS Accession No. ML051460111) was issued on June 3, 2005.

The supplemental letters dated February 11, May 26, June 17 (two letters), July 15, July 29, August 16, and September 6, 2005, provided additional information that clarified the application, did not expand the scope of the application as originally noticed and did not change the NRC staff’s original proposed no significant hazards consideration determination published in the *Federal Register* on November 23, 2004 (69 FR 68185).

2.0 REGULATORY EVALUATION

In 10 CFR 50.36, the NRC issued a rule and established its regulatory requirements related to the content of TSs. In doing so, the NRC emphasized those matters related to the prevention of accidents and mitigation of consequences of such accidents. As recorded in the Statements of Consideration, Technical Specifications for Facility Licenses: Safety Analysis Reports (33 FR 18610, December 17, 1968), the NRC noted that licensees are expected to incorporate into their plant TSs those items that are directly related to maintaining the integrity of the physical barriers designed to contain radioactivity. Pursuant to 10 CFR 50.36, TSs are required to include items in five specific categories related to station operation. Specifically, those categories include: (1) safety limits, limiting safety system settings (LSSSs), and limiting control settings; (2) LCOs; (3) SRs; (4) design features; and (5) administrative controls. However, the rule does not specify the particular requirements to be included in a plant's TSs.

Additionally, 10 CFR 50.36(c)(2)(ii) sets forth four criteria to be used in determining whether a LCO is required to be included in the TS for a certain item. These criteria are as follows:

1. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

2. A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

3. A structure, system, or component (SSC) that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

4. A SSC which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

In additional to 10 CFR 50.36, there are other regulatory requirements that apply to the proposed amendment. The evaluation of the amendment request is divided into the following areas of review: (1) instrumentation and controls, (2) SG tube integrity, (3) plant systems, (4)

reactor systems, (5) dose consequences for design basis accidents (DBAs), (6) containment integrity, (7) RCS loop piping and supports, and pressurizer, and (8) balance of plant considerations. The regulatory requirements for each of these areas of review will be addressed separately in the specific section of this safety evaluation (SE) that addresses that area of review.

3.0 TECHNICAL EVALUATION

The licensee proposed changes to the Callaway TSs to support the installation of replacement SGs in the fall 2005 refueling outage. In its application, the licensee also stated that it intended to apply leak-before-break (LBB) criteria to the pressurizer surge line and would submit this request on or about November 30, 2004; however, the licensee later stated in a supplemental letter that it would not apply for LBB for the pressurizer surge line.

The following areas of review address the proposed changes to the TSs that are listed in Section 1.0 of the SE:

- Section 3.1, "Instrumentation and Controls (I&C) Review," addresses the changes to TSs 3.3.1 and 3.3.2;
- Section 3.2, "SG Tube Integrity Review," addresses the changes to TS definition of leakage and TSs 3.4.13, 3.4.17, 5.5.9, and 5.6.10;
- Section 3.3, "Plant Systems Review," addresses the changes to TS 3.7.1;
- Section 3.4, "Reactor Systems Review," addresses the changes to TSs 2.1.1, 3.4.1, 3.4.5, 3.4.6, and 3.4.7;
- Section 3.5, "Dose Consequences Review for DBAs," does not address any of the changes to the TSs;
- Section 3.6, "Containment Integrity Review," which addresses the changes to TS 5.5.16;
- Section 3.7, "RCS Loop Piping and Supports, and Pressurizer," which also does not address any changes to the TSs; and
- Section 3.8, "Balance of Plant Evaluation Considerations," which also does not address any changes to the TSs.

The following sections constitute the NRC staff's review of the licensee's proposal to replace the original SGs with the replacement SGs and the proposed changes to the TSs. For the sections of this SE that do not address any change to the TSs, the basis for the NRC staff to conclude that continued plant operation with the replacement SGs is acceptable is addressed.

3.1 I&C Review

3.1.1 Introduction

By application dated September 17, 2004, and supplemented by letters dated May 26 and July 15, 2005, the licensee submitted an LAR for the Callaway Plant in support of replacement SGs. The proposed TS changes involved with changes to I&C trip setpoints are the following:

- Changes to TS Table 3.3.1-1, including a change to an input parameter for the overpower Delta-T (OPΔT) function, and

- Changes to TS Table 3.3.2-1.

3.1.2 Regulatory Evaluation

Nuclear power plants are licensed to operate at a specified core thermal power. The instrument measurement uncertainty should be considered to avoid exceeding the power level assumed in the design-basis transient and accident analysis. The safety-related instrument trip setpoints are calculated to ensure that sufficient allowance exists between the trip setpoint and the safety limit to account for instrument uncertainties. The Commission's regulatory requirements related to this review can be found in 10 CFR 50.36(c)(1)(ii)(A) which requires that, where a limiting safety system setting (LSSS) is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct abnormal situations before they exceed a safety limit. LSSSs are for automatic protective devices related to variables having significant safety functions. Setpoints found to exceed TS limits are considered a malfunction of an automatic safety system. Such an occurrence could challenge the integrity of the reactor core, reactor coolant pressure boundary (RCPB), containment, and associated safety systems. Regulatory Guide (RG) 1.105, Revision 3, "Setpoint for Safety-Related Instrumentation," is used to evaluate the conformance of setpoints with 10 CFR 50.36.

3.1.3 Technical Evaluation

3.1.3.1 Suitability of Existing Instruments

The Callaway plant currently has Westinghouse Model F SGs installed. The licensee plans to install Framatome-designed Model 73/19T replacement SGs during Refuel 14 in fall of 2005. In response to NRC staff's question whether the replacement SG project affects any safety-related instrumentation, the licensee stated that there are no functional changes to any safety-related instrumentation associated with the replacement SGs other than the independent decision to eliminate the trip time delay (TTD) circuitry of the SG water level low-low trip function. There are, however, some component modifications and upgrades to the SG water level instrumentation and the RCS flow instrumentation as a result of the replacement SGs. There are some nominal trip setpoints and TS allowable value (AV) changes in some of the RTS and ESFAS actuation functions to support the replacement SG project.

3.1.3.1.1 TTD Elimination

The licensee stated that the TTD circuitry of the SG water level low-low trip function was added to the original design under an NRC-approved modification which was installed during the spring of 1989. The TTD was installed to provide a short time delay before a reactor trip signal was generated due to low-low SG level. This time delay gave the reactor operator time to manually regain control of SG water levels to avoid, if possible, a reactor trip. The licensee stated that the replacement SG design is much less susceptible to level fluctuations and, therefore, the trip delay is no longer required. The licensee explained that deleting the TTD circuitry will result in less design complexity and less TS-required surveillance testing. Thus,

eliminating TTD circuitry surveillance testing will result in substantial man-hour savings during channel operational tests.

The original Callaway licensing basis did not include the TTD circuitry. The NRC approved the adding of the TTD circuitry in Amendment No. 43, which was issued on April 14, 1989. The proposed amendment requests that the 7300 process protection system be modified to eliminate the TTD circuitry. Based on its review of the justification provided by the licensee in the submittals, as discussed above, the staff finds that the elimination of the TTD circuitry is acceptable because the time delay for the reactor trip is no longer needed for the replacement SGs.

3.1.3.1.2 SG Water Level Instrumentation Modifications

The SG water level instrumentation is being modified in the following three ways: (1) eliminate all shared impulse tubing, (2) replace all associated root valves, and (3) provide new range instrument tap locations. These modifications are addressed below.

The licensee stated that the original Westinghouse SG design has fewer instrument taps than the replacement SGs. Seven of the instrument reference legs in the current SGs are shared between four upper taps; however, the replacement SG design has a sufficient number of instrument taps such that all shared arrangements can be eliminated. This will eliminate any instrument interaction when removing an instrument from service or returning an instrument to service. The licensee also stated that the existing root valves have experienced a higher than average rate of packing leakage. The replacement SG design will upgrade all root valves, piping and condensate pots associated with the SG narrow range, wide range and steam flow instrumentation, and will use stainless steel components. These design upgrades are intended to improve system integrity and reliability. Based on the above discussion, the NRC staff finds that these design upgrades are acceptable.

3.1.3.1.3 RCS Flow Instrumentation

TS Table 3.3.1-1 Function 10, “Reactor Coolant Flow - Low,” allowable value units are to be changed from "% [percent] of loop minimum measured flow" to "% of indicated loop flow." This change was recommended by Westinghouse in a nuclear safety advisory letter NSAL-00-008, “Reactor Coolant Loop Flow Asymmetry,” dated May 22, 2000.

In providing an explanation for this proposed change, the licensee will also modify the TS Basis Section B 3.3.1, for this function. The licensee will state in the TS Bases that at the beginning of each cycle the plant will normalize the RCS flow transmitters during zero power, normal operating pressure, normal operating temperature (NOP/NOT) conditions such that they indicate at 100 percent flow in each respective loop. This normalization is then verified to be valid during power ascension and again at 100 percent rated thermal power (RTP). The bistables for the low RCS flow trip function are calibrated separately to verify that they are set at the nominal trip setpoint of 90 percent of span. The nominal trip setpoint is based on the loop-specific normalized flow input from each of the three RCS flow transmitters per RCS loop. This change will allow the licensee to normalize the RCS flow transmitters for each RCS loop separately instead of normalizing all four loops to the same RCS flow. In either case, the trip setpoint remains a percentage of the loop flow and this percentage for the trip is not being changed. Because the trip setpoint remains a percentage of the loop flow and this percentage is not being changed, the NRC staff finds that the proposed change meets 10 CFR 50.36 and is, therefore, acceptable.

3.1.3.2 Instrument Setpoint Methodology

The TSs provide the LSSS as an AV. During reviews of proposed license amendments that contain changes to LSSS setpoints, the staff identified concerns regarding the method used by licensees to determine the AVs listed in the TSs. AVs are used in the TSs as LSSS to provide acceptance criteria for determination of instrument channel operability during periodic surveillance testing. The AV is, therefore, an operability limit in the TSs, but the TS Bases must state that the limiting trip setpoint preserves the safety limit and is therefore the LSSS required by 10 CFR 50.36. In order for the staff to assess the acceptability of this LAR, by letter dated May 4, 2005, the staff requested the licensee to provide additional information related to:

1. The setpoint methodology used to establish AVs associated with LSSS setpoints.

2. Discuss how the methodology and controls in place at the plant ensure that the analytical limit (AL) associated with an LSSS will not be exceeded.

3. How the TS surveillance ensure the operability of the instrument channel.

By supplemental letters dated May 26, July 15, and September 6, 2005, the licensee provided the additional information related to the instrument setpoint methodology and the plant procedures to ensure the operability of the instrument channel. The changes to TS Tables 3.3.1-1 and 3.3.2-1 that were submitted in the September 6, 2005, letter revised and superceded the TS changes submitted in the May 26, 2005, letter.

The licensee stated that the methodology for calculation of the uncertainties is a square root sum of the squares (SRSS) approach. The Callaway replacement SG project determines a performance-based AV for the RTS/ESFAS functions related to the SG. The criterion for the performance-based AV is controlled by both plant procedures and the TSs. In TSs 3.3.1 and 3.3.2, the requirement is to verify that the instrumentation is “Operable.” This verification is performed every 184 days by performance of the channel operability test (COT) confirming that the channel meets the stated AV. Because the AVs for the replacement SGs are based on the “Rack Calibration Accuracy (RCA),” it then follows that the as-found condition of the channel must be within the calibration accuracy to be considered “Operable.” The licensee stated that the setpoint methodology requires that the channel is always returned to within the RCA.

The licensee will trend as-found and as-left setpoint data obtained during COTs for the SG trip functions to confirm that the rack drift assumptions used in the plant setpoint methodology are valid. If the trending evaluation determines that a channel is performing inconsistently with the uncertainty allowances applicable to the periodic surveillance test being performed, the channel will be evaluated under the licensee's corrective action program. If the channel is not capable of performing its specified safety function, it shall be declared inoperable. For the RTS/ESFAS trip functions affected by the replacement SG, the AV for the function is established at a slight difference in percent of span from the normal trip setpoint by an amount equal to the RCA in the direction of the safety analysis limit for the particular trip function. If the as-found setting for any of these specific trip function channels is found to be outside the two-sided calibration tolerance band on either side of the nominal trip setpoint, including any AV exceeded, then a corrective action report (CAR) will be written and the affected channel will be evaluated under the licensee's corrective action program.

The proposed changes to TS Tables 3.3.1-1 and 3.3.2-1 are to add and revise footnotes to the tables. The proposed changes are to:

1. Revise footnote (a) of TS Table 3.3.1-1 to state "The allowable Value defines the limiting safety system setting **except for Trip Functions 14.a and 14.b (the Nominal Trip Setpoint defines the limiting safety system setting for these Trip Functions)**. See the Bases for the **Nominal** Trip Setpoints."

2. Revise footnote (a) of TS Table 3.3.2-1 to state "The allowable Value defines the limiting safety system setting **except for Functions 1.e, 4.e.(1), 5.c, 5.e.(1), 6.d.(1), and 6.d.(2) (the Nominal Trip Setpoint defines the limiting safety system setting for these Functions)**. See the Bases for the **Nominal** Trip Setpoints."

3. Add the following new footnote (q) to TS Table 3.3.1-1 and footnote (s) to TS Table 3.3.2-1 to state the following two items:

    a. "If the as-found instrument channel setpoint is conservative with respect to the Allowable Value, but outside its as–found test acceptance criteria band, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service. If the as-found instrument channel setpoint is not conservative with respect to the Allowable Value, the channel shall be declared inoperable."

    b. "The instrument channel setpoint shall be reset to a value that is within the as-left setpoint tolerance band on either side of the Nominal Trip Setpoint, or to a value that is more conservative than the Nominal Trip Setpoint; otherwise, the channel shall be declared inoperable. The Nominal Trip Setpoints and the methodology used to determine the as-found acceptance criteria band and the as-left setpoint tolerance band shall be specified in the Bases."

The reference in item 3.b above to the "Bases" is a reference to the TS Bases. The licensee also provided its changes to the TS Bases for TS Tables 3.3.1-1 and 3.3.2-1 that go along with the above footnotes in its September 6, 2005, supplemental letter.

For the revised footnotes (a) for TS Tables 3.3.1-1 and 3.3.2-1, the words given in **bold** above were the words proposed to be added to the footnotes. No words are proposed to be deleted from the two footnotes. The reason for the proposed change is to separate the functions in the two TS tables into the following two categories: (1) the functions in the tables for which the Nominal Trip Setpoint is the LSSS and (2) the functions in the tables for which the allowable value is the LSSS. The functions that are in Category 1 are those listed in the proposed footnotes (a). The word "Nominal" is added to the second sentence of the footnotes (a) because the Nominal Trip Setpoints are not given in TS Tables 3.3.1-1 and 3.3.2-1, but are discussed in the TS Bases for these tables.
Based on its review of the September 6, 2005, letter, the above footnotes and the licensee-identified changes to the TS Bases, the NRC staff finds that the above footnotes address the staff's concern raised in the staff's May 4, 2005, RAI. With this being true, the NRC staff concludes that the proposed footnotes assure that the associated RTS and ESFAS functions are operable and will perform their safety functions. Based on this, the NRC staff further

concludes that these proposed changes meet 10 CFR 50.36 and are, therefore, acceptable.

3.1.3.3 I&C-related TS Changes Related to Replacement SGs

The proposed I&C TS changes for the replacement SGs are the following:

3. Condition W in LCO 3.3.1, “Reactor Trip System (RTS) Instrumentation,” will no longer be used. RTS Function 14.c in TS Table 3.3.1-1 will be deleted. The TTD portion of the SG Water Level Low-Low trip function will be deleted during Refuel 14, including the Vessel ªT Equivalent (Power-1, Power-2) channels and the delay timers.

The staff’s evaluation is addressed in Section 3.1.3.1.1 of this SE. The NRC staff concluded in that section that the request for TTD circuitry elimination was acceptable. Because the proposed changes implement the elimination of TTD, the NRC staff concludes that they are acceptable.

4. Note (m) in TS Table 3.3.1-1 is deleted and the allowable value units for Function 10, Reactor Coolant Flow - Low, are changed from "% [percent] of loop minimum measured flow" to "% of indicated loop flow."

The staff’s evaluation is addressed in Section 3.1.3.1.3 of this SE. The NRC staff concluded in that section that the requested change was acceptable. Based on this, because the trip setpoint remains a percentage of loop flow and this percentage is not being changed, the NRC staff concludes that the proposed TS change meets 10 CFR 50.36 and is, therefore, acceptable.

5. Condition M in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," will no longer be used. ESFAS Function 5.e.(3) and 6.d.(3) in TS Table 3.3.2-1 will be deleted. The TTD portion of the SG Water Level Low-Low feedwater isolation and auxiliary feedwater actuation functions will be deleted during Refuel 14, including the Vessel ªT Equivalent (Power-1, Power-2) channels and the delay timers.

These proposed changes are part of the licensee's request to eliminate the TTD function. The staff’s evaluation is addressed in Section 3.1.3.1.1 of this SE. The staff concluded in that section that the request for to eliminate the TTD circuitry was acceptable. Because the proposed changes implement the elimination of TTD, the NRC staff concludes that they are acceptable.

6. The AVs for the following trip functions are decreased from $25.2 percent of narrow range instrument span to $20.6 percent of narrow range instrument span to reflect the replacement SGs and associated setpoint calculations:

    a. TS Table 3.3.1-1, RTS Function 14.a, SG Water Level Low-Low signal (adverse containment environment). A note (q) was added. The note (q) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel’s trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the

safety analysis limit.

b. TS Table 3.3.2-1, ESFAS Function 5.e.(1), Turbine Trip and Feedwater Isolation by SG Water Level Low-Low signal (adverse containment environment); A note (s) was added. The note (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

c. TS Table 3.3.2-1, ESFAS Function 6.d.(1), Auxiliary Feedwater actuation by SG Water Level Low-low signal (adverse containment environment). A note (s) was added. The note (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

The purpose of the low-low SG water level trip function is to actuate the auxiliary feedwater (AFW) system prior to uncovering the SG tubes and, thus, provide protection against a loss of heat sink. The SGs are the heat sink for the reactor. As discussed in WCAP-16265-P, the SG water level low-low trip function has been modified to allow a lower trip setpoint under normal containment environmental conditions. The environmental allowance modifier (EAM) circuitry reduces the potential for inadvertent trips via the EAM, enabled on containment pressure exceeding its setpoint. Because the SG water level transmitters are located inside containment, they may experience adverse environmental conditions due to feedline break. The EAM function is used to monitor the presence of adverse containment conditions (elevated pressure) and enables the SG water level low-low (Adverse) trip setpoint to reflect the increased transmitter uncertainties due to this harsh environment. The EAM enables a lower SG water level low-low (Normal) trip setpoint when these conditions are not present, thus allowing more margin to trip for abnormal operating conditions. The trip setpoint for the containment pressure - environmental allowance modifier bistables is #1.5 psig.

By letter dated May 26, 2005, the licensee provided the value for each uncertainty term and the calculation results for the safety-related setpoints that are being changed because of the replacement SGs. Based on the review of the licensee's setpoint methodology, as discussed in Section 3.1.3.2 of this SE, the NRC staff concludes that the proposed setpoints for RTS Function 14.a, and ESFAS Functions 5.e.(1) and 6.d.(1) meet 10 CFR 50.36 and are, therefore, acceptable.

7. The AVs for the following trip functions are decreased from $19.8 percent of narrow range instrument span to $16.6 percent of narrow range instrument span to reflect the replacement SGs and associated setpoint calculations:

a. TS Table 3.3.1-1, RTS Function 14.b, SG Water Level Low-Low signal (normal containment environment); A note (q) was added. The note (q) states that if a channel is found with an actual trip setpoint value outside its two-sided

calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

b. TS Table 3.3.2-1, ESFAS Function 5.e.(2), Turbine Trip and Feedwater Isolation by SG Water Level Low-Low signal (normal containment environment); A note (s) was added. The note (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

c. TS Table 3.3.2-1, ESFAS Function 6.d.(2), AFW actuation by SG Water Level Low-low signal (normal containment environment). A note (s) was added. The note (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

As stated above, the purpose of the low-low SG water level trip function is to actuate the AFW system prior to uncovering the SG tubes and, thus, provides protection against a loss of heat sink. The SGs are the heat sink for the reactor. As discussed in WCAP-16265-P, the SG water level low-low trip function has been modified to allow a lower trip setpoint under normal containment environmental conditions.

By letter dated May 26, 2005, the licensee provided the value for each uncertainty term and the calculation results for the safety-related setpoints that are being changed because of the replacement SGs. Based on the review of the licensee's setpoint methodology, as discussed in Section 3.1.3.2 of this SE, the NRC staff finds that the proposed setpoints for RTS Function 14.b and ESFAS Functions 5.e.(2) and 6.d.(2) meet 10 CRR 50.36 and are, therefore, acceptable.

8. The AV for safety injection on steam line pressure - low signal (ESFAS Function 1.e in TS Table 3.3.2-1) will be increased from $571 psig to $610 psig (with a footnote (s) added) to reflect the replacement SGs and associated setpoint calculations. The footnote (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint

established in accordance with the plant setpoint methodology to protect the safety analysis limit.

The "steam line pressure - low" function provides protection against (1) the main steam line break (MSLB) accident, (2) the main feed line break (MFLB) accident, and (3) the inadvertent opening of an SG relief or safety valve. This function is anticipatory in nature and has lead/lag time constants specified in the TSs as note (c), which is not being changed because of the replacement SGs.

By letter dated May 26, 2005, the licensee provided the value for each uncertainty term and the calculation results for the safety-related setpoints that are being changed because of the replacement SGs. Based on the review of the licensee's setpoint methodology, as discussed in Section 3.1.3.2 of this SE, the NRC staff finds that the proposed setpoint for ESFAS Function 1.e meets 10 CFR 50.36 and is, therefore, acceptable.

9. The AV for steam line isolation on steam line pressure - low signal (ESFAS Function 4.e.(1) in TS Table 3.3.2-1) will be increased from $571 psig to $610 psig (with a footnote (s) added) to reflect the replacement SGs and associated setpoint calculations. The footnote (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

The "steam line pressure - low" provides protection against the (1) MSLB accident, (2) MFLB accident, and (3) inadvertent opening of an SG relief or safety valve. This function is anticipatory in nature and has a lead/lag time constants specified in the TS as note (c), which is not being changed because of the replacement SGs.

By letter dated May 26, 2005, the licensee provided the value for each uncertainty term and the calculation results for the safety-related setpoints that are being changed because of the replacement SGs. Based on the review of the licensee's setpoint methodology, as discussed in Section 3.1.3.2 of this SE, the NRC staff finds that the proposed setpoints for ESFAS Function 4.e.(1) meet 10 CFR 50.36 and are, therefore, acceptable.

10. The AV for turbine trip and feedwater isolation on an SG water level high-high signal (ESFAS Function 5.c in TS Table 3.3.2-1) will be increased from #79.8 percent of narrow range instrument span to #91.4 percent of narrow range instrument span to reflect the replacement SGs and associated setpoint calculations. The footnote (s) states that if a channel is found with an actual trip setpoint value outside its two-sided calibration tolerance band, the channel's trip setpoint shall be restored to within the as-left calibration tolerance band on either side of the Nominal Trip Setpoint established in accordance with the plant setpoint methodology to protect the safety analysis limit.

The SG water level high-high function protects the plant against excessive feedwater flow by closing the main feedwater (MFW) control valves, tripping the turbine, and tripping the reactor.

By letter dated May 26, 2005, the licensee provided the value for each uncertainty term and the calculation results for the safety-related setpoints that are being changed because of the replacement SGs. Based on the review of the licensee's setpoint methodology, as discussed in Section 3.1.3.2 of this SE, the NRC staff finds that the proposed setpoints for ESFAS Function 5.c meets 10 CFR 50.36 and are, therefore, acceptable.

3.1.4 Conclusions

Based on the review of the Callaway submittals related to the I&C instrumentation for the replacement SGs, as discussed above, the NRC staff concludes that the Callaway I&C systems

will continue to perform their intended safety functions as required by the TSs and that the TTD circuitry may be eliminated from from the SG water level low-low ESFAS function. Based on this, the NRC staff concludes that the proposed changes to RTS/ESFAS Tables 3.3.1-1 and 3.3.2-1, as discussed in Section 3.1.3.3 of this SE, are acceptable.

3.2 SG Tube Integrity Review

3.2.1 Introduction

This section of the SE addresses that part of the LAR that concerns maintaining SG tube integrity. This part of the LAR is the culmination of NRC and industry efforts since the mid-1990s to develop a programmatic, largely performance-based regulatory framework for ensuring SG tube integrity. The supplemental letter dated June 17, 2005, made minor revisions that clarified the amendment request submitted in the licensee's application. The scope of the TS amendment request that concerns SG tube integrity is the following:

1. Revised TS 3.4.13, "RCS Operational Leakage"
2. New TS 3.4.17, "Steam Generator (SG) Tube Integrity" (which also add the new TS 3.4.17 to the TS Table of Contents)
3. Revised TS 5.5.9, "Steam Generator (SG) Program" (which also changes the pages numbers for TSs 5.6 and 5.7 in the Table of Contents)
4. Revised TS 5.6.10, "Steam Generator Tube Inspection Report"

The licensee also included the following revised TS Bases pages that account for the installation of the replacement SGs:

5. Revised TS Bases B 3.4.4, "RCS Loops - Modes 1 and 2"
6. Revised TS Bases B 3.4.5, "RCS Loops - Mode 3"
7. Revised TS Bases B 3.4.6, "RCS Loops - Mode 4"
8. Revised TS Bases B 3.4.7, "RCS Loops - Mode 5, Loops Filled"
9. Revised TS Bases B 3.4.13, "RCS Operational LEAKAGE"
10. New TS Bases B 3.4.17, "Steam Generator (SG) Tube Integrity"

The proposed new TS 3.4.17, in conjunction with the proposed revisions to administrative controls in TS 5.5.9, would establish in the Callaway TSs a new programmatic, largely performance-based framework for ensuring SG tube integrity. The licensee-identified TS Bases B 3.4.17 documents the licensee's bases for this framework. The proposed TS 3.4.17 would establish new LCOs related to SG tube integrity; namely, (1) SG tube integrity shall be maintained, and (2) all SG tubes satisfying the tube repair criteria (i.e., tubes with measured flaw sizes exceeding the tube repair criteria) shall be plugged in accordance with the SG Program. TS 3.4.17 would also include surveillance requirements (SRs) to verify that the above LCOs are met in accordance with the SGTSP in revised TS 5.5.9.

The proposed revised TS 5.5.9 would require establishing and implementing a program that ensures that SG tube integrity is maintained. SG tube integrity is defined in the proposed TSs in terms of specified performance criteria for structural and leakage integrity. The revised TS 5.5.9 would also (1) provide for monitoring the condition of the tubes relative to these performance criteria during each SG tube inspection and for ensuring that tube integrity is maintained between scheduled inspections of the SG tubes, (2) retain the currently specified

tube repair limit of 40 percent of the nominal wall thickness, and (3) delete currently specified tube repair limits for laser welded sleeves and Electrosleeves, since currently specified provisions for these types of repairs are also deleted from this revised specification. These previously authorized tube repair methods are no longer applicable to the replacement SGs.

The proposed changes to TS 5.6.10 revise the existing requirements for, and the contents of, the SG tube inspection report consistent with the proposed revisions to TS 5.5.9. The current requirement for a 12-month report would be changed to a 180-day report.

The proposed amendment includes proposed revisions to TS 3.4.13 and identified changes to the TS 3.4.13 Bases. The proposed changes would delete the current LCO limit of 600 gallons per day (gpd) for total primary-to-secondary leakage through all SGs, but would retain the current LCO limit of 150 gpd for primary-to-secondary leakage from any one SG. Retaining this latter requirement effectively ensures that total primary-to-secondary leakage through all the SGs is not allowed to exceed 600 gpd. (Note: Callaway is a four-loop plant.) The proposed changes would also revise the TS 3.4.13 conditions and SRs to better clarify the requirements related to primary-to-secondary leakage. Finally, the TS Bases for TSs 3.4.4, 3.4.5, 3.4.6, and 3.4.7 would be revised to eliminate the reference to the SGTSP as the method for ensuring SG operability.

In the licensee's application dated October 27, 2004, changes were proposed to TS Tables 5.5.9-2 and 5.5.9-3 on SG tube and repaired tube inspections to delete requirements to notify the NRC of inspection results. Although these changes were submitted after the application for the replacement SGs, they are contained within the proposed TS changes for the replacement SGs discussed above.

3.2.2 Regulatory Evaluation

3.2.2.1 Current Licensing Basis for SG Tube Integrity

The SG tubes in pressurized-water reactors (PWRs) have a number of important safety functions. These tubes are an integral part of the RCPB and, as such, are relied upon to maintain primary system pressure and inventory. As part of the RCPB, the SG tubes are unique in that they are also relied upon as a heat transfer surface between the primary and secondary systems such that residual heat can be removed from the primary system and are relied upon to isolate the radioactive fission products in the primary coolant from the secondary system. In addition, the SG tubes are relied upon to maintain their integrity to be consistent with the containment objectives of preventing uncontrolled fission product release under conditions resulting from core damage severe accidents. The SG tubes are an important element of the physical barriers designed to contain radioactivity within the plant and, therefore, from the public and the environment.

Title 10 of the *Code of Federal Regulations* (10 CFR) establishes the fundamental regulatory requirements with respect to the integrity of the SG tubing. Specifically, the General Design Criteria (GDC) in Appendix A to 10 CFR Part 50 state that the RCPB shall have “an extremely low probability of abnormal leakage...and of gross rupture" (GDC 14), "shall be designed with sufficient margin" (GDC 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess...structural and leaktight integrity" (GDC 32). To this end, 10 CFR 50.55a specifies that

components which are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (the ASME Code). Section 50.55a further requires, in part, that throughout the service life of a PWR facility, ASME Code Class 1 components meet the requirements, except design and access provisions and pre-service examination requirements, in Section XI, "Rules for Inservice Inspection (ISI) of Nuclear Power Plant Components," of the ASME Code, to the extent practical. This requirement includes the inspection and repair criteria of Section XI of the ASME Code.

In the 1970s, ASME Code Section XI requirements pertaining to ISI of SG tubing were augmented by additional SG tube SRs in the TSs. Paragraph (b)(2)(iii) of 10 CFR 50.55a states that where TS SRs for SGs differ from those in Article IWB-2000 of Section XI of the ASME Code, the ISI program shall be governed by the TSs.

The existing plant TSs include LCOs and accompanying SRs and action statements pertaining to the integrity of the SG tubing. SG operability in accordance with the SGTSP is necessary to satisfy the LCOs governing RCS loop operability, as stated in the accompanying TS Bases. The LCO governing RCS operational leakage includes limits on allowable primary-to-secondary leakage through the SG tubing. Accompanying SRs require verification that RCS operational leakage is within limits every 72 hours by an RCS water inventory balance and that SG tube integrity is in accordance with the SGTSP. The SGTSP requirements are contained in the administrative controls section of the TSs. These administrative controls in the TSs state that the SGs are to be determined operable after the actions required by the SGTSP are completed.

Under the SGTSP requirements, licensees are required to monitor the condition of the SG tubing and to perform repairs, as necessary. Specifically, licensees are required by the TSs to perform periodic ISIs and to remove from service, by plugging, all tubes found to contain flaws with sizes exceeding the acceptance limit, termed "plugging limit" (old terminology) or "tube repair criteria" (new terminology). The frequency and scope of the inspection and the tube repair limits are specified in the TSs.

The tube repair limits in the TSs were developed with the intent of ensuring that degraded tubes (1) maintain factors of safety against gross rupture consistent with the plant design basis (i.e., consistent with the stress limits of the ASME Code, Section III) and (2) maintain leakage integrity consistent with the plant licensing basis while, at the same time, allowing for potential flaw size measurement error and flaw growth between SG tube inspections.

As part of the plant licensing basis, PWR licensees are required to analyze the consequences of postulated DBAs, such as the SG tube rupture (SGTR) and MSLB. These analyses consider the primary-to-secondary leakage through the tubing which may occur during these events and must show that the offsite radiological consequences do not exceed the applicable guidelines of 10 CFR Part 100 for offsite doses, GDC 19 criteria for control room operator doses, or some fraction thereof as appropriate to the accident, or the NRC-approved licensing basis (e.g., a small fraction of the 10 CFR Part 100 guidelines).

3.2.2.2 Compliance with 10 CFR 50.36

In 10 CFR 50.36, NRC established its regulatory requirements related to the content of TSs. This is addressed in Section 2.0 of this SE. The licensee’s application, as supplemented by its

letter dated June 17, 2005, contains proposed LCOs, SRs, and administrative controls involving SG tube integrity. The NRC staff has reviewed the proposed changes to ensure that these changes conform with 10 CFR 50.36 as discussed herein.

3.2.2.3 Background - TS Amendment Request

The current TS requirements for inspection and repair of SG tubing date to the mid-1970s and define a prescriptive approach for ensuring tube integrity. This prescriptive approach involves inspection of the tubing at specified intervals, implementation of specified tube inspection sampling plans, and repair or removal from service by plugging all tubes found by inspection to contain flaws in excess of specified flaw repair criteria. However, as evidenced by operating experience, the prescriptive approach defined in the TSs is not sufficient in-and-of-itself to ensure that tube integrity is maintained. For example, in cases of low to moderate levels of degradation, the TSs only require that 3 to 21 percent of the tubes be inspected, irrespective of whether the inspection results indicate that additional tubes may need to be inspected to reasonably ensure that tubes with flaws that may exceed the tube repair criteria, or that may impair tube integrity are detected. In addition, the TSs (and ASME Code, Section XI) do not explicitly address the inspection methods to be employed for different tube degradation mechanisms or tube locations, nor are the specific objectives to be fulfilled by the selected methods explicitly defined. Also, incremental flaw growth between inspections can, in many instances, exceed what is allowed in the specified tube repair criteria. In such cases, the specified inspection frequencies may not ensure reinspection of a tube before its integrity is impaired. In short, the current TS SRs do not require licensees to actively manage their SG surveillance programs so as to provide reasonable assurance that tube integrity is maintained.

In view of the shortcomings of the current TS requirements, licensees experiencing significant degradation problems have frequently found it necessary to implement measures beyond minimum TS requirements to ensure that adequate SG tube integrity is being maintained. Until the 1990s, these measures tended to be ad hoc. By letter dated December 16, 1997 (Reference 2.1), the Nuclear Energy Institute (NEI) provided NRC with a copy of NEI 97-06, "Steam Generator Program Guidelines," and informed the NRC of the following formal industry position:

> Each licensee will evaluate its existing steam generator program and, where necessary, revise and strengthen program attributes to meet the intent of the guidance provided in NEI 97-06, "Steam Generator Program Guidelines," no later than the first refueling outage starting after January 1, 1999.

The stated objectives of this NEI initiative were to have a clear commitment from utility executives to follow industry SG-related guidelines developed through Electric Power Research Institute (EPRI) to assure a unified industry approach to emerging SG issues and to apply tube integrity performance criteria in conjunction with the performance-based philosophy of the maintenance rule, 10 CFR 50.65. Reference 2.2 is the most recent update to NEI 97-06 available to the NRC staff. NEI 97-06 provides general, high-level guidelines for a programmatic, performance-based approach to ensuring SG tube integrity. NEI 97-06 references a number of detailed EPRI guideline documents for programmatic details.

Subsequently, the NRC staff had extensive interaction with the industry to resolve NRC staff concerns with this industry initiative and to identify needed changes to the plant TSs to ensure that tube integrity is maintained (Reference 2.3).

Ultimately, in consideration of the performance-based objective of this initiative, the NRC staff determined it was not necessary for the NRC staff to formally review or endorse the NEI 97-06 guidelines or the EPRI guideline documents referenced by NEI 97-06. The NRC staff reviewed and approved amended TSs for Joseph M. Farley, Units 1 and 2, which are programmatically consistent with the industry's NEI 97-06 initiative and which ensure that the licensee will implement an SG program that provides reasonable assurance that SG tube integrity will be maintained (Reference 2.4). The TS amendment being requested for Callaway is very similar to the amendments issued to Farley.

As part of the industry's initiative on NEI 97-06, the Westinghouse Owners Group (WOG) submitted generic TSs for the Westinghouse Improved Standard Technical Specifications (ISTS), in NUREG-1431, in Technical Specification Task Force (TSTF) 449, "Steam Generator Tube Integrity," which the NRC approved in Revision 4 in its letter dated May 2, 2005. The licensee had committed in its application, which was submitted prior to the approval of TSTF-449 Revision 4 that it would adopt the NRC-approved revision of TSTF-449. In its supplemental letter dated June 17, 2005, it revised its application such that the proposed changes to the TSs in its letters dated September 17, 2004, and June 17, 2005, would incorporate TSTF-449, Revision 4 in the TSs. The TSTF revised the ISTS in the following sections: TS 3.4.13 on operational leakage, including the definition of leakage; TS 5.5.9 on the SG tube surveillance program; TS 5.6.10 on the SG tube inspection report; and added a new TS 3.4.17 addressing SG tube integrity. The NRC published a "Notice of Availability of Model Application Concerning Technical Specification Improvement to Modify Requirements Regarding Steam Generator Tube Integrity Using the CLIIP [Consolidated Line Item Improvement Process]" in the *Federal Register* on May 6, 2005 (70 FR 24126) for TSTF-449, Revision 4. The licensee's proposed changes to the TSs to adopt TSTF-449, Revision 4 are addressed below in this section of this SE.

3.2.3 Technical Evaluation for SG Tube Integrity

3.2.3.1 TS 3.4.17, "Steam Generator (SG) Tube Integrity"

The current TS establishes an operability requirement for the SG tubing; namely, the tubes shall be determined operable after completion of the actions specified in the SGTSP (i.e., TS 5.5.9). In addition, this surveillance program (and SG operability) is directly invoked by TS 3.4.13 which contains the LCO for RCS operational leakage; however, these TSs do not directly require that SG tube integrity be maintained. Instead, TS 3.4.13 requires implementation of a Steam Generator Program (i.e., the SGTSP discussed above) which is assumed to ensure tube integrity, but, as discussed above, may not ensure SG tube integrity depending on the circumstances of tube degradation at a plant.

To address this shortcoming, the Callaway LAR proposes a new TS 3.4.17, "Steam Generator

(SG) Tube Integrity," which includes a new LCO and accompanying conditions, required actions, completion times, and SRs. The new LCO is applicable in Modes 1, 2, 3, and 4 and requires the following: (1) SG tube integrity shall be maintained and (2) all SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program that is specified in the proposed revised TS 5.5.9. This LCO supplements the LCO in TS 3.4.13 to directly make tube integrity an operational requirement. This is consistent with Criterion 2 of 10 CFR 50.36(c)(2)(ii) because the assumption of tube integrity as an initial condition is implicit

in DBA analyses (with the exception of analysis of a design-basis SGTR where one tube is assumed not to have structural integrity), and is acceptable to the NRC staff.

The proposed SR 3.4.17.1 would require that SG tube integrity be verified in accordance with the Steam Generator Program, which, as stated before, is described in proposed revisions to TS 5.5.9. The required frequency for this surveillance would also be in accordance with the Steam Generator Program, thus meeting the requirements of 10 CFR 50.36(c)(3). The revised TS 5.5.9 would define SG tube integrity in terms of satisfying tube integrity performance criteria for tube structural integrity and leakage integrity as specified therein. SR 3.4.17.1 would replace SR 3.4.13.2 in the RCS operational leakage TS (TS 3.4.13), which provides that tube integrity be verified in accordance with the SG surveillance program as provided in the current TS 5.5.9. The proposed SR 3.4.17.1 improves upon the current SR 3.4.13.2 in that it refers to a program that is directly focused on maintaining SG tube integrity rather than on implementing a prescriptive surveillance program that, as discussed above, may not be sufficient to ensure tube integrity is maintained. The proposed SR 3.4.17.2 would require verification that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program. The tube repair criteria are contained in the program. The required frequency for SR 3.4.17.2 is prior to entering Mode 4 following a SG tube inspection. Based on this, the NRC staff concludes that the proposed SRs 3.4.17.1 and 3.4.17.2 are sufficient to determine whether the proposed LCO 3.3.17.1 is met. Based on this, the NRC staff further concludes that the SRs meet the requirements of 10 CFR 50.36(c)(3) and are, therefore, acceptable.

The licensee has proposed conditions, required actions, and completion times for the new LCO 3.4.17, as shown below in Table 1 on the following page. The proposed TS 3.4.17 allows separate condition entry for each SG tube.

TABLE 1

LCO 3.4.17 CONDITIONS

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

Should the SGTSP find that SG tube integrity is not being maintained, Required Actions B.1 and B.2 would require that the plant be in Mode 3 within 6 hours and MODE 5 within 36 hours, respectively. These required actions and completion times are consistent with (1) the general requirements in TS 3.0.3 for failing to meet an LCO and (2) the requirements of TS 3.4.13 when the LCO on primary-to-secondary leakage rate is not met. Based on this, the NRC staff concludes that these required actions and completion times provide adequate remedial measures should SG tube integrity be found not to be maintained and are, therefore, acceptable.

Condition A of proposed TS 3.4.17 addresses the condition where one or more tubes satisfying the tube repair criteria are inadvertently not plugged in accordance with the Steam Generator Program. Under TS 3.4.17 Required Action A.1, the licensee would be required to verify within 7 days that tube integrity of the affected tubes is maintained until the next inspection. The accompanying TS Bases state that the tube integrity determination would be 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 inspection. The NRC staff notes that details of how this assessment would be performed are not included in proposed TS 3.4.17 or TS 5.5.9. The NRC staff finds this to be consistent with having performance-based requirements, finds that the performance criteria (i.e., performance objectives) for assessing tube integrity are clearly defined (in proposed TS 5.5.9), and finds that it is appropriate that the licensee has the flexibility to determine how best to perform this assessment based on what information is and is not available concerning the circumstances of the subject flaw. The proposed 7 days allowed to complete the assessment ensures that the risk increment associated with operating with tubes in this condition will be very small. Should the assessment reveal that tube integrity cannot be maintained until the next scheduled inspection or if the assessment is not completed in 7 days, TS 3.4.17 Condition B applies, leading to Required Actions B.1 and B.2, which are evaluated above. Finally, if Required Action A.1 successfully verifies that tube integrity is being maintained until the next inspection, Required Action A.2 would require that the subject tube be plugged in accordance with the SGTSP prior to entering Mode 4 after the next refueling outage or SG tube inspection. Based on the above, the NRC staff concludes that the proposed LCO, and accompanying conditions and required actions, related to failure to plug a tube that satisfies the tube repair criteria are acceptable.

The licensee has proposed administrative changes to the TS Title page and identified changes to the TS Bases in support of the proposed new TS 3.4.17. Changes to the TS Bases are controlled by TS 5.5.14, "Technical Specification (TS) Bases Control Program," and, as stated in TS 5.5.14, changes to the TS Bases are controlled under the criteria in 10 CFR 50.59. Based on its review of the identified changes to the TS Bases, the NRC staff finds that it has no disagreement with the identified changes to the TS 3.4.17 Bases.

3.2.3.2 SG Operability

TS 3.4.4, "RCS Loops - Modes 1 and 2," TS 3.4.5, "RCS Loops - Mode 3," and TS 3.4.6, "RCS Loops - Mode 4," are not being changed by this amendment. The TS Bases for TSs 3.4.4, 3.4.5, and 3.4.6 define an operable RCS Loop as consisting of an operable reactor coolant pump (RCP) in operation providing forced flow for heat transport and an operable SG in accordance with the SGTSP. The TS Bases for TS 3.4.7 define an operable SG as a SG that can perform as a heat sink via natural circulation when it has an adequate water level and is operable in accordance with the Steam Generator Program. Although the TS Bases are

controlled by TS 5.5.14 and, therefore, changes to the TS Bases are under the criteria of 10 CFR 50.59, the licensee has identified that it will delete the phrases, "in accordance with the Steam Generator Tube Surveillance Program," from the TS Bases for TSs 3.4.4, 3.4.5, 3.4.6, and 3.4.7.

With the deletion of these phrases, an operable SG will be defined under the definition of operable - operability in TS 1.1, which is stated below:

> A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

The NRC staff has reviewed the identified TS Bases changes discussed above. The current TS Bases refer to the SGTSP for the requirements of an operable SG. The SGTSP provided the controls for the ISI of SG tubes that was intended to ensure that the structural integrity of this portion of the RCS is maintained. Using the definition of operable - operability expands the definition of an operable SG beyond maintaining structural integrity and is, therefore, acceptable.

3.2.3.3 Proposed Administrative Controls TS 5.5.9, "Steam Generator Program"

The administrative controls in the proposed TS 5.5.9 will replace the existing TS 5.5.9. The current TS 5.5.9 defines a prescriptive strategy for ensuring SG tube integrity consisting of tube inspections performed at specified intervals, with a specified inspection scope (tube inspection sample sizes), and with a specified tube acceptance limit for degraded tubing, termed “tube repair criterion,” beyond which the affected tubes must be plugged. The proposed TS 5.5.9 incorporates a largely performance-based strategy for ensuring SG tube integrity, requiring that a Steam Generator Program be established and implemented to ensure tube integrity is maintained. The proposed specification contains only a few details concerning how this is to be accomplished, the intent being that the licensee will have the flexibility to determine the specific strategy to be employed to satisfy the required objective of maintaining tube integrity. However, as evaluated below, the NRC staff concludes that the proposed TS 5.5.9 provides reasonable assurance that the Steam Generator Program will maintain tube integrity.

The licensee's identified TS BASES for TS 3.4.17 state that NEI 97-06, and its referenced EPRI guideline documents, will be used to establish the content of the SGTSP. The guidelines are industry-controlled documents and a licensee's SGTSP may deviate from these guidelines. Except as may be specifically invoked by the TSs, the NRC staff’s evaluation herein takes no credit for any of the specifics in these guidelines.

3.2.3.3.1 Performance Criteria for SG Tube Integrity

The proposed TS 5.5.9 would require SG tube integrity to be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage as specified therein.

The NRC staff's criteria for evaluating the acceptability of these performance criteria are that meeting these criteria is sufficient to ensure that tube integrity is within the plant licensing basis and that meeting these criteria, in conjunction with implementation of the Steam Generator Program, ensures no significant increase in risk in operating with the SGs. These performance criteria must also be evaluated in the context of the overall Steam Generator Program such that if the performance criteria are inadvertently exceeded, the consequences will be tolerable before the situation is identified and corrected. In addition, the performance criteria must be expressed in terms of parameters that are measurable, directly or indirectly.

3.2.3.3.1.1 Structural Integrity Criteria

The proposed structural integrity criteria is as follows:

> All inservice steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, cooldown, and all anticipated transients included in the design specification) and design basis accidents. This includes maintaining 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 design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading considerations associated with 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 differential pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

The NRC staff has evaluated this proposed criteria for consistency with the safety factors embodied in the current licensing basis for Callaway, specifically, the safety factors embodied in the TS SG tube repair criteria. The SG tube repair criterion typically specified in plant TSs is 40 percent of the initial tube wall thickness. This criterion is typically applicable to all tubing flaws found by inspection, except for certain flaw types at certain locations for which less restrictive repair criteria may be applicable (as specified in the TSs) and for certain sleeve repairs for which a more restrictive tube repair criterion may be specified.

In 1976, the NRC staff prepared Regulatory Guide (RG) 1.121 (Draft), "Basis for Plugging Degraded PWR Steam Generator Tubes," (Reference 2.5), which described a technical basis for the development of SG tube repair criteria. This draft RG was issued for public comment, but was never finalized. Although not finalized, the RG is generally cited in licensee and

industry documentation as the bases for the SG tube repair criteria in plant TSs. The draft RG includes the following with respect to safety factors:

1. Degraded tubing should retain a factor of safety against burst of not less than three under normal operating conditions.

2. Degraded tubing should not be stressed beyond the elastic range of the tube material during the full range of normal reactor operation. The draft regulatory guide also states that loadings associated with normal plant conditions, including startup, operation in the power range, hot standby, and cooldown, as well as all anticipated transients (e.g., loss of electrical load, loss of off-site power) that are included in the design specifications for the plant, should not produce a primary membrane stress in excess of the yield stress of the tube material at operating temperature.

3. Degraded tubes should maintain a margin of safety against tube failure under postulated accidents consistent with the margin of safety determined by the stress limits specified in NB-3225 of Section III of the ASME Code. Note, NB-3225 specifies that the rules in Appendix F of Section III may be used for evaluating these loadings.

In Item 1, the “safety factor of three” criterion stems from Section III of the ASME Code, which, in part, limits primary membrane stress under design conditions to one third of the ultimate strength. The proposed structural integrity criterion would limit application of the “safety factor of three” criterion to only those pressure loadings existing during normal full power, steady-state operating conditions. Differential pressures under this condition are plant-specific, ranging from 1250 psi to 1500 psi (Reference 2.6). However, differential pressure loadings can be considerably higher during normal operating transients, ranging to between 1600 psi to 2150 psi during plant heatup and cooldown transients. Given a factor of safety equal to three under normal full power conditions, the factor of safety during heatups and cooldowns can be as low as about two. The industry stated in a white paper (Reference 2.6) that it was not the intent of the 40 percent depth-based tube repair criterion to ensure a factor of safety of three for operating transients such as heatups and cooldowns. The industry stated that maintaining a safety factor of three for such transients would lead to tube repair criteria less than the standard 40 percent criterion for many plants. The NRC staff has independently performed calculations that support the industry’s contention that applying the “safety factor of three” criterion to the full range of normal operating conditions would lead to tube repair criteria more restrictive than the 40 percent criterion, which the NRC staff has accepted since the 1970s. The NRC staff concludes that the “safety factor of three” criterion for application to normal full power, steady-state pressure differentials, as proposed by the licensee and the industry, is consistent with the safety margins implicit in existing TS SG tube repair criteria and, thus, is consistent with the current licensing basis of plants.

Item 2 above is often referred to as the "no yield" criterion. The purpose of this criterion is to prevent permanent deformation of the SG tube to assure that degradation of the tube will not occur due to mechanical effects of the service condition. This is consistent with ASME Code, Section III, stress limits, which serve to limit primary membrane stress to less than yield. The proposed structural integrity criteria do not include this “no yield” criterion. The industry states in its white paper (Reference 2.6) that, if a tube satisfies the “safety factor of three” criterion at full power operating pressure differentials, the tube will generally satisfy the "no yield" criterion for the operating transient (e.g., heatup and cooldown) pressure differentials. The white paper acknowledges that this may not be true for all plant-specific conditions and material properties. For this reason, NEI 97-06, Revision 1, and the EPRI Steam Generator Integrity Assessment Guidelines state that, in addition to meeting the safety factor of three for normal steady-state

operation, the integrity evaluation shall verify that the primary pressure stresses do not exceed the yield strength for the full range of normal operating conditions. The white paper, which has been incorporated as part of the EPRI Steam Generator Integrity Assessment Guidelines, recommends that this be demonstrated for each plant using plant-specific conditions and material properties.

The NRC staff concurs that the "no yield" criterion does not need to be specifically spelled out in a TS definition of SG tube structural integrity criteria. The NRC staff finds that the appropriate focus of the TS criteria should be on preventing burst. The NRC staff calculations confirm that the proposed “safety factor of three” criterion above bounds or comes sufficiently close to bounding the “no yield” criterion for most of the cases investigated. This is not an absolute. For example, for once-through SGs (OTSGs), the NRC staff noted a case where elastic hoop stress in a uniformly thinned tube could exceed the yield strength by 20 percent under heatup and cooldown conditions and still satisfy the "safety factor of three" criterion against burst under normal steady state, full power operating conditions. Such a tube would still retain a safety factor of two against burst under heatup and cooldown conditions. The amount of plastic strain induced would be limited to between 1 and 2 percent based on typical strain hardening characteristics of the material. This is quite small compared to cold working associated with fabrication of tube u-bends and tube expansions. Operating experience shows that this level of plastic strain (i.e., permanent strain caused by exceeding the yield stress) has not adversely affected the stress corrosion cracking resistance of OTSG tubing relative to that expected for non-plastically strained tubing. Thus, the NRC staff concludes that the "safety factor of three" criterion is sufficient to limit plastic strains to values that will not contribute significantly to degradation of the tubing and that the “no yield’ criterion need not be specifically spelled out in the SG tube structural integrity performance criteria in the TSs. Based on this, the NRC staff concludes that the proposed "safety factor of three" is acceptable.

The proposed safety factor of 1.4 against burst applied to design-basis primary-to-secondary pressure differentials derives from the 0.7 times ultimate strength limit for primary membrane stress in the ASME Code, Appendix F, F-1331.1(a). This criterion is consistent with the stress limit criteria used to develop the standard 40 percent tube repair criteria in the TSs and with the safety factor criteria used in the derivation of alternate tube repair criteria in plant TSs, such as the voltage based criteria for outer-diameter stress corrosion cracking. Thus, the criterion is consistent with the current plant licensing basis and is, therefore, acceptable.

Apart from differential pressure loadings, other types of loads may also contribute to burst. Examples of such loads include bending moments on the tubes due to flow induced vibration, earthquake, and loss-of-coolant accident (LOCA) rarefaction waves. For OTSGs, axial loads are induced in the tubes due to (1) pressure loadings acting on the SG shell and tube sheets, and (2) differential thermal expansion between the tubes and the SG shell. Such non-pressure loads generally produce negligible primary stress during normal operating conditions from the standpoint of influencing burst pressure. In general, such non-pressure loads may be more significant under certain accident loadings depending on SG design, flaw location, and flaw orientation. Such non-pressure sources of primary stress under accident conditions were explicitly considered in the development of the 40-percent tube repair criterion relative to ASME Code, Appendix F, stress limits.

The proposed structural criterion requires that, apart from the safety-factor requirements applying to pressure loads, additional loads associated with DBAs, or combination of accidents

in accordance with the plant design and licensing basis, shall also be evaluated to determine whether these loads contribute significantly to burst or collapse. The NRC staff notes that examples of such additional loads include bending moments during LOCA, MSLB, or safe shutdown earthquake (SSE) and axial, differential thermal loads. The reference to “combination of accidents” refers to the fact that the design and licensing basis for many plants is that DBAs, such as LOCA and MSLB, are assumed to occur concurrently with the SSE. Whereas “burst” is the failure mode of interest where primary-to-secondary pressure loads are dominant, “collapse” is a potential limiting failure mode (although an unlikely one, according to industry based on a recent study (Reference 2.7)) for loads other than pressure loads. The word “collapse” refers to the condition where the SG tube is not capable of resisting further applied loading without unlimited displacement. Although the occurrence of a collapsed SG tube or tubes would not necessarily lead to perforation of the tube wall, the consequences of tube collapse have not been analyzed and, thus, the NRC staff finds it both appropriate and conservative to ensure there is a margin relative to such a condition.

Where non-pressure loads are determined to significantly contribute to burst or collapse, the proposed structural criterion requires that such loads 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 a safety factor of 1.0 on axial secondary loads. The 1.2 safety factor for combined primary loads was derived from the ratio of burst or collapse load divided by allowable load from ASME Code for faulted conditions. Burst or collapse load was assumed to be equal to the material flow stress, assuming ASME Code minimum yield and ultimate strength values and a flow stress coefficient of 0.5. Allowable load was determined from ASME Code, Section III, Appendix F, F-1331.3.a, which defines an allowable primary membrane plus bending load for service level d (faulted) conditions. The NRC staff finds this 1.2 safety factor acceptable. The proposed 1.0 safety factor for axial secondary loads goes beyond what is required by the design basis in Section III of the ASME Code, since Section III assumes that a one-time application of such a load cannot lead to burst or collapse. However, this is not necessarily the case for tubes with circumferential cracks. The proposed safety factor of 1.0 is conservative for loads that behave as secondary since it ignores the load relaxation effect associated with axial yielding before tube severance (burst) occurs.

Apart from being consistent with the current licensing basis, NRC risk studies have indicated that maintaining the performance criteria safety factors is important to avoiding undue risk, particularly risk associated with severe accident scenarios involving a fully pressurized primary system and depressurized secondary system and where the SG tubes may heat to temperatures well above design basis values, significantly reducing the strength of the tubes (Reference 2.8).

Based on the above, the NRC staff concludes that the proposed SG tube structural performance criteria is consistent with the margins of safety embodied in existing plant licensing bases. Therefore, exceeding these criteria is not likely to lead to consequences that are intolerable, provided that such an occurrence is infrequent and that, if it occurs, it is promptly detected and corrected so as to ensure that risk is limited, because margins of safety remain. Specifically, structural margins can be directly demonstrated through in situ pressure testing or can be calculated from burst prediction models using as input flaw size measurements obtained by inspection. Even if a SG tube should degrade to the point of rupture under normal operating conditions, such an occurrence is an analyzed condition with reasonable assurance that the radiological consequences of such an event will be acceptable. Finally, the structural

performance criterion is expressed in terms of parameters that are measurable. Therefore, the NRC staff concludes that the proposed SG tube structural performance criteria are acceptable.

3.2.3.3.1.2 Accident Leakage Criterion

The licensee's proposed accident induced leak rate criterion is as follows:

> 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. Leakage is not to exceed 1 gpm [gallons per minute] total for all four SGs.

This performance criterion for accident induced leak rate is consistent with leak rates assumed in the plant licensing basis accident analyses for purposes of demonstrating that the consequences of DBAs meet the guidelines in 10 CFR Part 100 for offsite doses, GDC 19 for control room operator doses, or some fraction thereof as appropriate to the accident, or the NRC-approved licensing basis (e.g., a small fraction of these limits). This criterion does not apply to design-basis SGTR accidents for which leakage corresponding to a postulated double ended rupture of a tube is assumed in the analysis. The proposed criterion ensures that, from the standpoint of accident induced leakage, the plant will be operated within its analyzed condition and is acceptable.

For certain severe accident sequences involving high primary side pressure and a depressurized secondary system (i.e., the “high-dry” condition), primary-to-secondary leakage may lead to more heating of the leaking SG tube than would be the case were it not leaking, thus increasing the potential for failure of that tube and a consequent large early release. The proposed 1 gpm limit on total leakage from all SGs during DBAs (other than a SGTR event) ensures that the potential for induced leakage during severe accidents will be maintained at a level which will not increase risk.

Exceeding this criterion is not likely to lead to intolerable consequences, provided that such an occurrence is infrequent and that such an occurrence, if it occurs, is promptly detected and corrected so as to ensure that risk is minimized, because margins of safety remain. It should be noted that the criterion applies to leakage that could be induced by an accident in the unlikely event that such an accident occurs. Finally, the accident leakage performance criterion is expressed in terms of parameters that are measurable, both directly and indirectly. Specifically, structural margins can be directly demonstrated through in situ pressure testing or can be calculated using leakage prediction models using flaw size measurements obtained by ISI as input.

Based on the foregoing, the NRC staff concludes that the proposed accident leakage criterion is acceptable.

3.2.3.3.1.3 Operational Leakage Criterion

The proposed TS 5.5.9 states that the operational leakage performance criterion is specified in LCO 3.4.13, “RCS Operational Leakage,” which is being changed by this amendment. The

licensee has proposed to delete the 600 gpd limit for total primary-to-secondary leakage through all the SGs, but keep the 150 gpd limit for total primary-to-secondary leakage through any one SG. Given the remaining TS LCO 3.4.13 limit of 150 gpd primary-to-secondary leakage through any one SG, a separate performance criterion for operational leakage is unnecessary for ensuring prompt shutdown should the limit be exceeded. However, operational leakage is an indicator of tube integrity performance, though not a direct indicator. It is the only indicator that can be monitored while the plant is operating. Maintaining leakage to within the limit provides added assurance that the structural and accident leakage performance criteria are being met. Thus, the NRC staff believes that inclusion of the TS leakage limit among the set of tube integrity performance criteria is appropriate from the standpoint of completeness and is, therefore, acceptable.

3.2.3.3.2 Condition Monitoring Assessment

The proposed TS 5.5.9 would require that the SGTSP include provisions for condition monitoring assessments as follows:

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

The NRC staff finds that the proposed requirement for condition monitoring assessments addresses an essential element of any performance-based strategy, namely, the need to monitor performance relative to the performance criteria. Confirmation that the SG tube integrity criteria are met would confirm that the overall programmatic goal of maintaining tube integrity has been met to that point in time. However, failure to meet the tube integrity criteria would be indicative of potential shortcomings in the effectiveness of the licensee’s SGTSP and the need for corrective actions relative to the program to ensure that SG tube integrity is maintained in the future. Failure to meet either the structural or accident leakage performance criterion would be reportable pursuant to 10 CFR 50.72 and 50.73 in accordance with guidelines in Reference 2.9. In addition, the NRC Regional Office would follow up on such an occurrence as appropriate consistent with the NRC Reactor Oversight Program (ROP) (Reference 2.10) and the risk significance of the occurrence.

The proposed TS 5.5.9 would require that condition monitoring be performed at each ISI of the tubing. The NRC staff’s evaluation of the proposed frequency of ISI is addressed in Section 3.2.3.3.3 below of this SE.

3.2.3.3.3 ISI

The proposed TS 5.5.9 would require that the SGTSP include periodic SG tube inspections. This proposal includes a new performance-based requirement that the inspection scope,

inspection methods, and inspection intervals shall be established to ensure that SG tube integrity is maintained until the next inspection. This is a performance-based requirement that complements the requirement for condition monitoring (addressed in Section 3.2.3.3.2 of this SE) from the standpoint of ensuring SG tube integrity is maintained. The requirement for condition monitoring is backward looking in that it is intended to confirm that tube integrity has been maintained up to the time the assessment is performed. The ISI requirement, by contrast, is forward looking. It is intended to ensure that tube inspections in conjunction with plugging of tubes are performed such as to ensure that the performance criteria will continue to be met at the next SG inspection. This would be followed again by condition monitoring at the next SG inspection to confirm that the performance criteria were in fact met.

With respect to scope and methods of inspection, the proposed specification would also require that the number and portions of tubes inspected and method of inspection be performed with the objective of detecting flaws of any type (for example, 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. Furthermore, 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.

The NRC staff finds that this proposal concerning the scope and methods of inspection includes a number of improvements relative to the current specification. The current specification requires that SG tube inspections be conducted from the point of entry on the hot leg side completely around the u-bend to the top support plate on the cold leg side. Thus, the current TSs do not require inspection of SG tubing on the cold leg side up to the uppermost support plate elevation. Operating experience demonstrates that the entire length of tubing is subject to various forms of degradation. The proposed specification addresses this issue by requiring cold leg as well as hot leg inspections. Also, the proposed requirement clarifies the licensee's obligation under existing TSs and 10 CFR 50, Appendix B, to employ inspection methods capable of detecting flaws of any type that the licensee believes may potentially be present anywhere along the length of the tube based on a degradation assessment.

The proposed specification specifically excludes the SG tubesheet welds and the tube ends beyond the welds from the inspection requirements therein. The NRC staff finds this to be consistent with current actual plant practice and, thus, to be acceptable. The tube ends beyond the tube-to-tubesheet welds are not part of the primary RCS pressure boundary.

The proposed specification would replace current specific requirements pertaining to the number of SG tubes to be inspected at each inspection, in part, with a requirement that is performance based; that is, the number and portions of tubes inspected (in conjunction with other elements of inspection) shall be such as to ensure that tube integrity is maintained until the next inspection. The current minimum SG tube sampling requirement for an SG inspection is 3 percent of the SG tubing at the plant. The purpose of this initial sample is to determine whether active degradation is present and whether there is a need to perform additional inspection sampling. Actual industry practice, consistent with NEI 97-06 and the EPRI Examination Guidelines, Revision 6, typically involves initial inspection samples of at least 20 percent. If moderate numbers of SG tubes (i.e., category C-2 as defined in the current TSs) are found to contain flaws, the current TSs requires that an additional 6 to 18 percent of the

tubes be inspected. In many cases this requirement is very non-conservative since no consideration is given to whether uninspected SG tubes may contain flaws that could challenge the tube integrity performance criteria prior to the next inspection. Current industry practice and the industry guidelines involve substantially higher levels of sampling under these circumstances. This practice has been motivated by a desire to minimize forced outages as well as by the requirement to ensure SG tube integrity. The NRC staff finds, therefore, that current TS sampling requirements do not drive actual sampling programs in the field for plants with low to moderate levels of tube degradation, and that for moderate levels of tube degradation the current TS requirements do not ensure adequate levels of sampling to ensure tube integrity will be maintained. The proposed specification addresses this shortcoming by requiring that inspection scope be consistent with the overall performance objective that tube integrity be maintained until the next SG inspection.

For SGs with high levels of degradation (i.e., category C-3 as defined in current TSs), the current TS requires that the inspections be expanded to include 100 percent of the tubes in the affected SG. This requirement is conservative in cases where the active degradation is confined to specific groups of tubes in the SG. This requirement does drive actual sampling programs in the field since industry guidelines would permit 100 percent sampling to be confined to those portions of the SG bounding the region where the degradation has been found to be active. The proposed specification would give licensees the flexibility to implement less than 100 percent inspection of the SG in these cases, provided it is consistent with the performance-based objective of ensuring that tube integrity is maintained until the next SG inspection.

Overall, the NRC staff concludes that the proposed specification ensures that the licensee will implement inspection scopes consistent with the overall objective that SG tube integrity be maintained. To meet this requirement, it will be necessary to inspect tubes that may contain flaws that may challenge the SG tube integrity performance criteria prior to the next inspection. The proposed specification gives the licensee the flexibility to define an inspection scope that ensures that this objective is met while avoiding any unnecessary inspections.

With respect to frequency of inspection, the current specification requires that SG inspections be performed every 24 calendar months. This frequency may be extended to once every 40 calendar months if the previous two inspections revealed only low-level degradation (i.e., category C-1 results as defined in the TSs). The inspection frequency is required to revert from the 40 calendar months to 20 calendar months if an extensive level of degradation (i.e., category C-3 results as defined in the TS) is observed during the most recent inspection. Except in cases where extensive degradation (i.e., category C-3) is found in any SG, SGs may be inspected on a rotating basis at each inspection. Thus, for 4-loop plants performing SG inspections at 24-month intervals, intervals for an individual SG may range up to 96 months. Similarly, for 4-loop plants performing SG inspections at 40-month intervals, intervals for an individual SG may range up to 160 months. However, these prescriptive requirements bear no direct relationship to the overall objective of ensuring that SG tube integrity is maintained. These requirements apply irrespective of the flaw detection and sizing performance of the inspection methods utilized and the rate at which flaws may be growing in the subject SGs. These requirements do not ensure that flawed tubing remaining in service following an SG tube inspection and the incremental flaw growth that may take place prior to the next inspection are within the allowances provided for by the TS SG tube repair limit or that tube integrity will be maintained prior to the next inspection.

Plants operating with their originally installed SGs have typically inspected each SG at each refueling outage, which typically occur at intervals of less than 24 calendar months. The vast majority of these SGs contained alloy 600 mill annealed (MA) tubing, which quickly became moderately to extensively degraded (i.e., category C-2 or C-3 as defined in the current TSs) such that the TSs would not allow longer intervals. The 24-month inspection interval requirement usually proved sufficient in maintaining SG tube integrity. Nonetheless, there have been instances where licensees have performed mid-cycle inspections to ensure SG tube integrity would be maintained.

However, many SGs with alloy 600 MA tubing have been replaced with SGs with alloy 600 thermally treated (TT) or alloy 690 TT tubing which have proven to be much more resistant to stress corrosion cracking (SCC) than alloy 600 MA tubing. This includes Callaway which has replacement SGs, which have alloy 690 TT tubing. Based on early low levels of degradation, some of the plants with replacement SGs are taking advantage of the longer inspection intervals permitted by the TSs.

Under the proposed TS 5.5.9, the required frequency of inspection in conjunction with inspection scope and inspection methods shall be such as to ensure that tube integrity is maintained until the next SG inspection. This addresses existing shortcomings in the current requirements in TSs in that it requires that the inspection frequency be part of a management strategy aimed at ensuring tube integrity. The identified TS 3.4.17 Bases state that inspection frequency will be determined, in part, by operational assessments which utilize additional information on existing degradation and flaw growth rates to determine an inspection frequency that provides reasonable assurance that the tubing will meet the SG tube performance criteria at the next SG inspection.

The NRC staff also notes, however, that any assessment or projection of the future condition of the SG tubing based on the existing condition of the tubing and anticipated flaw growth rates can involve significant uncertainty that may be difficult to conservatively and reliably bound. For this reason, proposed TS 5.5.9 supplements the performance-based requirement concerning inspection frequencies with a set of prescriptive requirements that provide added assurance that SG tube integrity will be maintained.

The proposed prescriptive requirements include a requirement that 100 percent of the tubes in each SG be inspected at the first refueling outage following SG replacement. The required scope of this inspection is substantially more restrictive than the current requirement, which

requires a 3 percent sample of the total SG tube population and requires inspection of only two of the four SGs.

For Callaway, the proposed specification would require that 100 percent of the tubes be inspected at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months (EFPM), with the first sequential period being considered to begin at the time of the first ISI of the SGs following SG replacement. A plant operating at full power for one month has gone through 1 EFPM. This sliding scale is intended to address the increased potential for the initiation of SCC over time. In addition, the licensee would be required to inspect 50 percent of the SC tubes by the refueling outage nearest the mid-point of the period and the remaining 50 percent by the refueling outage nearest the end of the period. However, no SG shall operate for more than 72 EFPM or three refueling outages (whichever is less) without being

inspected.

Regardless of the type of tubing, if crack indications are found in any tube, the proposed specification requires that the next inspection for each SG for the degradation mechanism causing the crack indication shall not exceed 24 EFPM or one refueling outage (whichever is less). As a point of clarification, the proposed requirements stipulate that 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 a crack, then the indication need not be treated as such.

These proposed prescriptive requirements, in total, cannot be described simplistically as being more restrictive or less restrictive than current requirements. They are a quite different set of requirements, being generally more restrictive for SGs with low-to-moderate levels of degradation (i.e., categories C-1 to C-2 as defined in current TS) to somewhat less restrictive for plants with extensive levels of degradation other than cracks. As previously noted, management of SCC mechanisms relative to the performance criteria poses a particular challenge compared to other degradation mechanisms. The proposed requirement to limit inspection intervals to one refueling outage to address any cracking mechanism found to be present in the SGs is a substantially more restrictive requirement than current TS requirements that apply for plants with low to moderate levels of cracked tubes and for practical purposes leads to the same inspection frequency (every refueling outage) as would be required under current TS requirements for plants with moderate to extensive levels of cracked tubes.

The proposed prescriptive requirements relating to inspection frequency have been developed based on qualitative engineering considerations and experience. This reflects the following: (1) the improved SCC resistance of alloy 690 TT tubing relative to alloy 600 TT tubing, and particularly relative to alloy 600 MA tubing; (2) the potential for cracking which increases with increasing time in service; and (3) the particular challenges associated with the management of SCC with respect to satisfying the SG tube integrity performance criteria. The proposed prescriptive requirements are intended primarily to supplement the performance-based requirement that inspection frequency in conjunction with inspection scope and methods be such as to ensure that SG tube integrity is maintained. This performance-based requirement must be satisfied in addition to the prescriptive requirements. The NRC staff concludes that the proposed performance-based requirement, in conjunction with the proposed prescriptive requirements, represents a significantly more effective strategy for ensuring SG tube integrity

than that provided by current TS requirements, and will serve to ensure that tube integrity is maintained between SG inspections.

3.2.3.3.4 Tube Repair Criterion

Revised TS 5.5.9 would retain the current depth-based TS SG tube repair criterion (termed the plugging limit in current TSs) requirement. Specifically, the proposed specification would require that SG tubes found by ISI to contain flaws with a depth equal to or exceeding 40 percent of the nominal tube wall thickness be plugged. This criterion is consistent with the SG tube integrity performance criteria in that flaws not exceeding the tube repair criterion satisfy the performance criteria with allowances for flaw size measurement error and incremental crack growth between inspections. However, the revised TS 5.5.9 would delete currently specified SG tube repair limits for laser welded sleeves and Electrosleeves, since

currently specified provisions for these types of repairs are also deleted from this revised specification. The previously authorized tube repair methods for the current SGs are not applicable to the replacement SGs. The replacement SGs do not contain welded sleeves or Electrosleeves.

The TS SG tube repair criterion provides added assurance that tube integrity will be maintained, given the performance-based strategy that is also to be followed under the proposed specification. The inclusion of tube repair criterion as part of the proposed specification also ensures that the NRC staff has the opportunity to review any risk implications should the licensee propose a license amendment for alternate SG tube repair criteria, in conjunction with alternate tube integrity performance criteria, in the future.

3.2.3.3.5 Monitoring of Operational Primary-to-Secondary Leakage

Proposed TS 5.5.9 would require that the Steam Generator Program include provisions for monitoring primary-to-secondary leakage. The NRC staff's evaluation of this proposal is included as part of the NRC staff's evaluation of the proposed change to TS 3.4.13 in Section 3.2.3.5 of this SE.

3.2.3.4 TS 5.6.10, "Steam Generator Tube Inspection Report"

The proposed TS 5.6.10 would revise the current requirements to report the results of the ISI of SG tubes within 12 months of the inspection and include (1) the number and extent of the tubes inspected, (2) the location and percent of wall thickness penetration for each indication, and (3) identification of tubes plugged. The proposed requirement would be to submit a report within 180 days of entry into Mode 4 following a SG inspection and include the following:

- The scope of the inspections performed in each SG,
- active degradation mechanisms found,
- non-destructive examination techniques used for each degradation mechanism,
- location, orientation (if linear), and measured sizes (if available) of service induced indications,
- number of tubes plugged during the inspection outage for each active degradation mechanism,
- total number and percentage of tubes plugged to date, and
- the results of condition monitoring, including the results of tube pulls and in-situ testing.

This revised reporting requirement is a more comprehensive requirement than the current 12-month report and will enhance the NRC staff's ability to monitor the kinds of inspections being performed, the extent and severity of each active degradation mechanism, degradation trends (stable or getting worse), and the degree of challenge faced by the licensee in maintaining SG tube integrity. The longer 180-day reporting requirement is adequate given that, if the Steam Generator Program should fail to maintain SG tube integrity as indicated by condition monitoring, which is discussed in Section 3.2.3.3.2 of this SE, this would be promptly

reportable in accordance with 10 CFR 50.72 and Reference 2.9 allowing the NRC staff to engage in any prompt follow-up activities that it determines to be necessary.

The specification currently also requires that the numbers of tubes plugged in each SG be reported to the NRC within 15 days following completion of the program. In addition, the specification currently requires that inspection results falling into Category C-3 shall be reported to the NRC within 30 days and prior to the resumption of plant operation and that the report include a description of the investigations conducted to determine the cause of the tube degradation and corrective measures taken to prevent recurrence. The proposed amendment would delete both of these requirements. The NRC staff finds deletion of these requirements to be acceptable because neither the number of tubes plugged nor the finding of Category C-3 results (i.e., 10 percent of the tubes inspected contain degradation or 1 percent of the tubes inspected satisfy the tube repair criteria) have any real bearing on whether tube integrity is being maintained because the past reporting requirements were on the number of tubes and not on whether the tubes have sufficient safety margins.

The NRC staff also notes that the proposed amendment would delete the definition of inspection results categories in the current TSs. If the SG program is effectively maintaining tube integrity, tubes found to be degraded or to be pluggable will also satisfy the tube integrity performance criteria. The regulation at 10 CFR 50.72, in conjunction with Reference 2.9, require that the NRC staff be promptly notified in the event that the tube integrity performance criteria are not met. The NRC staff would have the opportunity under the NRC ROP to follow up on such an occurrence as warranted. A Licensee Event Report is required by 10 CFR 50.73 to be issued within 60 days of the finding that addresses, in part, the degraded condition of the SG tube(s) and the corrective measures being taken.

Based on the above, the NRC staff concludes that the proposed revisions to the reporting requirements in TS 5.6.10 are acceptable.

3.2.3.5 TS 3.4.13, "RCS Operational Leakage"

The licensee proposed several changes to the LCO, LCO required actions, and SRs for TS 3.4.13. These changes include administrative changes to the LCO, LCO required action statements, and SRs. The proposed changes are the following:

- Add the word "and" to the end of LCO 3.4.13.c, which is addressed in Sections 3.2.3.3.1.3 and 3.2.3.5.1 of this SE;
- Delete LCO 3.4.13.d, which is addressed in Sections 3.2.3.3.1.3 and 3.2.3.5.1 of this SE;
- Replace "SG" in re-numbered LCO 3.4.13.d with "steam generator (SG)," which is addressed in Sections 3.2.3.3.1.3 and 3.2.3.5.1 of this SE;
- Re-number the current LCO 3.4.13.e as LCO 3.4.13.d, with the deletion of the existing LCO 3.4.13.d;
- Add the word "operational" to make the phrase "RCS operational LEAKAGE" in Condition A;

- Add "or primary-to-secondary LEAKAGE" to the end of Condition A, wherein Condition A will state “RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary-to-secondary LEAKAGE”;

- Expand Condition B to also include "OR Primary-to-Secondary LEAKAGE not within limit," which is addressed in Section 3.2.3.5.2 of this SE;

- Add a Note 2 to SR 3.4.13.1 that states "Not applicable to primary-to-secondary LEAKAGE," change the existing note to Note 1, and change "Note" to "Notes," which is addressed in Section 3.2.3.5.3 of this SE;

- Revise SR 3.4.13.1 to state "Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance," which is addressed in Section 3.2.3.5.3 of this SE; and

- Revise SR 3.4.13.2 to state "Verify primary to secondary LEAKAGE is $\leq$ 150 gallons per day through any one SG" and add a note that states "Not required to be performed until 12 hours after establishment of steady state operation," with surveillance frequency being 72 hours, which is addressed in Section 3.2.3.5.3 of this SE.

For the proposed changes to the TSs that are not addressed in other sections of this SE, the addition of "or primary-to-secondary LEAKAGE" to Condition A and SR 3.4.13.1 Note 2 are considered to be administrative changes because these changes support the more restrictive addition of primary-to-secondary leakage to Condition B and SR 3.4.13.2. The need for Note 2 with respect to SR 3.4.13.1 (i.e., not applicable to primary-to-secondary leakage) and for the proposed new SR 3.4.13.2, which deals with primary-to-secondary leakage, is discussed in the identified revision to the TS 3.4.13.2 Bases. The revised TS BASES state that SR 3.4.13.1 is not applicable to primary-to-secondary leakage because leakage rates of 150 gpd or less cannot be accurately measured by an RCS water inventory balance. Based on this, the NRC staff has reviewed these changes and concludes that they meet 10 CFR 50.36. Based on this, the NRC staff further concludes that these proposed TS changes are acceptable.

3.2.3.5.1 Deletion of Current LCO 3.4.13.d

Existing LCO 3.4.13.d currently specifies that the total primary-to-secondary leakage through all SGs shall be limited to 600 gpd and LCO 3.4.13.e specifies that the primary-to-secondary leakage through any one SG shall be limited to 150 gpd. The licensee states that the 600 gpd limit for leakage through all SGs is redundant to the 150 gpd limit through any one SG (i.e., Callaway has four SGs, so 4 x 150 = 600 gpd total leakage through all SGs) and, thus, the licensee is proposing deletion of the 600 gpd limit as being redundant to the 150 gpd/SG limit. Accordingly, the proposed amendment would delete LCO 3.4.13.d, but would retain the 150 gpd limit for any one SG in LCO 3.4.13. This revised requirement would allow total leakage through all SGs still to be limited to 600 gpd because all the individual SGs would be separately limited to 150 gpd. Because the existing LCO 3.4.13.d is redundant to LCO 3.4.13.e, the NRC staff concludes that the proposed deletion of LCO 3.4.13.d, the movement of the word "and" from the end of LCO 3.4.13.d (which is being deleted) to the previous LCO 3.4.13.c (which is not being deleted), and the re-numbering of existing LCO 3.4.13.e to LCO 3.4.13.d, is

acceptable.

3.2.3.5.2 TS 3.4.13, Condition B, Primary-to-Secondary Leakage

The primary-to-secondary leakage limit provides assurance against SG tube rupture at normal operating and faulted conditions. This, together with the allowable accident induced leakage limit, helps to ensure that the radiological dose contribution from SG tube leakage will be limited to less than the 10 CFR 100 and GDC 19 dose guidelines, or other NRC-approved licensing basis for postulated faulted events. The licensee proposed to add an additional "or" statement to Condition B with regards to primary-to-secondary leakage. As proposed, LCO 3.4.13 Condition B would state the following:

> Required Action and associated Completion Time of Condition A not met.
>
> OR
>
> Pressure boundary LEAKAGE exists.
>
> OR
>
> Primary-to-secondary LEAKAGE not within limit.

The proposed change is to add the last phrase "OR Primary-to-secondary LEAKAGE not within limit" given above.
The current requirements, LCO 3.4.13 Condition A, have a completion time of 4 hours to reduce leakage (other than pressure boundary leakage) to within limits after which LCO 3.4.13 Condition B (plant shutdown) must be entered. The proposed TS limit is more restrictive than the current requirements in that if primary-to-secondary leakage exceeds 150 gpd, then a plant shutdown must be commenced without an allowance to reduce leakage, as provided in Condition A. The revised Condition B would require the reactor to be in Mode 3 in 6 hours and Mode 5 in 36 hours if primary-to-secondary leakage is not within limits. As discussed in Section 3.2.3.5 of this SE, the licensee has excluded primary-to-secondary leakage from Condition A. The NRC staff has reviewed the proposed change to Condition B. These changes are additional restrictions on plant operations that enhance safety; therefore, the NRC staff has concluded that the addition of the phrase "OR Primary-to-secondary LEAKAGE not within limit" to Condition B is acceptable.

3.2.3.5.3 SRs 3.4.13.1 and 3.4.13.2

SR 3.4.13.1 currently requires the performance of an RCS water inventory balance. The amendment would revise SR 3.4.13.1 to require verification that RCS operational leakage is within limits by performance of an RCS water inventory balance. The accompanying TS Bases for this SR states that (1) primary-to-secondary leakage is also measured by performance of an RCS water inventory balance in conjunction with secondary side sampling and monitoring and (2) the RCS water inventory balance must be met with the reactor at steady-state operating conditions. As previously discussed in Section 3.2.3.5 of this SE, the licensee has proposed adding a note to this SR stating that this SR 3.4.13.1 is not applicable to primary-to-secondary leakage. The licensee would revise the accompanying TS Bases justifying this change, namely, that primary-to-secondary leakage of 150 gpd cannot be measured accurately by an

RCS water inventory balance. Therefore, the revised SR 3.4.13.1 would be restricted to only verifying the RCS operational leakage is within limits (i.e., LCO 3.4.13.a, .b, and .c) using an RCS water inventory balance. As discussed below, the licensee has proposed to revise SR 3.4.13.2 to verify that the primary-to-secondary leakage does not exceed the new LCO 3.4.13.d limit, the 150 gpd through any one SG, for which the RCS water inventory balance is not applicable. Therefore, revised SR 3.4.13.1 involves verification of RCS operational leakage and revised SR 3.4.13.2 requires verification of RCS primary-to-secondary leakage.

The new SR 3.4.13.2, with respect to primary-to-secondary leakage, replaces the current SR 3.4.13.2 which involved verifying SG tube integrity in accordance with the SGTSP (i.e., TS 5.5.9). As discussed earlier in this SE, the current TS 5.5.9 would be replaced by a new revised TS 5.5.9. The current SR 3.4.13.2 to verify tube integrity would be addressed by the proposed SRs in the new TS 3.4.17. TS 5.5.9 and TS 3.4.17 are addressed in Sections 3.2.3.3 and 3.2.3.1, respectively, in this SE.

The revised SR 3.4.13.2 would not specify the specific method to be employed; however, it would require that the Steam Generator Program include provisions for monitoring primary-to-secondary leakage. There are a variety of methods that can be used, and the NRC staff concludes there is no need to tie this surveillance to a specific method in order to ensure that the plant is operated safely and within its LCO limits. The licensee would state in the accompanying TS Bases that the primary-to-secondary leakage measurement uses continuous process radiation monitors or radio chemical grab sampling. The NRC staff notes that the EPRI PWR Primary-to-Secondary Leak Guidelines provide extensive guidance to this effect.

The accompanying TS Bases would also state that primary-to-secondary leakage is measured against the 150 gpd limit under room temperature conditions as described in the EPRI PWR Primary-to-Secondary Leak Guidelines. The Callaway safety analysis for steam line break assumes 1 gpm (i.e., 1440 gpd) primary-to-secondary leakage in the faulted loop as an initial condition. The NRC staff concludes that measurement of operational primary-to-secondary leakage under room temperature conditions relative to the 150 gpd operational limit is acceptable since it ensures that leakage under hot operational conditions will be less than assumed in the Callaway safety analysis and, thus, is in accordance with 10 CFR 50.36.

Based on the above, the NRC staff concludes that the proposed revisions to SR 3.4.13.1 and SR 3.4.13.2 are acceptable.

3.2.3.5.4 Definition of Leakage

The license proposed to revise the TS definition of leakage in TS Section 1.0. The licensee stated that these changes are editorial changes to (1) remove the phrase "SG leakage" from the TSs because that term is not used in the TSs and is not defined in the TSs, and (2) add the term "primary to secondary leakage" that is used in the TSs and TS Bases. Therefore, the licensee stated that it has proposed changes to the definition of leakage to use the term "primary to secondary leakage" instead of the term "SG leakage", which reflects TSTF-449, Revision 4.

Although the term "primary to secondary leakage" is also not defined in the TSs, this term is used in the TSs and TS Bases. Based on its review, the NRC staff concludes that the replacement of "SG leakage" by "primary to secondary leakage" improves the TSs and TS

Bases and, therefore, the change meets 10 CFR 50.36. Based on this, the NRC staff further concludes that the proposed changes to the definition of leakage are acceptable.

3.2.3.6 Conclusions

The licensee's proposed TS changes described in Section 3.2.1 of this SE establish a programmatic, largely performance-based regulatory framework for ensuring SG tube integrity is maintained. Based on this, the NRC staff concludes that the proposed changes address key shortcomings of the current TSs by ensuring that the Steam Generator Program for Callaway in the revised TSs is focused on accomplishing the overall objective of maintaining SG tube integrity. The program incorporates performance criteria for evaluating tube integrity that the NRC staff finds are consistent with the structural margins and the degree of leak tightness assumed in the current plant licensing basis. The NRC staff finds that maintaining these performance criteria provides reasonable assurance that the replacement SGs can be operated safely without an increase in risk.

The revised TSs would contain limited details concerning how the Steam Generator Program is to achieve the required objective of maintaining SG tube integrity, the intent being that the licensee will have the flexibility to determine the specific strategy for meeting this objective. However, the NRC staff finds that the revised TSs include sufficient regulatory constraints on the establishment and implementation of the Steam Generator Program to provide reasonable assurance that tube integrity will be maintained. Failure to meet the performance criteria will be reportable pursuant to 10 CFR 50.72 and 50.73. The NRC ROP provides a process by which the NRC staff can verify that the licensee has identified any SGTSP deficiencies at Callaway that may have contributed to such an occurrence and that appropriate corrective actions have been implemented.

In conclusion, the NRC staff finds that the proposed TS changes involving SG tube integrity in Section 3.2.1 of this SE conform to the requirements of 10 CFR 50.36 and establish requirements in the TSs that will provide reasonable assurance that tube integrity is maintained without undue risk to public health and safety. Based on this, the NRC staff concludes that the proposed TS changes are acceptable.

3.3 Plant Systems Review

3.3.1 Introduction

By the application dated September 17, 2004, as supplemented by a letter dated February 11, 2004, the licensee requested changes to TS 3.7.1, "Main Steam Safety Valves" and provided an evaluation of the assumptions used in the supporting analysis developed for the replacement SGs. In the proposed changes to TS 3.7.1, the maximum allowable power for 3 operable MSSVs per steam generator would be decreased from less than 49 percent of RTP to less than 45 percent of RTP. The analysis provided by the licensee to support the TS change assumes a reactor coolant average temperature (Tavg) range of 570.7°F to 588.4°F. This TS change is addressed in Section 3.3.3.2 of this SE.

3.3.2 Regulatory Evaluation

The acceptability for the proposed changes to TS 3.7.1 is based on the following requirements

of GDC 34:

1. As related to the system function of transferring residual and sensible heat from the reactor system in indirect cycle plants.

2. As related to the ability to use the system for shutting down the plant during normal operations. The operation of the steam dump system eliminates the need to rely solely on the safety systems which are required to meet the redundancy and power source requirements of this criterion.

3.3.3 Technical Evaluation

The licensee currently has Westinghouse Model F SGs installed at the Callaway Plant and it intends to replace them with Framatome-designed Model 73/19T SGs, the replacement SGs. In support of this replacement and the associated license amendment, Westinghouse has performed analytical work to address the NSSS areas that are affected by installation of the replacement SGs and the results of the analysis are documented in WCAP-16265-P, which was submitted in the licensee's application.

3.3.3.1 Acceptability of Assumptions in WCAP-16265-P

One of the assumptions used in the development of WCAP-16265-P states that the full power normal operating T avg ranges from 570.7 °F to 588 °F. The licensee's evaluation identified that the installed steam dump valves do not have adequate capacity to operate at the new plant conditions after the installation of the replacement SGs when full-load Tavg is lower than 573 °F.

By letter dated December 20, 2004, the NRC staff requested the licensee to justify operation below 573 °F. In supplemental information provided by letter dated February 11, 2005, the licensee stated that the steam dump valves are not safety significant and that they are not credited in the safety analyses. The licensee also stated that, in order to operate at a nominal Tavg lower than 573 °F, it would have to prepare a modification package that would modify the design of the steam dump system and appropriate Callaway Final Safety Analysis Report (FSAR) page changes would be involved with the design change. The design change will be perform under 10 CFR 50.59, without prior NRC review and approval, because the low end of the Tavg range is not a limit in the TSs and the steam dump valves are not safety related. TS 3.4.2, which is unchanged by the proposed amendment, provides the only lower limit for Tavg in the TSs. The no-load Tavg must be higher than 551°F prior to taking the reactor critical.

As stated above, the licensee recognized that the current installed steam dump valve design constrains the low end of the full-power Tavg range to 573°F. The licensee stated that it will operate within acceptable Tavg range to ensure adequate steam dump capacity and the steam dump would be modified under 10 CFR 50.59 prior to plant operation below a full-power Tavg of 573 °F. Based on this, the NRC staff concludes that the (1) assumptions for the analysis and (2) controls to prevent operation below Tavg of 573°F are acceptable.

3.3.3.2 TS 3.7.1 on MSSVs

TS Table 3.7.1-1 in LCO 3.7.1 specifies the maximum allowable power level for the number of inoperable MSSVs per SG. The MSSV provide the overpressure protection for the SGs in that the valves will open to relieve pressure if the pressure is above the SG design pressure. The design basis of the MSSVs is to limit the secondary side pressure to less than or equal to 110 percent of design pressure for any DBA or abnormal occurrence.

There are five MSSVs on each of the four replacement SGs. If one MSSV on one or more SGs is inoperable, the plant is not allowed to operate at 100 percent RTP, or 100 percent of the plant licensed power level. The licensee proposes to revise TS Table 3.7.1-1 to decrease the maximum allowable power for three operable MSSVs per SG from less than 49 percent RTP to less than 45 percent RTP to reflect the replacement SGs and associated safety analyses.

The licensee's contractor (Westinghouse) performed an updated Loss of Load/Turbine Trip (LOL/TT) analysis covering operation with inoperable MSSVs, which is presented in WCAP-16265-P. A similar analysis had been performed for the Callaway Plant in 1999. The results of the analysis showed that the current TS values remain valid, with the exception of the case with only three operable MSSVs per SG. In this scenario, part-power operation with the high neutron flux setpoint set at 45 percent RTP was found to be acceptable, instead of the previous value of 49 percent RTP.

As discussed above, the results of the LOL/TT analysis shows that the licensee’s proposed change to TS 3.7.1, which decreases the maximum allowable power for three operable MSSVs per SG from less than 49 percent RTP to less than 45 percent RTP, will maintain the secondary side pressure less than or equal to 110 percent of design pressure for any DBA or abnormal occurrence. Based on this, the NRC staff concludes that the licensee’s proposed changes to TS 3.7.1 meets the requirements of GDC 34, in that the remaining operable MSSVs provide adequate residual heat removal capability for the specified initial power level, and, therefore, are acceptable.

3.3.3.3 Conclusions

Based on the above evaluation, the NRC staff concludes that (1) the assumptions for the analysis and controls to prevent operation below Tavg of 573°F and (2) the proposed change to TS Table 3.7.1-1 are acceptable.

3.4 Reactor Systems Review

3.4.1 Introduction

By the application dated September 17, 2004, and the supplemental letters dated May 26, June 17 (two letters), and July 29, 2005, the licensee submitted information and proposed changes to the TSs to support the license amendment request (LAR) supporting the replacement of the existing Westinghouse Model F SGs with the new Framatome 73/19T SGs. The licensee also proposes to eliminate the TTD function from the 7300 Process Protection Cabinets (also discussed in Section 3.1 of this SE). The licensee has incorporated design features into the replacement SGs that would reduce water level instabilities and unnecessary plant trips at low power levels, demanded by the low SG water level protection system logic.

Since the Framatome SG 73/19T is larger than the original Westinghouse SGs (i.e., its tubes have a larger tube diameter, there are more tubes, and there is a greater tube surface area), it is expected that the proposed replacement SGs will improve plant operations.

In Section of 1.5.1 of WCAP-16265-P, the licensee identified that the evaluations or analyses for the replacement SGs were performed using analytical techniques previously approved for Callaway except for the following: (1) RETRAN-02 for the SGTR and MSLB mass and energy release and (2) VIPRE-01 for core thermal hydraulic design. These two computer codes are addressed in WCAP-14882-P and WCAP-14565-P, respectively, that were reviewed and approved by NRC in letters dated February 11, 1999, and January 19, 2004, respectively. The NRC staff agrees that these computer codes are applicable to Callaway.

Section 3.4.3.11 of this SE addresses the following TS changes:

- TS 2.1.1.1, Safety Limits (SLs)
- TS Table 3.3.1-1, RPS Instrumentation
- TS 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits (DNB Parameters)
- TS Table 3.7.1-1, MSSVs
- TS SRs 3.4.5.2, 3.4.6.2, 3.4.7.2, and LCO 3.4.7 on RCS Loops for Modes 3, 4, and 5

3.4.2 Regulatory Evaluation

The NRC staff reviewed the licensee's evaluations and analyses supporting the replacement SGs. The staff performed its review in accordance with the criteria and requirements currently applicable to the Callaway Plant in the following areas: nuclear and fuel design; thermal-hydraulic design; systems evaluations; and LOCA and Non-LOCA transients and accident analyses. Each of the review areas addressing the LOCA and non-LOCA transient and accident analyses is evaluated separately in subsections below within Section 3.4.3 of this SE. Each of these subsections describes the applicable regulatory requirements and acceptance criteria, the licensee's analyses or evaluations, and the NRC staff's conclusions.

A detailed discussion about the computer codes and methodologies used in the review of the replacement SGs is in Section 3.4.3.8.2 of this SE. The staff also used the NRC Standard Review Plan (SRP), NUREG-0800 (Reference 4.1), in performing its review.

3.4.3 Technical Evaluation

The LAR sections given in the titles of the subsection to Section 3.4.3 of this SE refers to the appropriate section in WCAP-16265-P, except for Section 3.4.3.3.1 of this SE on the TTD function where the reference is to Attachment 1 of the application.

3.4.3.1 NSSS Parameters (LAR Section 2.2)

The NSSS design parameters provide the RCS and secondary system conditions for use in NSSS analyses and evaluations. The licensee provided a list of key plant parameters for the proposed replacement SGs in Table 2.1 of its application. The major parameters include reactor power level, NSSS power level, thermal design flow, reactor coolant pressure and temperatures, SG pressure, steam temperature, and steam flow rate. The licensee used a

range of conditions for the Tavg, the SG tube plugging level, and a range of feedwater temperature to generate the design operating parameters. Full-power normal operating vessel Tavg ranged from 570.7 EF to 588.4 EF, the SG tube plugging level can vary from 0 percent to 5.0 percent, and feedwater temperatures ranged between 390 EF and 446 EF. The current NSSS power level of 3579 MWt, current fuel type 17x17 V5, and current thermal design flow of 93,600 gpm/loop remain unchanged. The analysis of the steam dump valve capacity resulted in a restriction on the proposed Tavg range. The installed steam dump valve capacity is adequate at the replacement SG operating conditions, provided that the full-load Tavg is no lower than 573 EF. These parameters were used in the licensee's safety analyses performed to support its proposed installation of the replacement SGs. Because the results of the licensee's analyses were used to determined if there are acceptable margins to safety analysis limits, the NRC staff reviewed these NSSS design parameters to see if they adequately represent the plant operating conditions at the proposed replacement SG conditions. Based on its review of these parameters, the NRC staff concluded that they were acceptable as the input data for the licensee's analyses.

3.4.3.2 NSSS Design Transients (LAR Section 3.1)

The NSSS design transients are traditionally developed for fatigue analyses of the various NSSS components using conservative assumptions. The licensee evaluated the current NSSS design transients that were based on conservative NSSS design parameters to determine any impact of replacement SG conditions. The NSSS design transients are based on the thermal design flow that remains identical to the current value. Also, the licensee compared the design parameters used in the existing design transients and for the replacement SG parameters and concluded that the existing design transients remain bounding and applicable to the replacement SGs. The transient curves for the replacement SG conditions were provided to all system and component designers for use in their specific analyses and evaluations for the replacement SGs. Even though the existing design transients bound the replacement SG parameters, all of the design transients were re-analyzed or evaluated based on the replacement SG design parameters to show the regulatory requirements are still met. Since there were no changes required for the NSSS design transients, the NRC staff concluded that the existing licensing basis analyses remain bounding and are, therefore, acceptable for replacement SGs.

3.4.3.3 NSSS Systems (LAR Section 4.1)

The RCS and secondary system conditions, that are assumed in accident analyses and safety evaluations, are based upon the NSSS design parameters. The key design parameters include reactor power level, NSSS power level, thermal design flow, reactor coolant pressure and temperatures, SG pressure, steam temperature and steam flow rate. In this LAR, most of the changes in NSSS design parameters pertain to the SGs. They include an increased tube heat transfer area, a higher tube bundle height, a higher steam pressure, and a longer narrow range level instrument span.

A comparison of the replacement SGs to the original SGs is provided in Table 2 on the following page.

There is a 60 percent reduction in maximum carryover, a 5 percent increase in steam pressure, a 17 percent increase in Narrow Range Span, and a 44 percent increase in heat transfer

surface area. Although these changes would benefit normal plant operations, this safety evaluation will focus upon their effects on plant safety. The longer narrow range span, for instance, would lead to a more stable indication of water level, and fewer low-low SG water level reactor trips during startup operations. This is one of the justifications behind the licensee's proposal to eliminate the TTD function from the 7300 Process Protection Cabinets.

There are other safety-related implications associated with the proposed changes in NSSS design parameters. The increase in heat transfer surface area would affect secondary-side induced transients, such as load rejection, loss of feedwater, and steam line rupture. A change in secondary system cooling rate, for example, would be more readily seen by the RCS due to the improved primary-to-secondary heat transfer. SG geometry also has an effect. For example, the increased tube bundle height means that the SG tubes would be exposed sooner during events wherein shell side water inventory is boiled off, such as the loss of feedwater accident.

These, and other considerations are addressed in the accident analyses and evaluations in the licensee's letters related to the LAR. The licensee performed plant transients analyses and evaluations to verify that sufficient core cooling capability exists under replacement SG design conditions. Furthermore, the NSSS systems functional requirements and performance criteria were reviewed relative to the NSSS design parameters to show that each system remains capable of performing its design-basis functions for the revised RCS operating conditions. NSSS fluid systems analyses and evaluations were performed to consider the proposed NSSS design parameter changes associated with the replacement SGs. The NSSS design parameter changes are acceptable, since they were verified by accident analyses and evaluations, performed with NRC-accepted methodologies. The licensee also verified the adequacy of the

TABLE 2

COMPARISON OF REPLACEMENT SGs TO ORIGINAL SGs

	replacement SG	original SG	Change (percent)
Tube Material	Alloy 690TT	Alloy 600MA	
Tube Pitch Geometry	triangular	square	
Tube Pitch Geometry	triangular	square	
Tube Support Plate Type	broached	broached	
Tube OD (in)	0.75	0.6875	9.09
Tube Wall Thickness (in)	0.043	0.04	7.50
Tube Pitch (in)	1.031	0.98	5.20
Number of Tubes	5872.0	5626.0	4.37
Tube Surface Area (sq ft)	78946.0	55000.0	43.54
Bundle Height (in)	433.9	348.0	24.68
Tube Flow Area (sq ft)	14.12	11.32	24.69
Weight, Dry (lbs)	743100.0	715000.0	3.93
Circulation Ratio	4.00	3.64	9.89
Best Estimate RCS Flow (gpm)	104438.0	101900.0	2.49
Steam Press (psia)	1021.0	970.0	5.26
Specified Maximum Carryover (percent)	0.10	0.25	-60.00
Narrow Range Span (in)	150.0	128.0	17.19
Wide Range Span (in)	574.0	559.0	2.68

safety injection system (SIS) during the injection and sump recirculation phases following a LOCA in the LOCA analysis performed for the replacement SG design conditions. For the non-LOCA events, the SIS performance was also verified by various safety analyses performed in support of the replacement SGs.

Based on the results of the safety analyses addressed in Section 3.4.3.8 below of this SE, the NRC staff finds that revised RCS operating conditions associated with the replacement SG are acceptable.

3.4.3.3.1 TTD Function (LAR Attachment 1, Section 3.2)

The TTD concept was developed to reduce reactor trips due to SG low water levels when operating at low power. Because the SG water level has been difficult to maintain at low power levels, TTD allows the control room operators additional time to correct SG level before a reactor trip is initiated. For Callaway, the additional time, depending on power level, was no more than 4 minutes. These additional minutes would afford the operators an opportunity to correct SG level and avoid a reactor trip. Design features have been implemented into the replacement SGs that reduce water level instabilities and inadvertent plant trips at low power levels with low SG water level. The replacement SGs will also have a larger level span and lower environmental allowance monitor setpoints than the original SGs. Both of these design features will help compensate for the elimination of the TTD circuitry by providing the operators with additional time to recover the SG level and avoid a reactor trip. Based on this, the NRC staff concludes the TTD function from the 7300 Process Protection Cabinets is no longer needed with the replacement SGs and it is, therefore, acceptable to eliminate the function.

3.4.3.4 Overpressure Protection (LAR Section 4.3.2)

The licensee provided the results of RCS overpressure protection analyses to demonstrate that the Callaway safety valve design capacity continues to be sufficient to limit the pressure to less than 110 percent of the RCPB design pressure (as specified by Section III, Article NM-7000 of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (i.e., the ASME Code) (Reference 4.2)) during the most severe abnormal operational transient and the reactor scrammed with sufficient available margin to account for uncertainties in design and operation of the plant.

The licensee performed the analyses incorporating assumptions consistent with those specified in NUREG-0800, SRP 5.2.2, Section II.A, including the assumption that reactor scram is initiated by the second safety-grade signal from the reactor protection system (RPS). The licensee used an upgraded computer model (i.e., RETRAN-02) from what had been used in the previous evaluations for these valves. As explained in Section 3.4.1 of this SE, this code model is an acceptable model for these analyses for Callaway. With the conservative assumption that the second trip (overtemperature Delta-T (OTΔT)) acts before the first trip (high pressurizer pressure), the results were well below the 110 percent criterion, leaving sufficient available margin to account for uncertainties in design and operation of the plant. The staff finds that the analyses are acceptable because they were performed using an acceptable analysis model and analysis assumptions consistent with the guidance provided in SRP 5.2.2, Section II.A. Based on the analyses results, the staff also finds that these analyses

demonstrate that the Callaway safety valves continue to have sufficient capacity to satisfy their

safety requirements, as stated above.

The pressurizer power operated relief valves (PORVs) were sized and evaluated for Callaway operation at 100 percent RTP. Therefore, the proposed replacement SG replacement, which does not increase the RTP, will not change the existing evaluation of the PORVs, or its acceptability. The staff finds this acceptable.

The licensee also evaluated the replacement SGs for the impact on the performance of the atmospheric dump valves. The licensee's analyses demonstrated that for a 50 percent load rejection event activation of the atmospheric dump valves would prevent actuation of the associated steam line safety valves, the pressurizer PORVs, the pressurizer safety valves (PSVs), and a reactor trip.

Based on this, the NRC staff finds that the overpressure protection provisions for Callaway at the power associated with the proposed installation of the replacement SGs remain acceptable in that they address their functional requirements.

3.4.3.5 Low-Temperature Overpressure System (LTOP) (LAR Section 4.3.5)

The low-temperature overpressure protection (LTOP) system is the cold overpressure mitigation system (COMS) at Callaway. This system provides RCS pressure relief capability at relatively low-temperature operation (i.e., at RCS temperature less than 350 EF). Two PORVs are used to provide the automatic relief capability during the design-basis mass input (MI) and the design-basis heat injection (HI) transients to automatically prevent the RCS pressure from exceeding the pressure and temperature limits of 10 CFR 50, Appendix G.

There are differences between the original Westinghouse Model F SGs and the replacement Framatome Model 73/19T SGs that would affect the current design-basis LTOP HI transient. The licensee performed an evaluation of the MI transient and concluded that the current MI analysis remained applicable for the replacement SG. The licensee re-analyzed the HI transient with the replacement SGs. Using the HI transient re-analysis results and the current MI results, the licensee developed LTOP setpoints.

The current pressure and temperature limits report (PTLR) for Callaway has RCP operation restrictions. Two RCPs would be allowed to operate whenever the RCS temperature is $\leq$ 200 degree ^{o}F. The licensee has decided to implement COMS setpoints that have no RCP operation restrictions. These COMS setpoints are more limiting than the currently presented setpoints in the PTLR with the RCP operation restriction. The licensee evaluated the COMS setpoints for no RCP operation restrictions and determined that these setpoints will not present any undue burden on plant operation. Therefore, upon approval of this amendment, the licensee will revise the PTLR for Callaway and change the COMS setpoints to reflect no RCP operation restrictions as part of its implementation of the installation of the replacement SGs. The current LTOP arming temperature of 275 ^{o}F remains applicable for the replacement SG program. Based on this, the NRC staff finds that the COMS analysis and setpoints are acceptable for the replacement SGs.

3.4.3.6 Fuel Assemblies (LAR Section 5.3)

The fuel that is currently in the Callaway core is the Westinghouse 17×17 VANTAGE+ fuel, which is not being changed because of the replacement SGs. The non-LOCA transient analyses account for the fuel design features by way of the fuel-related input assumptions such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow.

Because the fuel design is not being changed and based on the results of the safety analyses addressed in Section 3.8 of this SE, the NRC staff concludes that the fuel design remains acceptable for the replacement SGs.

3.4.3.7 Control Rod Drive Mechanisms (CRDM) (LAR Section 5.4)

The plant is equipped with full length Model L-106A1 CRDMs and capped latch housings (CLHs). The licensee evaluated these CRDMs and CLHs to account for the replacement SGs and the associated NSSS design transients. This evaluation focuses upon the pressure boundary components of the existing CRDMs and CLHs, given the installation of the replacement SGs.

The input parameters that were used by the licensee to perform the analyses and evaluations for the replacement SGs include the original NSSS design parameters and NSSS design transients, the replacement SG parameters and NSSS design transients, and the current design-basis evaluations for the CRDMs and CLHs. The seismic analyses and non-pressure boundary component evaluations for the CRDMs and CLHs are unaffected.

The CRDMs and CLHs are installed in the reactor vessel upper head (hot head CRDMs) and are affected by the RCS pressure, vessel outlet temperature, and the hot leg NSSS design transients. The RCS pressure is the same for both the replacement SG and for the plant current licensing basis. Therefore, based on this, the NRC staff concludes that the existing analyses for the CRDMs and CLHs remain acceptable to assess whether the ASME Code pressure requirements are satisfied for the replacement SGs.

The highest vessel outlet temperature for the replacement SGs is 620 ^{o}F. Since most of the previous analyses used material allowable values based on the design temperature of 650 ^{o}F, the revised temperatures defined for the replacement SGs are, in most cases, enveloped by the current analyses. The only exceptions are the Loss of Flow Transient evaluations, which are addressed for the new transients by multiplying the existing stresses by the ratio of the new transients to old transients. Although this approach produces a smaller margin of safety than would a specific analysis, it indicates that all cases remain within the allowable values.

Based on the review discussed above, the staff NRC concludes that the CRDM and CLH pressure boundary components are acceptable in accordance with the ASME Code (Reference 4.2) for the replacement SGs.

3.4.3.8 Transient and Accident Analyses (LAR Section 6.1)

The licensee re-analyzed the FSAR Chapter 15 LOCA and non-LOCA transients and accidents in support of the replacement SGs. These analyses were performed by the licensee at a RTP of 3565 MWt using plant parameter values for the operating conditions. The initial condition uncertainties for RCS Tavg control and SG water level control were affected by the replacement SG conditions. The initial condition uncertainties were recalculated for the replacement SG

design conditions for use in the Callaway analyses and/or evaluations that were performed by the licensee to assess the acceptability of the transient and accident safety analyses for the replacement SG. Table 6.1-1 of WCAP-16265 lists the initial condition uncertainties. These uncertainty calculations were performed for the replacement SG operating conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures.

The NRC staff reviewed the licensee's transient and accident analyses for the replacement SG conditions to verify that the acceptance criteria were still met under these conditions. The NRC staff's review of the LOCA and non-LOCA transients and accidents is discussed in the following sections of this SE.

3.4.3.8.1 LOCA Evaluation (LAR Section 6.2)

In its application, the licensee described the Callaway large break LOCA (LBLOCA) and small-break LOCA (SBLOCA) analyses performed at the licensed power, assuming the replacement SGs and the 17x17 Westinghouse V+ fuel (with ZIRLO cladding) assemblies. The LBLOCA analyses were performed with the Westinghouse LBLOCA methodology with BASH model (Reference 4.3). The SBLOCA analyses' results were recalculated using the Westinghouse NOTRUMP (COSI) SBLOCA methodology (Reference 4.4).

The NRC staff reviewed the LBLOCA and SBLOCA analyses to assure that the licensee met the requirements of 10 CFR 50.46 and found that the practice of analyzing only integer break sizes may not provide reasonable assurance that the most limiting break size will be identified as required by 10 CFR 50.46a(1)(i). Analysis of only integer diameter break sizes produces too coarse of a break spectrum from a break area standpoint. Following discussion with the licensee, the licensee committed (See Section 4.0 of this SE on Regulatory Commitments) to perform additional analyses to identify the worst SBLOCA. Based on this, the NRC staff finds that it is acceptable for the licensee to provide a future analysis for Callaway that identifies the worst break from a peak clad temperature and peak local oxidation standpoint because the limiting calculated SBLOCA peak cladding temperature (PCT) for Callaway is reported by the licensee in WCAP-16265-P at 1043 °F and has more than sufficient margin (i.e., more than 1000 °F margin) with respect to the 2200 °F limit required by 10 CFR 50.46. Thus, the NRC staff concludes that the PCT for the worst SBLOCA for Callaway should remain less than the limit. However, because the change may be more than 50 °F for the worst small break PCT based on the integer diameter break spectrum analysis, the licensee would be required to report such a change to the NRC pursuant to the reporting requirements in 10 CFR 50.46.

The licensee provided the LOCA plant-specific analyses results for the Westinghouse fuel. Table 3 on the next page provides the licensee's LOCA analysis results. The calculated values given in the table are less than the limits specified in 10 CFR 50.46(b)(1)-(3) that requires the following: (1) the PCT to be less than 2200 °F, (2) the maximum cladding oxidation to be less than 17 percent, and (3) the maximum hydrogen generation to be less than 1.0 percent. As a result, the licensee has demonstrated compliance with 10 CFR 50.46(b)(1)-(3). Additionally, the licensee, as discussed below, has demonstrated compliance with 10 CFR 50.46(b)(5). In as much as no other consideration affects the Callaway core geometry, this assures that the

TABLE 3 - LOCA ANALYSIS RESULTS

Limiting break Type/Size/location	LBLOCA/ Pump Discharge Cd = 0.6	SBLOCA/ 4-Inch Pump Discharge
Fuel Type	Westinghouse V+ 17x17 ZIRLO fuel	Westinghouse V+ 17x17 ZIRLO fuel
Fuel PCT	2014 ^{O}F	1528 ^{O}F
Maximum Local Oxidation	3.53% *	0.46% *
Maximum Total Core-wide Hydrogen Generation (All Fuel)	(< 0.3%)*	(< 0.3%)*

* These LOCA local oxidation and core-wide hydrogen generation values [1] are bounding LOCA values for the fuel. The licensee states that operational controls are such that the total oxidation (including LOCA and pre-LOCA) will always be below 16 percent. The values for core-wide hydrogen generation do not include a pre-LOCA amount. This is reasonable because normal operational monitoring and procedures maintain operational (pre-LOCA) core-wide hydrogen at a very low level.

Callaway core will remain amenable to cooling during an accident as required by 10 CFR 50.46(b)(4).

In summary, the NRC staff concludes that the licensee's LOCA analyses were performed with acceptable LOCA methodologies that apply to Callaway and demonstrate that it complies with the requirements of 10 CFR 50.46(b)(1)-(5). Based on this, the NRC staff finds that the licensee's LOCA analyses presented for the replacement SGs are acceptable.

Overall Applicability of LOCA Analysis Methodologies:

The Westinghouse LBLOCA methodology (Reference 4.3) specifically applies to Callaway since it applies to all Westinghouse 2-, 3-, and 4-loop plant designs and the Callaway plant is a 4-loop Westinghouse design. The licensee also used the Westinghouse NOTRUMP (with COSI) SBLOCA methodology (Reference 4.4) to perform SBLOCA analyses for the replacement SGs. This methodology applies to all Westinghouse 2-, 3-, and 4-loop plant designs, and, therefore, it is applicable to the Callaway plant.

In a response to an NRC request for additional information (RAI), the licensee stated that both Callaway and its vendor (Westinghouse) have ongoing processes that assure that the values and ranges of the LOCA analyses parameter inputs conservatively bound the values and ranges of the as-operated plant for those parameters.

These LOCA methodologies apply to plants of Westinghouse design and Westinghouse fuels, and have no technical limitations that would preclude their use for the proposed installation of the replacement SGs. Further, the licensee's statement above, about the processes that assure that the values and ranges of the LOCA analyses' parameter inputs conservatively bound the values and ranges of the as-operated Calllaway, provides assurance that the analyses results obtained using those LOCA methodologies will continue to apply to Callaway. Based on this, the NRC staff concludes that Westinghouse LOCA methodologies identified above are acceptable for application at Callaway for this amendment.

Slot Breaks at the Top and Side of the Pipe

In an NRC RAI, the NRC staff requested that the licensee address slot breaks at the top and side of a reactor pump discharge cold leg pipe, which could, under some circumstances lead to greatly extended periods of core uncovery. This scenario can result in fuel cladding oxidation in excess of the 10 CFR 50.46(b)(2) limit, and also possibly exceed the total hydrogen limit of 10 CFR 50.46(b)(3). The licensee addressed this for the replacement SGs in WCAP-16265. In its response, the licensee stated that the Emergency Operating Procedures (EOPs) at Callaway were based on approved Westinghouse Owners Group (WOG) EOP guidelines and direct timely operator actions that would avoid the conditions for extended core uncovery. The licensee indicated that the operator procedures and actions would be effective in LOCA scenarios because extended core uncovery would take a significant amount of time to develop. The licensee concluded that the existing provisions continue to apply to the upcoming cycle of operation, because the extended core uncovery issue of concern is independent of the operating cycle and fuel, and thus not dependent of the replacement SGs.

Based on its review of the information provided by the licensee, and as set forth above, the

NRC staff concludes that the licensee's analysis has successfully addressed this issue for Callaway. The resolution of this issue applies to the current Callaway amendment; however, approval of this amendment does not resolve the ongoing NRC staff generic issues related to slot breaks at the top and side of the pipe for the NSSS, or vendor, methodologies.

Downcomer Boiling

The licensee provided the results of an analysis it had performed, and other information using the approved Westinghouse BASH LBLOCA methodology, from which the licensee concluded that following a LBLOCA Callaway would attain a stable and sustained core quench (Reference 4.5). This indicates that, for Callaway, downcomer boiling would not occur to the extent that it would significantly degrade core cooling in the time subsequent to the calculated core quench in a LBLOCA transient. Based on this, the NRC staff finds that this is acceptable for the replacement SGs.

The NRC staff is presently pursuing concerns related to downcomer boiling in a generic matter. If that review raises any concerns applicable to the LBLOCA analyses at Callaway, then the NRC staff will request the licensee to address these issues consistent with any generic communication to the industry resulting in a generic resolution.

Post-LOCA Long Term Cooling and Boron Precipitation

The licensee stated in its submittals that the replacement SGs do not introduce an increased loop resistance or pressure drop from the core exit to the discharge in the pump coolant discharge leg. Because of this, the analyses of the mixing volume and the resultant boric acid precipitation timing and switch to simultaneous injection will remain unchanged with the new SGs. Therefore, the NRC staff concludes that the current licensing basis for post-LOCA long-term cooling and boron precipitation is not being changed by the amendment. However, having concluded this and while post-LOCA long term cooling performance, including precipitation timing following all LOCAs will not change adversely as a result of the replacement SGs, the NRC staff also concludes that approval of this amendment does not constitute approval of the analysis methods and results to compute the boric acid precipitation timing and does not resolve the ongoing NRC staff generic issues pertinent to the methods and analyses employed by the vendors to assess post-LOCA long-term cooling and boric acid precipitation following large and small break LOCAs. If that review raises any concerns applicable to the LBLOCA analyses at Callaway, then the NRC staff will request the licensee to address these issues consistent with any generic communication to the industry with a generic resolution.

3.4.3.8.2 Non-LOCA Transients and Accidents (LAR Section 6.3)

The licensee re-analyzed the FSAR Chapter 15 non-LOCA events and accidents using the replacement SG design conditions and NRC-approved computer codes and methodologies. Tables 6.3.2, 6.3.3, and 6.3.4 in the licensee's application provide the non-LOCA re-analyses results, plant initial conditions and assumptions, and the computer codes used in the re-analyses, respectively, for the replacement SGs.

For most events, the licensee used the RETRAN-02 computer code to simulate the transient response characteristics for Callaway, as described and presented in WCAP-14882-P-A

(Reference 4.6), the VIPRE-01 code (Reference 4.7) for reactor core subchannel thermal-hydraulic calculations, and the ANC code (Reference 4.8) for neutronic calculations. The licensee stated that, in all their applications, the codes were used within their specified conditions and restrictions.

The licensee also stated that it used the approved revised thermal design procedure (RTDP) methodology, as discussed in WCAP-11397-P-A (Reference 4.9), in performing certain non-LOCA safety analyses that result in a reduction of thermal margin. Upon review of the licensee's application, the NRC staff concludes that the licensee's application of RTDP methodology in these analyses is acceptable because, as stated by the licensee in WCAP-16265-P, the above computer codes that were used satisfy the conditions and restrictions set on the RTDP methodology for application at Callaway.

In the discussion below, there are references to the American Nuclear Society (ANS) accident conditions. ANS 51.1, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants - 1983; replaces ANSI N18.2 - 1973. *Inter alia*, ANS 51.1 categorizes accidents and transients into four classes (or Conditions), according to estimated frequency of occurrence. Condition I events are operational transients. These events occur relatively frequently, and do not require any protective actions. Condition II events, also known as (aka) anticipated transients or events of moderate frequency, may occur during a calendar year of plant operation, and may require a reactor trip and possibly some corrective actions. The plant should be capable of returning to power shortly after a Condition II event. Condition III events, aka infrequent events, may result in limited fuel damage and small offsite releases. Condition IV events, aka design-basis events or limiting faults, may result in significant fuel damage and offsite releases.

ANS 51.1 also defines acceptance criteria for each class of events. The acceptance criteria allow for more fuel damage and offsite releases for the more infrequent events. For example, the acceptance criterion for Condition II events does not allow any fuel damage, and the acceptance criterion for Condition IV events allows for extensive fuel damage, as long as the core remains in a coolable geometry. If the risk of an event is defined as the product of its frequency of occurrence and its consequences, then the four ANS 51.1 categories represent approximately equal levels of risk.

3.4.3.8.2.1 Excessive Heat Removal Due to MFW Malfunctions (LAR Section 6.3.1)

A change in SG feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the RCS. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve or feedwater bypass valve, failure in the feedwater control system, or operator error. Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to an increase in power level. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. RPS and safety systems are actuated to mitigate the transient. The acceptance criteria are based on critical heat flux not being exceeded, pressure in the RCS and main steam system (MSS) being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Specific review criteria are contained in SRP Section 15.1.1-4.

The licensee stated that it used the RETRAN-02 (Reference 4.6) computer code to analyze the RCS and core response to the excessive heat removal due to a feedwater system malfunction. RETRAN-02 also approximates the transient value of departure from nucleate boiling ratio (DNBR) based on input from the Callaway core thermal safety limits. The core thermal safety limits define the limits of operation, in terms of power, temperature, and pressure (at a constant flow), that produce a DNBR limit value that guarantees, to a confidence level of 95 percent, that 95 percent of the fuel (i.e., thimble and typical cells) would not experience departure from nucleate boiling (DNB). The RPS provides the required reactor trip for this event. The results show that RCS pressure remains below 110 percent of design value. The limiting case DNBR value, provided by the licensee in Table 6.3.2 of its application, is 1.733, which is well above the safety limit of 1.55.

Based on its review of the licensee's analysis, the NRC staff concludes that the licensee's analysis was performed using acceptable analytical models. Because the limiting case DNBR value is above the safety limit and the pressure in the RCS and MSS will be maintained below 110 percent of the design pressure, the NRC staff further concludes that the licensee has demonstrated that the RPS and safety systems will continue to ensure the critical heat flux will not be exceeded. Based on this, the NRC staff also concludes that Callaway will continue to meet the regulatory requirements following the installation of the replacement SGs and, therefore, with respect to the excessive heat removal due to feedwater system malfunction event, the proposed replacement SGs are acceptable.

3.4.3.8.2.2 Excessive Increase In Secondary Steam Flow (LAR Section 6.3.2)

An excessive increase in secondary steam flow, an excessive load increase incident, is an American Nuclear Society (ANS) Condition II (Reference 4.14) event that is characterized by a rapid increase in the steam flow to a level beyond that which is needed to match the reactor core power generation. As a result, the core is cooled, and reactivity and power increase to match the higher steam flow. A plant should be capable of tolerating a 10 percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 95 percent of full power without tripping. This event could be caused by an operator error, or an equipment malfunction in the steam dump control or turbine speed control. The acceptance criteria are based on critical heat flux not being exceeded (i.e., the minimum DNBR not going below the DNBR limit), pressure in the RCS and MSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a rate that would cause fuel centerline melt.

The licensee stated that it evaluated this event by verifying that the plant operating conditions for the replacement SGs, following the steam flow increase, remain within the acceptable operating region, as defined by the core thermal limits of Figure 6.3.1 of its application. In doing so, the licensee is stating that the minimum DNBR for the replacement SGs remains above the DNBR safety limit value of 1.55.

Based on its review of the licensee's evaluation of the excessive load increase incident, the NRC staff concludes that the licensee's evaluation demonstrates that the DNBR safety analysis limit is satisfied for this event for the replacement SGs. Based on this, the NRC staff also concludes that Callaway will continue to meet the regulatory requirements following the installation of the replacement SGs and, therefore, with respect to the excessive load increase incident, the proposed replacement SGs are acceptable.

3.4.3.8.2.3 Steam System Piping Failure (LAR Section 6.3.3)

Steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of RCS coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause shutdown margin to be lost (for the hot zero power (HZP) cases) such that the reactor core returns to a critical state and generating power after the control rods have been inserted (tripped). The RPS and safety systems are actuated to mitigate the transient and the core is shut down by the boric acid injection into the RCS by the SIS. The steam system piping failure is an ANS Condition IV event. The rupture of a major steam line is the most-limiting cooldown transient. It is analyzed at zero power with no decay heat assumed because decay heat would partly offset the cooldown, and reduce the post-trip return to power.

The MSLB, or steam line rupture, is also analyzed at hot full-power (HFP) to demonstrate that a reactor trip occurs in time to prevent an unacceptable level of fuel damage due to centerline melting. A range of break sizes is analyzed. The larger break sizes are protected by reactor trip signals from the low steam line pressure reactor trip logic, and the smaller break sizes result in reactor trips from the OPΔT reactor trip logic. The most limiting break size is the largest break that results in a reactor trip on the OPΔT reactor trip function.

In performing its analysis, the licensee stated that it assumed the most reactive rod cluster control assembly (RCCA) to be stuck in its fully withdrawn position. If there is a return to power, the highest power level would be found in the core region surrounding the stuck RCCA location and this region would have the highest hot channel factors and lowest DNBRs.

Analysis cases were also considered by the licensee at no load conditions, with and without offsite power available, to verify that the DNBR safety limit is not violated (an ANS Condition II acceptance criterion that is nevertheless met in this event analysis). The limiting MSLB case is the case with offsite power available because the forced primary system flow aids the heat extraction from the core via the blowdown of the affected SG. The licensee explained that the RETRAN-02 computer code was used to calculate the core heat flux and the RCS temperature and pressure resulting from the cooldown. The Standard Thermal Design Procedure (STDP) is used, since the no-load steam line rupture event produces plant conditions that are outside the range of applicability for the RTDP. The VIPRE-01 code was used to calculate the thermal hydraulic conditions, including the DNBR, in the region of the stuck RCCA. The W-3 DNBR correlation is applied.

The results presented by the licensee indicate that both HZP cases produce a low steam line pressure reactor trip and safety injection signal at about 2 seconds after the break, since the loss of offsite power is not assumed to occur until later, at 3 seconds after the break. As expected, the cooldown and subsequent return to power transient is slower when offsite power is assumed to be unavailable. The minimum DNBR, for the limiting HZP case (with offsite

power) is about 1.9, which is well above the safety limit of 1.50 for the W-3 DNBR correlation as listed in Table 6.3-2 of WCAP-16265-P.

The HZP case was considered with offsite power available. RETRAN-02 and VIPRE-01` were also used to calculate the core and RCS responses and thermal hydraulic conditions. In this case, the thermal hydraulic analysis was performed using the RTDP approved methodology.

The resulting minimum DNBR is 1.8, which is greater than the 1.59 safety limit. The maximum fuel centerline linear power is 21.19 kw/ft, which is less than the safety limit of 22.46 kw/ft.

Based on its review of the licensee's analysis of the MSLB, as discussed above, the NRC staff concludes that the licensee's analysis was performed using acceptable analytical models. Because the results presented by the licensee meet the DNBR design basis and fuel centerline linear power criteria, the NRC staff concluded that the plant with the replacement SGs will continue to meet the regulatory requirements and, with respect to the steam line break, the proposed replacement SGs are acceptable.

3.4.3.8.2.4 Loss of External Electrical Load/Turbine Trip (LAR Section 6.3.4)

A major loss of load can result from either a loss-of-external electrical load or from a turbine trip from full power without a direct reactor trip. These events result in a sudden reduction in steam flow. The loss of heat sink leads to pressurization of the RCS and MSS. The ANS Condition II acceptance criteria are applicable to this event: (1) the minimum DNBR must remain above the safety analysis limit, and (2) pressure in the RCS and MSS must be limited to 110 percent of the design pressure. Specific review criteria are specified in SRP Section 15.2.1-5.

The licensee performed the analyses using the RETRAN-02 (Reference 4.6) computer code to determine the plant transient conditions following a total loss of load for both conditions. The reactor was tripped on a high-pressurizer pressure trip signal. Since the pressurizer did not become water-solid, there was no concern with the event escalating to an ANS Condition III SBLOCA, due to a stuck-open PORV.

For the pressure case, the licensee stated that the analysis assumptions included the following: instrumentation uncertainties on power level, initial power level is 102 percent of RTP, the thermal design RCS flow rate of 374,400 gpm, average vessel temperature was 585.4 EF, and RCS pressure was 2220 psia. No credit was taken for the effect of the pressurizer spray or PORVs in reducing or limiting the primary pressure.

For the DNBR case, the RTDP methodology is applied that permits the assumption of NSSS conditions without the addition of instrumentation uncertainties. Initial power level was assumed to be 100 percent of RTP, RCS flow was the minimum measured flow rate of 382,630 gpm, average vessel temperature was 588.4 EF, and RCS pressure was 2250 psia. In order to keep RCS pressure conservatively low, the licensee stated its analysis assumed the operation of automatic pressurizer pressure control (i.e., pressurizer spray and PORVs). The WRB-2 correlation, which uses nominal values that are corrected in the correlation, is the basis for core thermal limits used in the DNBR evaluation.

The licensee used the RETRAN-02 computer code to analyze the RCS and core response to the loss of load. RETRAN-02 approximates the transient value of DNBR based on input from the core thermal safety limits. The core thermal safety limits define the limits of operation in terms of power, temperature, and pressure (at a constant flow) that produce a DNBR limit value that provides reasonable assurance that the fuel would not experience DNB.

The results presented by the licensee for the pressure case indicate that the RCS pressure (2731.6 psia) remained below 110 percent of design pressure value (2748.5 psia) and the MSS steam pressure (1294.0 psia) also remained below 110 percent of the SG shell design pressure

(1318.5 psia). The analysis results for the DNBR case indicate that the minimum DNBR (1.90) remained above the DNBR safety limit of 1.55.

Based on its review of the licensee's analyses of the loss of external electric load, as discussed above, the NRC staff concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff also concludes that the licensee has demonstrated that the minimum DNBR will remain above the safety analysis limit, and the pressure in the RCS and MSS will remain below their design limits for the replacement SGs. Based on this, the NRC staff further concludes that the loss of external electric load/turbine trip analyses will continue to meet applicable regulatory requirements for the replacement SGs.

3.4.3.8.2.5 Loss of Non-Emergency Alternating Current (AC) Power to the Station Auxiliaries/Loss of Normal Feedwater (LAR Section 6.3.5)

Loss of Offsite Power

The loss of non-emergency AC power, an ANS Condition II event, terminates all AC power to the station auxiliaries and trips all RCPs. This causes the RCPs to coastdown, and heat removal by the secondary system to decrease. Also, the reactor and turbine will trip, and the RCS pressure and temperature rise. Following the RCP trip, the RCS flow necessary to remove residual heat is provided by natural circulation, which is driven by the secondary system and the safety-related AFW system. The RPS generates the actuation signals needed to mitigate the transient. The following ANS Condition II acceptance criteria are applied: (1) minimum DNBR must be greater than the safety analysis limit, and (2) pressure in the RCS and MSS must be below 110 percent of the system design pressure. Specific review criteria are contained in SRP Section 15.2.6.

The licensee stated that this transient was analyzed using the RETRAN-02 (Reference 4.6) computer code. From its analysis, the licensee concluded that, for a loss of AC (LOAC) power to the station auxiliaries, the plant response is almost identical to the complete loss of reactor coolant flow (LORCF) event. After the reactor trip, the AFW system removes decay heat and this portion of the transient is similar to the loss of normal feedwater (LONF) event. The RETRAN-02 code results show that natural circulation and the available AFW flow are sufficient to provide adequate core decay heat removal following a reactor trip and RCP coastdown. The pressurizer does not reach a water-solid condition and the pressurizer relief and safety valves would not discharge any water. The RCS and MSS pressures remain below the applicable design limits throughout the transient. The licensee stated that the LOAC event is bounded by the complete LORCF event since the first few seconds of the LOAC transient would be almost identical to the complete LORCF event, during which the reactor trips and prevents the DNBR from falling below the DNBR safety analysis limit.

The NRC staff reviewed the licensee's analysis of the LOAC power to plant auxiliaries and concluded that the licensee's analysis was performed using an acceptable analytical model, as stated above. The NRC staff finds that the licensee has demonstrated that the RPS and safety systems will continue to ensure that the specified fuel design limits are not exceeded, the peak primary and secondary system pressures are not exceeded, and a more serious plant condition is precluded. Based on this, the NRC staff concludes that the plant will continue to meet the regulatory requirements with respect to the LOAC power to the plant auxiliaries for the installation of the replacement SGs, and, therefore, the replacement SGs are acceptable with

respect to the LOAC power to the plant auxiliaries.

LONF Event

The LONF event, an ANS Condition II event, impairs the ability of the plant secondary system to remove heat from the primary side. The loss of heat sink requires the reactor to be tripped and an alternate supply of feedwater to be supplied to the SGs. Following the reactor trip, it is necessary to remove residual heat and RCP heat to prevent RCS pressurization and loss of primary system water inventory through the pressurizer relief and safety valves. If enough RCS inventory is lost, then core damage could occur. Since the reactor is tripped well before the SG heat transfer capability is reduced, thermal margin is not eroded to the point where the DNBR limit may be violated. The RPS provides the protection against a LONF event by way of a reactor trip on low-low SG water level in one or more SGs.

The AFW system is started automatically on SG low-low water level, following a safety injection signal, on loss of offsite power, or on trip of both main feedwater pumps. The LONF analysis should demonstrate that following a loss of normal feedwater the AFW system is capable of removing the stored energy, residual decay heat, and RCP heat. This is demonstrated by showing that the pressurizer does not become water-solid, which could lead to overpressurization of the RCS and a subsequent loss of water from the RCS via a pressurizer pressure relief or safety valve.

The licensee stated that the LONF transient for Callaway is analyzed using the RETRAN-02 computer code (Reference 4.6). The assumptions applied in the analysis are intended to delay the time of reactor trip and to minimize the energy removal capability of the AFW system. The initial power level is assumed to be 102 percent of RTP. The low-low SG water level, which demands the reactor trip, is assumed to be set at 0 percent of narrow range span (NRS). The turbine trip is assumed to occur at the same time as the reactor trip. A conservative core residual heat generation is assumed based on the American Nuclear Society (ANS) 5.1-1979 decay heat model plus 2σ for uncertainties (Reference 4.16). One minute after the low-low SG water level setpoint is reached, AFW system flow (960 gpm) from both motor-driven AFW pumps is initiated with flow split equally among the four SGs. The turbine-driven AFW pump is assumed to be the single failure. Although reactor control systems are not usually assumed to be available, the pressurizer PORVs, pressurizer heaters, and pressurizer sprays are assumed to operate as designed, in order to maximize the pressurizer water level. The LONF cases are analyzed with and without offsite power available. When offsite power is available the RCPs do not coast down, and RCP heat is added to the residual heat that must be removed by the AFW system after reactor trip.

The licensee stated it performed a separate analysis to address the reliability of the AFW system. The analysis is based upon the assumption that only one motor-driven AFW pump is available to feed 2 of the 4 SGs. However, better-estimate initial conditions are applied for power, RCS pressure and temperature, and pressurizer level. The RTS setpoints are assumed to be at their nominal values, and less decay heat (Reference 4.16) is added. The NRC staff agrees that these two analyses permit the licensee to address the FSAR Chapter 15 LONF and AFW system reliability issues separately.

The NRC staff reviewed the licensee’s analyses for the LONF flow transient and concluded that

the licensee's analysis adequately accounted for operation of the plant at the replacement SG design conditions and was performed using an acceptable analytical model. The NRC staff finds also that the licensee has demonstrated that the minimum DNBR safety analysis limit will not be exceeded, since this is a heatup transient and it would not go below the DNBR safety limit of 1.55 during this transient. Furthermore the results indicate that the RCS pressure (approximately 2325 psia) remained below 110 percent of RCS design pressure value (2748.5 psia), and the MSS steam pressure (approximately 1240 psia) also remained below 110 percent of the SG shell design pressure (1318.5 psia). The pressurizer would not become water-solid during this transient and the AFW system capacity is sufficient to dissipate core residual heat, stored energy, and reactor coolant pump heat such that reactor coolant water would not relieve through the pressurizer relief or safety valves. The maximum calculated pressurizer water volumes for the LONF with and without offsite power were 1231 ft^3 and 1425 ft^3 respectively. Both calculated pressurizer volumes are less than the pressurizer volume limit of 1800 ft^3. Based on this, the NRC staff concludes that the plant will continue to meet the regulatory requirements with respect to the LONF event for the replacement SGs and, therefore, the replacement SGs are acceptable with respect to the LONF event.

3.4.3.8.2.6 Feedwater System Pipe Break (LAR Section 6.3.6)

A major feedwater line rupture, an ANS Condition IV event, is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the SGs to maintain shell-side fluid inventory. Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive discharge of steam through the break) or an RCS heatup. Cases that can cause an RCS cooldown are covered by the analysis of the MSLB event, also an ANS Condition IV event. Therefore, a feedwater line rupture is evaluated as one of the events that can cause an RCS heatup.

Analysis of this event demonstrates the ability of the AFW system to remove core decay heat and thereby ensure that the core remains in a coolable geometry. It is inferred that the core remains covered with water (and coolable) by showing that the hot and cold leg temperatures remain subcooled until the AFW system heat removal rate exceeds the RCS heat generation rate (mainly from decay heat). The analysis also demonstrates that the primary and secondary pressures remain within 110 percent of their respective design pressures. Specific review criteria are contained in SRP Section 15.2.8.

The licensee stated that the RETRAN-02 computer code (Reference 4.6) was used to calculate the power transient and the associated temperatures of the reactor coolant at various locations in the RCS. These were compared to the saturation temperature, which is calculated based upon the RCS pressure. The major assumptions of the analysis are selected to conservatively maximize the RCS fluid temperatures and minimize the saturation temperature.

The licensee further stated it analyzed feedwater line ruptures with and without offsite power cases. The system responses following the feedwater line break were similar for both cases as analyzed. The results showed that following a reactor trip, the plant remained subcritical. The pressures in the primary and secondary systems indicate that the RCS pressure (approximately 2320 psia) remained below 110 percent of RCS design pressure value (2748.5 psia) and the MSS steam pressure (approximately 1275 psia) also remained below 110 percent of the SG shell design pressure (1318.5 psia). After the reactor trip, the RCS heats up and pressurizes

until the PORVs open and the heat removal rate, due to steam relief through the main steam safety valves and AFW injection, exceeds the core decay heat plus RCP heat. When this point is reached, temperatures begin to decrease and the adequacy of the AFW system is demonstrated. Since the maximum hot and cold leg temperatures remain below the saturation temperature (by more than 41 °F) throughout the transient, it is demonstrated that the core remains covered and coolable through the transient. This is a heatup transient and it would not go below the DNBR safety limit of 1.55 during this transient.

The NRC staff agrees that the postulated feedwater line rupture analysis indicates that the AFW system capacity is adequate to remove decay and RCP heat, and to prevent uncovery of the reactor core for Callaway as equipped with the replacement SGs. Based on this, the NRC staff concludes that the plant will continue to meet the regulatory requirements with respect to the feedwater system pipe break event for the replacement SGs and, therefore, the replacement SGs are acceptable with respect to the feedwater system pipe break event.

3.4.3.8.2.7 Partial and Complete Loss of Forced Reactor Coolant Flow (LAR Section 6.3.7)

Partial Loss of Forced Reactor Coolant Flow (LAR Section 6.3.7.1)

A partial loss of coolant flow, an ANS Condition II event, may be caused by a mechanical or electrical failure in an RCP motor, a fault in the power supply to the pump motor, or a pump motor trip caused by such anomalies as over-current or phase imbalance. The licensee stated that its partial loss of coolant flow accident analysis postulates a failure that causes two RCPs to coast down (i.e., a fault in the bus that supplies power to two pump motors). This transient is analyzed to demonstrate that the DNBR remains above the safety analysis limit value, and that the peak RCS and MSS pressures remain below 110 percent of their design pressures.

The licensee stated that the RETRAN-02 computer code (Reference 4.6) is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE-01` computer code (Reference 4.7) is then used to calculate the hot-channel heat flux transient and DNBR based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN-02. This event is analyzed following the RTDP (Reference 4.9) that assumes initial reactor power, pressurizer pressure, and RCS temperature are at their nominal values. Minimum measured flow is also assumed. Assumptions are made such that the core power is maximized during the initial part of the transient when the minimum DNBR is reached. As explained in Section 3.4.1 of this SE, these computer codes are acceptable for these calculations for Callaway.

The analysis results presented by the licensee indicate that the minimum DNBR is 1.90 (thimble cell) and 1.94 (typical cell). This is greater than the safety analysis DNBR limit of 1.55 (thimble cell) and 1.59 (typical cell) during the transient. Based on this, the NRC staff concludes that the regulatory acceptance criteria for the partial LORCF event are satisfied, including no fuel failures are predicted. Based on these results, the NRC staff finds that the replacement SGs are acceptable with respect to the partial LORCF event.

Complete Loss of Forced Reactor Coolant Flow (LAR Section 6.3.7.2)

A complete loss of forced reactor coolant flow, an ANS Condition III event, could result from a

simultaneous loss of electrical supplies to all RCPs. A decrease in RCS flow occurring while the plant is at power could result in a degradation of core heat transfer and a subsequent increase in fuel temperature. Accompanying fuel damage could then result if specified acceptable fuel design limits are exceeded during the transient. RPS and safety systems are actuated to mitigate the transient. The ANS Condition II acceptance criteria are conservatively applied to the analysis of this event. The minimum DNBR must remain above the safety analysis limit, and pressure in the RCS and MSS must stay below 110 percent of the design pressures. Specific review criteria are contained in SRP Section 15.3.1-2.

The licensee stated it used the RTDP methodology (Reference 4.9), the RETRAN-02 code (Reference 4.6) and VIPRE-01` code (Reference 4.7) to reanalyze the complete loss of reactor coolant flow at the replacement SG design conditions. For the complete loss of flow event, the licensee analyzed the following two transient cases: (1) a loss of power to all pumps and (2) an underfrequency condition. The VIPRE-01` code analyses for these scenarios confirmed that the minimum DNBR values 1.76 (thimble cell) and 1.79 (typical cell) were greater than the safety analysis limit values of 1.55 (thimble cell) and 1.59 (typical cell). The peak RCS and MSS pressures remained below their respective limits (2748.5 psia for RCS and 1318.5 psia for MSS) at all times. The NRC staff concludes that the results of the licensee's analyses demonstrate that the regulatory acceptance criteria for these events were satisfied.

The NRC staff reviewed the licensee's analyses of the complete loss of reactor coolant flow and concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff finds that the licensee demonstrated that (1) the RPS and safety systems will continue to ensure the minimum DNBR will remain above the safety analysis limits and (2) the pressure in the RCS and MSS will be maintained below 110 percent of the system design pressures. Based on this, the NRC staff concludes that the plant will continue to meet the regulatory requirements with respect to the complete loss of reactor coolant flow for the replacement SGs and, therefore, the replacement SGs are acceptable with respect to the complete loss of reactor coolant flow.

3.4.3.8.8 RCP Shaft Seizure (Locked Rotor)/RCP Shaft Break (LAR Section 6.3.8)

The locked rotor accident, an ANS Condition IV event, can result from an instantaneous seizure of the RCP rotor or a break of the RCP shaft. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a low flow signal. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer that could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor

seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, the RPS and safety systems are actuated to mitigate the transient. The ANS (Reference 4.14) Condition IV event acceptance criteria are applied as follows: (1) RCS pressure should be below the designated limit, (2) coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2700 EF and 16 percent by weight, respectively, and (3) activity release is such that the calculated doses meet the 10 CFR Part 100 guidelines.

The licensee stated that it used the RETRAN-02 (Reference 4.6), and VIPRE-01` (Reference 4.7) computer codes with the RTDP (Reference 4.9) methodology to analyze this accident. The

licensee performed the analyses using the RETRAN-02 computer code to calculate the loop and core flow transients, nuclear power transient, and RCS pressure and temperature transients. The VIPRE-01` computer code was then used to calculate the thermal behavior of the fuel rods located at the core hot spot including the rods-in-DNB (i.e., rods in departure from nucleate boiling) using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN-02. The cases analyzed to determine rods-in-DNB utilized the RTDP methodology. Rods-in-DNB cases are analyzed twice, once with continuous operation of the intact RCPs, and once with a loss of power to the intact RCPs to determine RCS pressure and peak cladding temperature. The results of the analyses show that the peak RCS pressure is 2559.5 psia (RCPs without power case), which is less than the acceptance criterion of 2748.5 psia. The PCT is 1790 EF which is considerably less than the limit of 2700 EF for this event. The zirconium-water reaction at the hot spot was 0.30 percent by weight, meeting the criterion of less than 16-percent zirconium-water reaction. The total percentage of fuel rods calculated to experience DNB was less than 5 percent (rods-in-DNB case). The total percentage of fuel rods in DNB was less than that assumed in the radiological dose evaluation. Thus, the acceptance criteria was satisfied for this accident.

The NRC staff reviewed the licensee’s analyses of the locked rotor and pump shaft break events and concluded that the licensee’s analyses were performed using acceptable analytical models. Based on this, the NRC staff concludes that the plant will continue to meet the regulatory requirements for the replacement SGs with respect to the RCP locked rotor and shaft break accidents and, therefore, the replacement SGs are acceptable with respect to the RCP locked rotor and shaft break accidents.

3.4.3.8.9 Uncontrolled Rod Cluster Control Assembly (RCCA) Withdrawal from Subcritical or Low Power Startup Condition (LAR Section 6.3.9)

This ANS Condition II event is characterized by the insertion of positive reactivity to the reactor core due to the inadvertent withdrawal of an RCCA bank while the plant is in a subcritical or low power startup condition. The Uncontrolled RCCA Withdrawal from Subcritical or Low Power Startup Condition is a core power excursion transient that triggers automatic RPS features that are derived from measured core transient parameters. As such, it is not sensitive to secondary-side conditions or SG performance parameters. In fact, analyses of this event do not model SGs. The licensee stated that, based on this, it has not re-analyzed this event for Callaway for the replacement SGs and the analyses in the licensing basis for Callaway remains applicable to Callaway with the installation of the replacement SGs. Upon review of the licensee's application, the NRC staff agrees with the licensee’s conclusion that this event would not be affected by the replacement SGs and, therefore, did not need to be re-analyzed for the replacement SGs.

3.4.3.8.10 Uncontrolled RCCA Withdrawal at Power (LAR Section 6.3.10)

Unlike the Uncontrolled RCCA Withdrawal from Subcritical or Low Power Startup Condition, the Uncontrolled RCCA Withdrawal at Power, also an ANS Condition II event, is affected by the secondary system, since the secondary system is relied upon to remove heat from the primary system while the plant is at power. If the RCCA bank withdrawal event is not terminated by manual or automatic action, the power mismatch and resultant temperature rise could cause DNB and/or fuel centerline melt, and RCS pressure could increase to a level that could challenge the integrity of the RCS pressure boundary or the MSS pressure boundary.

The reactor may be tripped by the RPS on power-range nuclear instrument (NI) high neutron flux, OTΔT, OPΔT, high pressurizer pressure, or high pressurizer water level. The Uncontrolled RCCA Withdrawal at Power event analysis credits reactor trips from only the power-range NI high neutron flux and OTΔT trip signals. Many cases are considered: at initial power levels of 10, 60, and 100 percent of RTP, with minimum reactivity feedback (i.e., with a moderator temperature coefficient (MTC) of reactivity of 0 pcm/EF at full power, and +5 pcm/EF at 60 percent and 10 percent power), and maximum reactivity feedback (i.e., a conservatively negative MTC), and with a range of reactivity insertion rates, from very small to greater than that which would result from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservatively high speed (72 steps/minute). Analysis of the large number and variety of cases tests the dynamic response of the OTΔT trip, to verify that the trip signal will prevent DNB over a wide range of possible operating and transient conditions, given delays associated with temperature measurement, signal processing, and rod motion. The range of cases selected is consistent with SRP Section 15.4.2 (Reference 4.1).

The results presented by the licensee for Callaway are provided via representative transients and plots of the minimum DNBR values, compiled from the analyzed cases, versus the reactivity insertion rate. For the slower reactivity insertion rates, the OTΔT trip signal is generated before the power-range NI high neutron flux trip signal. For the faster reactivity insertion rates, the power-range NI high neutron flux trip signal occurs first. The worst case, with the lowest minimum DNBR, typically occurs at the reactivity insertion rate for which both signals are generated at about the same time (i.e., in the region where the first trip signal received shifts from one protection logic to the other).

For the uncontrolled RCCA withdrawal at power event, the licensee stated that the minimum DNBR is calculated by RETRAN-02, based upon core limit curves (Figure 6.3-1 of WCAP-16265) that are drawn from analyses performed with a more detailed core thermal-hydraulic model (VIPRE-01`). The core limits are the loci of points, in the operating space defined by core power level, vessel average temperature, and RCS pressure, for a given core flow rate, that trace the conditions under which the DNBR would equal a specified limit value, which protects 95 percent of the fuel, both typical and thimble cells, from undergoing DNB, with a 95 percent confidence level. This DNBR limit value is 1.55. RETRAN-02 calculates the transient RCS core power level, vessel average temperature, and RCS pressure, and based on these parameters uses the core limits to calculate a DNBR transient. This procedure is valid for transients in which flow rate does not change since the core limits are defined only for a constant flow rate.

The minimum DNBR from the RETRAN-calculated DNBR transient is compared to the DNBR safety limit of the core limit curves. For the Callaway uncontrolled RCCA at power event, the analysis results indicate that the minimum DNBR of 1.572 occurs during the case that is analyzed at 60 percent initial power with minimum reactivity feedback and a constant reactivity insertion rate of 12.5 pcm/second. This result is greater than and, therefore, satisfies the DNBR safety limit of 1.55.

The maximum core heat flux, at 117.1 percent of RTP, occurs during the case that is analyzed at full power with maximum reactivity feedback and a constant reactivity insertion rate of 34 pcm/second. This is 1.4 percent below the safety limit (118.5 percent of RTP). The maximum MSS pressure, 1,283.8 psia, occurs during the case that is analyzed at 10 percent of

RTP with maximum reactivity feedback and a constant reactivity insertion rate of 14 pcm/second. This is 34.7 psi below the MSS safety limit of 1,318.5 psia.

The uncontrolled RCCA withdrawal at power event analysis also verifies that the event would not develop into an ANS Condition III SBLOCA by showing that the pressurizer does not become water-solid during any of the cases analyzed. This is demonstrated by analyzing a case with a very slow reactivity insertion rate. Given the slow reactivity insertion rate, a reactor trip would not be demanded for a long time. While, the pressurizer water level increases, and approaches the water-solid condition, level drops eventually due to coolant shrinkage following the reactor trip (usually on OTΔT). The high pressurizer water level trip logic is available; but not credited in the analyses to demand the reactor trip.

The NRC staff reviewed the licensee's analyses of the Uncontrolled RCCA Withdrawal at Power event and concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff also concludes that the plant will continue to meet the regulatory requirements for the replacement SGs with respect to the uncontrolled RCCA

withdrawal at power event and, therefore, the replacement SGs are acceptable with respect to the uncontrolled RCCA withdrawal at power event.

3.4.3.8.11 RCCA Misoperation (LAR Section 6.3.11)

The RCCA misoperation events are ANS Condition II events that include incidents such as the following:

- Statistically misaligned full-length RCCA
- Withdrawal of a single RCCA
- One or more dropped full-length RCCAs
- A dropped full-length RCCA bank

The above incidents are transients that are driven by core reactivity and nuclear flux responses to changes in rod positions. As such, they are not sensitive to secondary-side (i.e., SG) conditions.

For the first two events above, the statistically misaligned RCCA, and the withdrawal of a single RCCA, the SGs are not explicitly modeled in the incidents.

For the last two events above, one or more dropped full-length RCCAs, and a dropped full-length RCCA bank, are addressed by way of a generic statepoint analysis that was performed in 1986 using the LOFTRAN code to bound a number of four-loop PWRs. The generic dropped RCCA statepoints are evaluated in each cycle as part of the reload safety evaluation process in order to demonstrate that the applicable DNB design basis is satisfied. The licensee stated that they will be evaluated based on cycle-specific data prior to the installation of the replacement SGs, which is scheduled for fall of 2005, and these generic statepoints have been confirmed to remain valid for the replacement SGs. Based on this, the licensee stated that it did not re-analyze these events for the replacement SGs.

Based on its review of the licensee's application, the NRC staff agrees with this approach by the licensee for the RCCA misoperation events for the replacement SGs and concludes that the

replacement SGs are acceptable with respect to these events.

3.4.3.8.12 Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in the Boron Concentration in the RCS (LAR Section 6.3.12)

As the result of operator error or CVCS malfunction, unborated water can be added to the RCS that would increase core reactivity until the CVCS flow is terminated by the operator or shutdown margin is lost. Boron dilution of the reactor core is a manual operation, with administrative controls and procedures that limit the rate and duration of dilution flow. Analyses of this event would verify that the CVCS system dilution rate is low enough to provide the operator with sufficient time after indication through alarms and instrumentation to stop an unplanned dilution before the shutdown margin is lost.

Analysis of this event is basically a calculation of how long it takes for a constant dilution rate to erode the available shutdown margin. The key parameters of interest, therefore, are CVCS flow rate and mixing volume. The replacement SGs would affect this event analysis insofar as they are part of the active mixing volume in the RCS. Since the replacement SGs are larger than the original SGs, the mixing volume would also be larger. Given the same CVCS flow rate, and the same shutdown margin, then the time to dilute away the shutdown margin is expected to be longer. Therefore, the licensee states that the current licensing basis analyses, which are based upon the original SGs, would bound analyses performed using the new larger replacement SG volumes.

Based on its review of the licensee's application, the NRC staff agrees with the licensee that this event for the replacement SGs is bounded by the current licensing basis analyses for the original SGs and concludes that the replacement SGs are acceptable with respect to these events.

3.4.3.8.13 Spectrum of RCCA Ejection Accidents (LAR Section 6.3.13)

This accident is described as a mechanical failure of a CRDM pressure housing that causes ejection of an RCCA and drive shaft. This creates an SBLOCA in the vessel head and causes a rapid reactivity insertion possibly with an adverse core power distribution that could lead to localized fuel rod damage. A range of break sizes, initiated from zero- or full-power conditions, is analyzed for the core reactivity response. The SBLOCA aspects are evaluated separately.

Since these transients are driven by core reactivity and nuclear flux responses to the ejected RCCA they are not sensitive to secondary-side conditions and SGs are not modeled in the analyses.

The licensee has not re-analyzed this event for the replacement SGs. Instead, the licensee states that the existing analysis of record for this event remains valid. Based on its review of the licensee's application, the NRC agrees with this conclusion and concludes that the replacement SGs are acceptable for these transients.

3.4.3.8.14 Inadvertent Emergency Core Cooling System (ECCS) Actuation at Power (LAR Section 6.3.14)

An inadvertent actuation of the ECCS at power event, an ANS Condition II event, could be

caused by operator error or a false electrical actuating signal. Actuation of the ECCS starts the charging pumps that inject borated water from the refueling water storage tank (RWST) into the cold leg of each RCS loop. The safety-injection pumps also start automatically but provide no flow when the RCS is at normal pressure.

The inadvertent ECCS actuation-at-power event adds water to the RCS until the ECCS is shut off by the operator. This event could develop into a more serious event, an ANS Condition III SBLOCA, if the pressurizer fills and a pressurizer relief or safety valve opens and fails to reseat. This would be a violation of an ANS Condition II acceptance criteria.

As water is added to the RCS, the RCS pressurizes and the pressurizer water level increases. If the pressurizer PORVs are available, they will lift and relieve steam from the RCS. If the pressurizer is water-solid, then the PORVs will relieve water. Opening at least one PORV would be sufficient to limit the RCS pressure to less than the opening setpoints of the PSVs. The analysis acceptance criterion is to prevent the opening of the PSVs, since they're not qualified for water relief and could be damaged by not fully re-seating. Should the PSVs lift, and relieve water, they would be assumed to stick open, and thereby create an SBLOCA at the top of the pressurizer.

The licensee stated that its analysis credits the use of the PORVs to prevent the opening of the PSVs. Operation of the PORVs to mitigate the inadvertent ECCS actuation at-power event is allowable (Reference 4.11), since the licensee has demonstrated to the NRC staff that the PORVs at the Callaway plant are qualified for water relief and equipped with Class 1E automatic control circuitry (Reference 4.10).

The event is analyzed at Callaway to demonstrate that sufficient time is available for appropriate operator action to preclude the opening of PSVs with the pressurizer in a water-solid condition. The appropriate operator actions consist of making the PORVs available (i.e., opening any block valves that may be closed) and terminating the charging flow. The reactor is tripped by the safety injection signal at the initiation of the event. The ECCS flow causes the pressurizer level to increase throughout the transient. At 6 minutes into the transient, the analysis assumes that the normal charging pump flow is terminated by the operator. The pressurizer becomes water solid shortly before 9 minutes into the transient. At 9 minutes into the transient, it is assumed that appropriate operator actions have been taken to assure that at least one pressurizer PORV is available for pressure relief. The assumed operator action times are supported by simulator test results (Reference 4.10). The PORVs eventually open and cause the RCS to depressurize. The PSV opening setpoint is not reached at any time during the transient.

The NRC staff has reviewed the licensee's analyses of the inadvertent ECCS actuation at-power event and concludes that the licensee's analyses were performed using acceptable analytical models. Because the PSV opening setpoint is not reached at any time during the transient for the replacement SGs, the NRC staff concludes that the replacement SGs are acceptable with respect to the inadvertent ECCS actuation-at-power event.

3.4.3.8.15 CVCS Malfunction that Increases Reactor Coolant Inventory (LAR Section 6.3.15)

This event, which resembles the previous inadvertent operation of ECCS accuation-at-power event, is addressed in FSAR Section 15.5.1 and in Section 3.4.3.8.14 of this SE. Both this

event and the previous event rely upon operator action to terminate the event by shutting off the charging flow. As in the inadvertent operation of the ECCS at power event, the licensee showed that the PSVs for the current event would not open and relieve water as long as the PORVs are available.

Based on the above, the licensee did not re-analyze this event for the replacement SGs. Based on its review of the licensee's application, the NRC staff agrees with the licensee that a re-analysis of this event is not necessary for the replacement SGs. Based on this, the NRC staff concludes that the replacement SGs are acceptable with respect to increases in RCS inventory resulting from a CVCS malfunction.

3.4.3.8.16 Inadvertent Opening of a Pressurizer Safety and Relief Valve (LAR Section 6.3.16)

The inadvertent opening of a PORV results in a decrease in the RCS water inventory and pressure. The inadvertent opening of a pressurizer PORV is classified as an ANS Condition II event, and the failure of a PSV is classified as an ANS Condition III event. A reactor trip normally occurs during these events due to low pressurizer pressure or OTΔT. The accidental depressurization of the RCS, an ANS Condition II event, would be postulated to occur as the result of an inadvertent opening of a PORV. Since a PSV has about twice the steam relief capacity of a PORV, its opening would cause a more rapid depressurization of the RCS. The rapidly decreasing RCS pressure causes an erosion of thermal margin that could eventually lead to a demand for a reactor trip from the OTΔT RPS logic. In fact, this event is one of the events used to determine the calculated setpoints for the OTΔT trip signal.

The licensee has conservatively evaluated the accidental depressurization of the RCS associated with an inadvertent opening of a PSV, while adhering to the more restrictive acceptance criteria of an ANS Condition II event of ensuring the DNB design basis is met. Specific review criteria are contained in SRP Section 15.6.1 (Reference 4.1).

The accidental depressurization transient is analyzed with the NRC-approved RETRAN-02 code (Reference 4.6). The code simulates the core neutron kinetics; RCS conditions, pressurizer conditions; operation of the pressurizer PORVs and PSVs, and pressurizer spray; and replacement SG conditions and safety valves. The code computes pertinent plant variables, including temperatures, pressures, and power level. This accident analysis is performed in accordance with the RTDP methodology in order to calculate the minimum DNBR during the transient.

The licensee stated that its analysis results indicate that the inadvertent opening of a pressurizer PSV would not lead to a violation of the DNBR. The minimum DNBR value, calculated by RETRAN-02, is 1.86, which is above the comparable DNBR safety limit value of 1.55. Therefore, the licensee concluded that no fuel damage is predicted, and the ANS Condition II acceptance criteria are satisfied.

The NRC staff has reviewed the licensee’s analyses of the inadvertent opening of a pressurizer PORV event and concluded that the licensee’s analyses were performed using acceptable analytical models. The NRC staff further concluded that the licensee demonstrated that the RPS and safety systems will continue to ensure that the specified acceptable fuel design limit will not be exceeded. This is a depressurization event and the RCS pressure limits would not be challenged. Therefore, the NRC staff concludes that the replacement SGs are acceptable

with respect to the inadvertent opening of a PSV or a pressurizer PORV event.

3.4.3.8.17 Anticipated Transients Without Scram (ATWS) (LAR Section 6.3.17)

ATWS events are defined as anticipated operational occurrences or ANS Condition II events (e.g., loss of normal feedwater, loss of condenser vacuum, or loss of offsite power) during which a required reactor trip is not executed due to a common mode failure in the RPS. Without the reactor trip, certain anticipated transients could produce DNBRs, and peak primary and secondary system pressures that violate the ANS Condition II acceptance criteria. ATWS events are not in the design basis for a plant, and are not subject to the ANS Condition II acceptance criteria. The acceptance criteria for ATWS analyses are in the basis for the ATWS rule, 10 CFR 50.62, which requires Westinghouse-designed PWRs (such as the Callaway plant) to install actuation circuitry that is separate and diverse from the RTS, automatically initiate the AFW system, and trip the turbine for conditions indicative of an ATWS. Installation of the NRC-approved ATWS Mitigating System Actuation Circuitry (AMSAC) complies with the ATWS rule and, because AMSAC has been installed at Callaway, the requirements of 10 CFR 50.62 have been satisfied.

The basis for the ATWS rule and the AMSAC design are supported by generic sensitivity studies submitted to the NRC by Westinghouse in 1979 (Reference 4.12). These analyses were performed in response to guidelines issued by the NRC staff in 1978 (Reference 4.13). These guidelines contain the basis for the ATWS rule, including acceptance criteria for the ATWS analyses. The principal concern with ATWS events is the possibility of breaching the RCPB from overpressure. The acceptance criterion for ATWS analyses specify that RCS pressure must not produce a stress in the RCPB that exceeds Service Level C, as defined in the ASME Nuclear Power Plant Components Code, Section III. For Westinghouse plants, this translates to 3200 psig (or 3215 psia). There is also an acceptance criterion pertaining to DNB; but in practice, there are no ATWS analyses that significantly approach the DNBR limit.

The loss of load/turbine trip (LOL/TT) and LONF ATWS events result in the highest RCS pressure transients (References 4.12 and 4.13). Therefore, the licensee has re-analyzed these two events, in order to verify that the analytical basis for the final ATWS rule continues to be satisfied for the replacement SGs. That is, the re-analyses were performed in order to incorporate the design and performance characteristics of the replacement SGs into the ATWS analysis model since the generic analyses (Reference 4.12) were based upon Westinghouse SG models.

The licensee reported that the peak RCS pressure result from the LOL/TT analysis is 3177 psia and the peak RCS pressure result from the LONF ATWS analysis is 2973 psia. Both these peak pressure results are below the 3215 psia acceptance criterion. The licensee stated, in response to a request for additional information, that the maximum allowed differential pressure across the tubes or the tube sheet is 2980 psi. The maximum allowed differential pressure across the tubesheet and tubes of the replacement SGs, matches or exceeds 2980 psi. The maximum primary to secondary differential pressure for the loss of load ATWS analysis is 1943 psi; and the maximum primary to secondary differential pressure for the loss of normal feedwater ATWS analysis is 2630 psi. For both cases, the maximum differential pressure does not exceed the 2980 psi limit.

Based on the above, the NRC staff concludes that the licensee has demonstrated that the analytical basis for the final ATWS rule continues to be met at Callaway for operation of the replacement SGs. Based on this, the NRC staff further concludes that the ATWS analysis is acceptable for the replacement SGs.

3.4.3.8.18 Station Blackout (SBO)

SBO refers to a complete loss of AC power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the loss of offsite power concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from "alternate AC sources" (AACs). The staff's review focused on the impact of the replacement SG conditions on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63 and specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2.

The licensee did not submit any information for an SBO event in its application. In response to an NRC staff RAI, the licensee discussed the impact of the replacement SG conditions on the plant's coping capability during an SBO event. The SBO minimum required coping duration for Callaway is 4 hours. It is based on an evaluation of the offsite power design characteristics, emergency AC power system configuration, and emergency diesel generator reliability in accordance with the evaluation procedure outlined in NUMARC 87-00 (Reference 4.18). The current analysis of record indicates that the current condensate storage tank (CST) inventory requirement for decay heat removal is 158,000 gallons during the 4-hour SBO coping period. This requirement is significantly below the minimum CST usable inventory of 281,000 gallons, which is currently specified in TS 3.7.6. The SGs must remove decay and sensible heat. The only impact from the replacement SGs to the SBO coping assessment is the increase in sensible heat from the increased SG metal mass. The overall impact from increased sensible heat due to the replacement SGs is minimal, and the CST usable inventory is so large in comparison to the total decay heat requirement, the licensee concluded that the effects of the replacement SGs are bounded by the current analysis of record for the original SGs.

The staff reviewed the licensee's assessment of the effects of the replacement SG conditions on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's current licensing basis. Based on this review, the NRC staff agrees with the licensee's assessment (stated above) of the impact of the replacement SGs on SBO and, therefore, concludes the replacement SGs are acceptable with respect to SBO.

3.4.3.9 SGTR Transient (LAR Section 6.4)

The licensee has re-analyzed the design basis SGTR event to demonstrate that Callaway will continue to meet the regulatory requirements for this DBA after installation of the replacement SGs. The analysis is based upon a full-power Tavg operating window of 570.7 °F to 588.4 °F, a main feedwater temperature window of 390 °F to 446 °F, and a SG tube plugging level of up to 5 percent.

The SGTR, an ANS Condition IV event, would transfer radioactive RCS coolant to the shell side of the SG with the ruptured tube, and ultimately, into the atmosphere. Therefore, the SGTR

analysis is performed to show that the resulting offsite radiation doses will stay within the allowable guidelines of 10 CFR Part 100.

The following two SGTR cases were analyzed with respect to radioactive releases to the environment:

1. An SGTR with an SG atmospheric relief valve (ARV) that is assumed to be stuck open for 20 minutes. This ARV is connected to the SG containing the ruptured tube.

2. An SGTR with an AFW flow control valve assumed to be failed open. This AFW flow control valve is connected to the SG containing the ruptured tube. The relatively high AFW flow increases the likelihood that the SG containing the ruptured tube will overfill and result in water relief through its safety valve. The safety valve is assumed to partially stick open, following water relief, with a small effective flow area (Reference 4.15).

The SGTR was analyzed using the RETRAN-02 (Reference 4.6) computer code and includes simulation of operator actions for post-event recovery based upon EOPs. The resulting primary-to-secondary break flow and atmospheric releases are used to calculate the radiological consequences of the accident.

The replacement SG tubes are slightly larger than the original SG tubes. Therefore, the tube break flow is expected to be larger for the replacement SGs. The NRC staff's review of the tube break flow assumptions indicates that the replacement SG tube break flow continues to be conservatively high.

The NRC staff has reviewed the licensee's analyses of the SGTR events and concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has assumed operation of the RPS and safety systems, and appropriate manual actions, to calculate the mass releases necessary to determine the radiological consequences of the SGTR. Therefore, the NRC staff finds that the SGTR event analysis, provided by the licensee, is acceptable to determine the radiological consequences of the SGTR for the replacement SGs. The radiological consequences of the SGTR are addressed in Section 3.5.3 of this SE.

3.4.3.10 Nuclear Fuel (LAR Section 7)

The replacement SGs do not involve any changes to the nuclear fuel design. Section 7, Nuclear Fuel, of WCAP-16265 describes the core thermal-hydraulic analyses and evaluations performed in support of the installation of the replacement SGs.

Most key thermal hydraulic parameters were unchanged because of the replacement SGs. Reactor power (3565 MWt), core average linear power (5.69 kw/ft), thermal design flow rate (93,600 gpm/loop), RCS minimum measured flow rate (95,660 gpm/loop), best estimate core bypass flow (4.8 percent), system pressure (2250 psia), $F_{\Delta H}$ limit (1.65), and fuel design (ZIRLO Clad, 17x17 V+) all remained the same. The lower end of the RCS vessel Tavg range was reduced from 583.4 °F to 570.7 °F, and the lower end of the RCS core HFP inlet temperature range dropped from 551.5 °F to 538.2 °F. Since the upper ends of the vessel Tavg and core inlet temperature ranges were assumed in the fuel rod design analysis, the NRC staff

concludes that the current fuel rod design analysis performed with an NRC-approved methodology remains valid for the replacement SGs.

3.4.3.11 TS Changes

The following are the proposed changes to TSs that are addressed in the reactor systems review of the licensee's application:

(1) TS 2.1.1.1, SLs

The licensee proposed to replace Figure 2.1.1-1, reactor core safety limits, with a new figure to account for changes in plant operating conditions due to the performance characteristics of the replacement SGs. Reactor trip setpoints, calculated by the OTΔT and OPΔT reactor trip logic were shown by the results of safety analyses to be effective in protecting the fuel from experiencing DNB and centerline melting, respectively. These are discussed in Section 3.1 of this SE. Therefore, the NRC staff finds the new core limits figure acceptable.

(2) TS Table 3.3.1-1, RPS Instrumentation

Notes 1 and 2 to TS Table 3.3.1-1 lists the parameters T' and T" which are being revised to both state that they are "the nominal Tavg at RTP, $\leq$ 585.3 °F." These terms are used in the OTΔT and OPΔT trip functions in a similar manner, to develop a variable reactor trip setpoint dependent upon the measured RCS Tavg. Both T' and T" refer to the nominal RCS Tavg at full power conditions (i.e., 100 percent RTP). Westinghouse performed the analyses for the replacement SGs to determine the nominal full power RCS Tavg. Because the proposed wording for T' and T" is consistent with the licensee's plan to operate within a defined range of Tavg values at RTP for determining the LSSS for automatic protective devices related to

variables on which safety limits have been placed, the NRC staff concludes that the proposed change meets 10 CFR 50.36 and is, therefore, acceptable.

(3) TS 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits (DNB Parameters)

The licensee proposed to revise the safety analysis limits for pressurizer pressure and RCS average temperature. The pressurizer pressure will be changed from $\leq$ 2220 psig to $\leq$ 2223 psig, and RCS average temperature will be changed from $\leq$ 592.6 EF to $\leq$ 590.1 EF. These proposed changes reflect the revised safety analysis limits for the replacement SGs while maintaining allowances for measurement uncertainty for instrument loop indications that are unaffected by the proposed changes. Because the analyses demonstrate that the proposed values are conservative and provide the lowest functional capability or performance level of equipment required for safe operation of the facility, the NRC staff concludes that these changes meet 10 CFR 50.36 and are, therefore, acceptable.

(4) TS Table 3.7.1-1, MSSVs

The licensee proposed to revise TS Table 3.7.1-1 to decrease the maximum allowable power for 3 operable MSSVs per SG from $\leq$ 49 percent of RTP to $\leq$ 45 percent RTP to reflect the replacement SGs and associated safety analyses. The maximum allowable power for 4 and 2

operable MSSVs per SG are not being changed by this amendment. The licensee stated that Westinghouse performed a revised LOL/TT trip analysis covering operation with inoperable MSSVs for the replacement SG conditions. The results of the analysis indicate that three operable MSSVs per SG could not support operation above 45 percent RTP. Because this change provides the lowest functional capability or performance level of equipment required for safe operation of the facility, the NRC staff concludes that the proposed change to TS Table 3.7.1-1 meets 10 CFR 50.36 and is, therefore, acceptable.

(5) TS SRs 3.4.5.2 and 3.4.6.2, 3.4.7.2, and LCO 3.4.7

SRs 3.4.5.2 (Mode 3) and 3.4.6.2 (Mode 4) require the verification of the SG secondary side narrow range water levels are greater than the percent of required RCS loop that is specified in the SRs. The licensee proposed to increase the percentage from 4 percent to 7 percent for the replacement SGs because the new percentage of required RCS loop is the instrument reading corresponding to the top of the SG tubes for the replacement SGs. The bases for the specified percentage of required RCS loop is to maintain sufficient water in the SG secondary side to have a heat sink for decay heat during plant shutdown in Modes 3 and 4 when the RCPs provide forced circulation for heat removal during plant heatup and cooldown. The surveillance test interval (STIs) for these SRs are not being changed by the amendment.

For LCO 3.4.7 and SR 3.4.7.2 (Mode 5), the secondary side wide range water level of at least two SGs is required to be greater than a specified percentage. The LCO states the percentage and the SR verifies that the water in the required SGs is greater than the specified percentage. The licensee proposed to increase the percentage from 66 percent to 86 percent for the replacement SGs because the new percentage of required RCS loop is the instrument reading corresponding to the top of the SG tubes for the replacement SGs. The bases for the specified percentage of the required SGs is to maintain an alternate decay heat removal method by way of natural circulation in Mode 5 in the event that a second residual heat removal (RHR) loop is not operable in Mode 5. The STI for SR 3.4.7.2 is not being changed by the amendment.

The above percentages are different in (1) SRs 3.4.5.2 and 3.4.6.2, and (2) LCO 3.4.7 and SR 3.4.7.2 because the first set of SRs are based on the SG narrow range water level instruments and the second set of LCO and SR are based on the SG wide range water level instrumentation.

The licensee has stated in its application that the percentages listed in the proposed changes to SRs 3.4.5.2 and 3.4.6.2, 3.4.7.2, and LCO 3.4.7 are to require that the replacement SG tubes are covered in Modes 3, 4, and 5. In the identified changes to the TS Bases for these SRs and LCO, it is clear that the proposed changes to 7 percent and 86 percent are to require sufficient water inventory in the replacement SGs for Modes 3, 4, and 5. Because these changes assure that the necessary quality of components is maintained such that facility operation will be within the LCO and that the lowest functional capability or performance levels of equipment required for the safe operation of the facility will be met, the NRC staff concludes that the proposed percentage changes to SRs 3.4.5.2 and 3.4.6.2, 3.4.7.2, and LCO 3.4.7 meet 10 CFR 50.36 and are, therefore, acceptable.

3.4.4 Conclusions

In this section of the SE, the NRC staff reviewed the licensee’s evaluations, analyses and

proposed TS changes to support operation of Callaway under the proposed installation of the replacement SGs with respect to a reactor systems review. Based on this review, the NRC staff finds that the supporting safety analyses were performed with NRC-approved computer codes and methods; the input parameters of the analysis adequately represent the plant conditions for the replacement SGs assumed in each analysis; and the analytical results are within the applicable acceptance criteria. Based on this, the NRC staff concludes that the licensee's supporting analyses are acceptable. The NRC staff also finds that the proposed TS changes discussed in this evaluation adequately reflect the results of the acceptable supporting analysis, and, therefore, conclude that the proposed TSs changes, as discussed in Section 3.4.3.11 of this SE are acceptable for the replacement SGs.

3.5 Dose Consequences Review for DBAs

3.5.1 Introduction

By its application dated September 17, 2004, the licensee requested changes to the TSs to support the installation of replacement SGs during refueling outage 14 in the fall of 2005. Specifically, the proposed changes would revise the following TS:

- TS 2.1.1, "Reactor Core Safety Limits"
- TS 3.3.1, "Reactor Trip System (RTS) Instrumentation"
- TS 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation"
- TS 3.4.1, "RCS Pressure, Temperature, and DNB Limits"
- TS 3.4.5, "RCS Loops - MODE 3"
- TS 3.4.6, "RCS Loops - MODE 4"
- TS 3.4.7, "RCS Loops - MODE 5, Loops Filled"
- TS 3.4.13, "RCS Operational Leakage"
- TS 3.7.1, "Main Steam Safety Valves"
- TS 5.5.9, "Steam Generator (SG) Program"
- TS 5.5.16, "Containment Leakage Rate Testing Program," and
- TS 5.6.10, "Steam Generator Tube Inspection Report"

3.5.2 Regulatory Evaluation

This section of this SE addresses the impact of the proposed changes on previously analyzed DBA radiological consequences and the acceptability of the revised analysis results. The regulatory requirements are the following:

- The accident dose guidelines in 10 CFR 100.11,

- Accident-specific criteria in Section 15, "Accident Analysis," of the Standard Review Plan (SRP) in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," and

- 10 CFR Part 50 Appendix A, GDC 19, "Control Room," as supplemented by SRP Section 6.4, "Control Room Habitability Systems,"

The NRC staff also evaluated the licensee’s discussion addressing the considerations in NRC

Regulatory Issue Summary (RIS) 2001-19, "Deficiencies in the Documentation of Design Basis Radiological Analyses Submitted in Conjunction with License Amendment Requests."

Except where the licensee proposed a suitable alternative, the staff utilized the regulatory guidance provided in the following documents:

- Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors"
- SRP Section 15.1.5, "Steam System Piping Failures Inside and Outside of Containment (PWR)," Appendix A
- SRP Section 15.3.3, "Reactor Coolant Pump Rotor Seizure"
- SRP Section 15.4.8, "Spectrum of Rod Ejection Accidents (PWR)," Appendix A
- SRP Section 15.6.2, "Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant Outside Containment"
- SRP Section 15.6.3, "Radiological Consequences of Steam Generator Tube Failure (PWR)"

The NRC staff also considered relevant information in the Callaway FSAR and TSs.

3.5.3 Technical Evaluation

The NRC staff reviewed the regulatory and technical analyses in the licensee's application, as related to the radiological consequences of DBAs. These DBA consequences were calculated by the licensee in support of its proposed license amendment. Information regarding these analyses was provided in Section 4.1 in Attachment 1 of the application. The NRC staff reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological consequences of the DBAs. The NRC staff's review of these consequences are based on the descriptions of the licensee’s analyses and other supporting information in the licensee's letters.

The licensee evaluated the impact of the replacement SGs and the proposed TS changes on the DBA dose consequences analyses for the Callaway Plant. As stated in its application, the licensee determined that there are no impacts to the LBLOCA dose analysis inputs or assumptions, as discussed in Callaway FSAR Section 15.6, from the replacement SGs. Therefore, the licensee did not calculate any revised doses, and the current licensing basis radiological consequences analysis for the LBLOCA remains bounding. Because the replacement SG dimensions and liquid/steam capacities are not relevant to the LOCA dose analysis inputs, nor are the proposed TS changes, the NRC staff agrees that the current LOCA radiological consequences analysis remains bounding for operation with the replacement SGs.

The licensee calculated the radiological consequences of the following DBAs and transients, which are affected by operation with the replacement SGs:

- MSLB accident

- Loss of non-emergency AC power to the station auxiliaries
- Locked rotor accident
- Rod ejection accident
- Chemical and volume control system letdown line break outside of containment
- SGTR accident

The licensee stated that it used current plant licensing basis assumptions for parameters such as the fuel and rod gap source term, atmospheric dispersion factors (χ/Qs), breathing rates, control room occupancy factors and ventilation system flow rates, and whole body and thyroid dose conversion factors. The licensee used revised analysis inputs and assumptions to model the replacement SGs, such as replacement SG initial liquid and steam mass, break flow rate and steam mass release. The licensee’s analysis of the replacement SG steam releases were reviewed by the NRC staff. The licensee also calculated both offsite and control room doses. The licensee stated that the replacement SGs have a minimal impact on the doses calculated for the re-analyzed accidents, where minimal is defined as an increase that is less than 10 percent of the margin between the regulatory limit and the current plant licensing basis dose. The licensee further stated that in all cases, the dose consequences calculated in support of the proposed license amendment are less than the applicable regulatory limits of 10 CFR Part 100 and GDC 19. Based on this, the NRC staff concludes that the licensee’s analysis has shown that the regulatory dose criteria in 10 CFR Part 100 and GDC 19 remain met for the replacement SG and the proposed supporting TS changes.

The licensee also evaluated the impact of the proposed TS changes and operation with replacement SGs on the control room habitability analyses. It did this by calculating revised doses for the above listed DBAs and addressing the considerations documented in RIS 2001-19. The NRC staff has evaluated the licensee's discussion on the appropriateness of the control room habitability analysis assumptions for DBAs other than a LOCA, as addressed by the licensee and documented in Section 4.1 of Attachment 1 to the September 17, 2004, application. For each re-analyzed DBA, the licensee evaluated the assumptions on control room isolation, capability of control room intake radiation monitors, control room receptor atmospheric dispersion factors, control room unfiltered in-leakage, and credit for use of personal respirators and potassium iodide (KI). Based on its review of the licensee's evaluation, the NRC staff finds that the licensee’s discussion indicates that appropriate care has been taken by the licensee in its analysis of the radiological consequences in the control room, from the replacement SGs, for DBAs other than LOCA. The revised radiological consequences analyses confirmed, and the NRC staff agrees, that the LBLOCA control room doses currently reported in Callaway’s FSAR remain bounding for the above re-analyzed DBAs, and the control room habitability dose criteria of GDC 19 continues to be met.

3.5.4 Conclusions

As described above, the NRC staff has reviewed the assumptions, inputs, and methods used by the licensee to assess the radiological impacts of the replacement SGs and the proposed supporting changes to the TSs at Callaway. Based on this review, the NRC staff concludes that the licensee has used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance on radiological dose consequences of DBAs that are identified in Section 3.5.2 of the SE. The NRC staff has compared the doses estimated by the licensee to the regulatory requirements and guidance and concludes, with reasonable assurance, that the licensee’s estimates of the offsite and control room doses will continue to

comply with these requirements and guidance. Based on this, the NRC staff further concludes that the revised DBA and control room dose consequences are acceptable and that operation with the replacement SGs and the proposed supporting TS changes, which are addressed in other sections of this SE, are acceptable with regard to the dose consequences of the postulated DBAs and control room habitability.

3.6 Containment Integrity Review

3.6.1 Introduction

In a letter dated September 17, 2004, the licensee requested a license amendment to revise the TSs to support installation of the replacement SGs. The licensee supplemented this application with information relevant to the containment aspects of this review in letters dated February 11 and June 17, 2005. The Callaway plant is currently equipped with Westinghouse Model F SGs and the licensee is proposing to replace these SGs with Framatome Model 73/19T SGs. In support of this change the licensee has provided technical analyses which include analyses of the containment response to DBAs in WCAP-16265-P.

The licensee is also requesting a revision to TS 5.5.16, "Containment Leakage Rate Testing Program," to add an exception to the Containment Leakage Rate Testing Program which will eliminate the requirement to perform an ILRT following installation of the replacement SGs. This proposed exception is addressed in Section 3.6.3.4 of this SE.

A previous license amendment proposed credit for the main feedwater (MFW) control (flow regulating) valves as a backup to a postulated single failure of a main feedwater isolation valve (MFIV). This proposed amendment was approved by the NRC in a letter dated May 31, 2005. The licensee is crediting this back-up feature in the revised design-basis analyses.

3.6.2 Regulatory Evaluation

3.6.2.1 LOCA Mass and Energy Release

The following regulations provide acceptance criteria for the LOCA mass and energy release inside containment:

- GDC 4, of Appendix A to 10 CFR Part 50, requires that structures, such as the walls of subcompartments inside containment, shall be appropriately protected from the dynamic effects associated with pipe ruptures.

- Paragraph I.A, “Sources of heat during the LOCA,” to Appendix K of 10 CFR Part 50 provides criteria for the heat sources considered in the LOCA mass and energy release analyses.

3.6.2.2 LOCA Containment Response

The following regulations provide acceptance criteria for the LOCA containment response:

- GDC 50, Containment design basis, requires that the containment, shall be designed to accommodate, without exceeding the design leakage rate and with sufficient margin, the

calculated conditions from any LOCA.

- Appendix K to 10 CFR Part 50 cites sources of energy that must be considered as part of a LOCA analysis.

3.6.2.3 MSLB Accident

For the MSLB accident, the following regulations are applicable:

- GDC 16 requires the containment to provide an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment following a design basis accident.

- GDC 38 requires a system to remove heat from the reactor containment and that this system rapidly reduce the containment pressure and temperature following a LOCA. Two diverse Callaway systems satisfy this requirement: the containment spray system and the containment fan cooler system.

3.6.3 Technical Evaluation

The pressure within the containment must remain below the containment's design pressure (60 psig for Callaway) following a postulated LOCA and MSLB.

In its application, the licensee discussed some of the conservatisms in the LOCA and MSLB analyses that were done to support the replacement SGs. Other conservatisms are discussed in WCAP-16265-P and in the licensee's February 11 and June 17, 2005, letter responses to NRC RAIs and given below:

> The containment volume, heat sink areas and thickness input values are taken from the previous licensing basis containment pressure/temperature analysis and are typically biased low to maximize the pressure for the containment DBA [design basis accident] evaluation model. The minimum free volume in the containment DBA evaluation model is calculated by subtracting the uncertainty in the measured free volume data. Likewise the heat sink input for the containment DBA evaluation model is calculated by subtracting the uncertainty in the measured heat sink area and/or thickness.

Based on its review of the information provided by the licensee, the NRC staff finds that the input assumptions for the LOCA and MSLB analyses are sufficiently conservative.

3.6.3.1 LOCA Containment Response

The LOCA containment response is divided into the short-term and long-term responses, as discussed below:

3.6.3.1.1 LOCA Short-Term Containment Response

The licensee evaluated the effect of the replacement SGs on the short-term LOCA containment response analysis, which is also termed the containment subcompartment analysis. A subcompartment is defined in SRP Section 6.2.1.2, "Subcompartment Analysis," as a fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. For these analyses, the licensee assumed a RCS pressure of 2300 psia and a vessel/core inlet temperature of 535.2 EF. The NRC staff concludes that this is a high value of pressure and a low value of temperature, and is, therefore, conservative for these calculations since these high and low values of pressure and temperature will tend to overestimate the mass released from the break.

The licensee stated that the mass and energy released into the subcompartment are calculated with the Westinghouse SATAN computer code using the Zaloudek critical mass flux correlation. Both SATAN and the Zaloudek correlation are acceptable methods and the NRC has approved many similar license amendment requests using these methods.

The licensee also stated that any changes in RCS or SG liquid/steam mass and volume have no effect on the mass and energy releases because of the short duration of the postulated accident. Any volumetric changes are small and have no impact on the subcompartment

model. Therefore, the licensee concluded that the only change that needs to be addressed is the decreased RCS temperatures. The NRC staff concurs with this conclusion.

The NRC staff has approved leak-before-break (LBB) for Callaway. RCS piping determined not to catastrophically rupture in accordance with LBB does not have to be considered by the licensee in its subcompartment analyses. The licensee stated in its application that it intended to apply LBB to the pressurizer surge line as part of its installation of the replacement SGs. The licensee stated that this would be necessary to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse accompanying a high-energy line break within the compartment containing the pressurizer surge line. The Callaway FSAR states that the design basis for the pressurizer compartment is the double ended pressurizer surge line break. However, in its letter dated July 15, 2005, the licensee stated that LBB is not required for the pressurizer surge line because the pressurizer vault analysis shows less pressurization than shown in FSAR Table 6.2.1-26 and, therefore, operation of Callaway at a Tavg as low as 570.7 $^{\circ}$F would not result in pressures exceeding the pressurizer vault loading criteria in the event of a double-ended break in the pressurizer surge line.

Based on the above discussion, the NRC staff concludes that compliance with GDC 4, with respect to subcompartment analysis, is maintained with the replacement SGs.

3.6.3.1.2 LOCA Long-Term Response

The licensee stated that the mass and energy discharged from the break inside containment are calculated using methods previously approved by the NRC (Reference 6.1). Using these results, the licensee calculated the long-term response of the Callaway containment to the LOCA. These calculations were performed with the GOTHIC containment code (Reference 6.2), which has been used previously in NRC-approved LOCA analyses. The licensee addressed the application of the GOTHIC code to the containment for the replacement SGs. As discussed in Section 3.6.3.3 of this SE, the NRC staff concludes that the application

of GOTHIC for these analyses is acceptable.

The Callaway containment design pressure is 60 psig. The licensee's calculated peak containment pressure is 46.25 psig as a result of a double-ended hot leg LOCA from full power. Since the LOCA peak pressure is less than the design value and has been calculated with acceptable methods using conservative assumptions, the NRC staff concludes that the Callaway long-term pressure containment LOCA response for the replacement SGs is acceptable.

3.6.3.2 MSLB Response

The licensee has determined that the limiting MSLB with respect to containment pressure is a split pipe break at zero power. The peak containment pressure calculated by the licensee is 44.8 psig, which is also less than the containment design pressure of 60 psig.

The licensee determined that the limiting MSLB, in terms of containment temperature, is a double-ended main steam line rupture from 102 percent RTP. The peak temperature calculated by the licensee for this case is 352.8 EF.

The licensee stated that the MSLB mass and energy calculations for the replacement SGs were done using Westinghouse methods which have been previously approved by the NRC. These are EPRI NP-1850-CCMA, "RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems," dated April 1984, and WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactors Non-LOCA Safety Analysis," dated April 1999 (References 3 and 4 in Section 6.6.1.7 of WCAP-16265-P). The licensee also stated that the GOTHIC computer code is used for the containment response to the MSLB.

As described by the licensee, in Section 6.6.1.2 of WCAP-16265-P, conservative input values have been assumed by the licensee for these analyses. It is necessary for the MSLB accident calculations to examine a range of powers and single failure assumptions. These are also described in Section 6.6.1.2 of WCAP-16265-P. Since a single failure is included in the mass and energy release calculations, no single failure is modeled in the containment response calculations. The NRC staff concludes that this is the typical procedure for this calculation and is, therefore, acceptable for Callaway.

One of the single failures considered in the MSLB accident analyses is the failure of a MFIV in the open position. In this case, feedwater isolation would be provided by closure of the MFW flow regulator valve. The licensee considered the additional inventory of water between these valves. The NRC approved this in Amendment No. 167, which was issued May 31, 2005.

Based on the above, the NRC staff concludes that the Callaway long-term pressure containment MSLB response for the replacement SGs is acceptable.

3.6.3.3 Application of GOTHIC to Callaway Containment Safety Analyses

The GOTHIC code is a general purpose thermal hydraulics computer program for the analysis of a nuclear power plant containment. GOTHIC was developed for the Electric Power Research Institute (EPRI) by Numerical Applications, Incorporated (NAI). NAI validated

GOTHIC by comparison with analytical solutions and experimental data. The NRC has previously approved containment analyses using the GOTHIC code. The licensee stated that it has used GOTHIC 7.1p1 for the containment analyses and these analyses are consistent with the conditions and limitations of a previous staff review of GOTHIC (Reference 6.3).

In the following statement, the licensee described the quality assurance program used for the application of the GOTHIC code to Callaway.

> The GOTHIC computer code for the Callaway RSG [replacement steam generator] Program was developed and implemented by Westinghouse in accordance with their Quality Assurance program. That invokes the requirements of 10 CFR 21 and 10 CFR 50 Appendix B. Westinghouse is currently listed on the AmerenUE Qualified Supplier List for Engineering Services.

Based on this quality control on the application of the GOTHIC code to Callaway, the NRC staff finds that the licensee’s use of GOTHIC in the Callaway containment analyses is acceptable.

3.6.3.4 Exception to Callaway Containment ILRT Program

The licensee has proposed to add the following exception to the requirement in TS 5.5.16 to perform an ILRT: "The unit is excepted from post-modification integrated leakage rate testing requirements associated with steam generator replacement during Refuel 14 outage (fall 2005)." The exception would allow the licensee to not perform an ILRT in Refuel 14 outage after the installation of the replacement SGs. The replacement SGs can be installed without the containment being cut.

During the LOCA, portions of the SGs and attached lines are relied on as a barrier against the uncontrolled release of radioactivity to the environment. The portions impacted, that are considered part of the containment boundary, are the outer shell of the SGs, the inside containment portions of lines emanating from the SG shells (i.e., the main steam lines, the MFW lines, the SG blowdown and sample lines) and the inside surface of the SG tubes.

TS 5.5.16.a requires (1) that a program be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions and (2) that the program must be performed in accordance with NRC Regulatory Guide 1.163 (Reference 6.4) which, in turn, endorses the Nuclear Energy Institute document NEI 94-01, Revision 0 (Reference 6.5). NEI 94-01, Revision 0, states that a Type A test (or ILRT) or local leak rate test (LLRT) be conducted prior to returning the containment to operation following a modification that affects containment integrity. Replacing the SGs is such a modification since, as discussed above, the replacement would affect portions of the containment boundary.

The licensee stated that performing the ILRT is unnecessary because the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (the ASME Code) Section III/XI pressure test requirements satisfy the intent of 10 CFR Part 50, Appendix J, Option B. The NRC staff reviewed the ASME Section XI requirements and determined that the ASME Section XI surface examination, volumetric examination, and system pressure testing requirements are more stringent than the ILRT requirements of Appendix J (which are currently

stated in TS 5.5.16). Although, the objective of the ILRT test is to ensure the leak tight integrity of the containment area affected by the modification, the ASME Section XI inspection and testing requirements more than fulfill the intent of the requirements of Appendix J and the provisions of NEI 94-01, Revision 0. In addition, the test pressure for the ASME Code system pressure test is significantly greater than that of the Appendix J test. Also, the replacement SGs can be installed at Callaway without the containment cut. Based on this, the NRC staff concludes that the licensee's proposed exception from performing a post-modification ILRT following the installation of the replacement SGs is acceptable. Based on this, the NRC staff further concludes that the containment will continue to meet GDC 50 without conducting the ILRT after the installation of the replacement SGs and, therefore, the proposed change to TS 5.5.16 is acceptable.

3.6.3.4 Environmental Qualification of Equipment

The licensee addressed the effect of the replacement SGs on the environmental qualification of equipment inside containment on pages 19 and 20, of 51, in Attachment 1 to its application. In that section on the containment pressure/temperature response associated with the SG replacement, the licensee stated that the new Callaway containment evaluation model was based on the NRC-approved model for Kewaunee using the GOTHIC code with most of the input data taken from the CONTEMPT LOCA and MSLB input decks. The GOTHIC model was used to produce sample results for the LOCA and MSLB transients using conservative mass and energy release data that is representative of the Callaway plant. The containment temperature for the LOCA and MSLB remained less than 270 °F and 352.8 °F, respectively, which are less than the peak temperature listed in the Callaway FSAR Tables 6.2.1-8 and 6.2.1-58, respectively. Because the peak temperatures calculated for the replacement SGs are less than the current peak temperatures for the LOCA and MSLB in the FSAR, the licensee concluded that there will be no adverse impact on the environmental qualification of equipment inside containment.

The licensee stated that it used NRC-approved methodology to determine the peak containment temperature for the LOCA and MSLB, used conservative containment conditions and the replacement SG parameters, and calculated peak temperatures that are less than the current peak temperature in the Callaway FSAR. Based on this, the NRC staff concludes that the environmental qualification of equipment inside containment is bounded by the current environmental qualification of such equipment in the FSAR and, therefore, the plant continues to meet 10 CFR 50.49, "Environmental qualification of electric equipment important to safety for nuclear power plants."

3.6.3.5 Conclusions

In its application, the licensee addressed containment integrity for the installation of the replacement SGs and proposed a change to TS 5.5.16 to allow the plant restart after the installation without performing an ILRT. As discussed above, the NRC staff concludes that the licensee has demonstrated that containment integrity remains acceptable for plant operation and that the proposed change to TS 5.5.16 is acceptable.

3.7 RCS Loop Piping and Supports, and Pressurizer

The licensee assessed the effect of the replacement SGs on the RCS loop piping and supports,

and the pressurizer. The SGs are connected to the RCS in that they provide the heat sink for the RCS coolant and the RCS includes the pressurizer. The licensee addressed the effects of the replacement SGs on these components in Section 5.5 of WCAP-16265-P.

For the RCS loop piping and supports, the licensee stated that, with the new replacement SGs, the structural design of the SGs has changed by a significant enough amount that a re-analysis of the RCS loop piping and support system was required and this re-analysis was performed to qualify the loop piping and primary equipment supports, and to re-demonstrate leak before break (LBB) for the piping. The re-analysis activities conducted by the licensee with respect to the Callaway loop piping and support system are addressed in Section 5.5 of WCAP-16265. The conclusion of the re-analysis is that the deadweight, thermal time-history seismic operating basis and safe shutdown earthquakes, LOCA, main steam system line, and MFW line break analyses were performed for Callaway for the installed replacement SGs and the results are the following:

- An RCS loop piping stress analysis was performed for all load condition combinations and higher stressed locations. A re-analysis for thermal, seismic, and LOCA conditions was performed to show the design-basis requirements continued to be met;

- Primary equipment nozzle loads were determined to qualify all the primary equipment nozzles;

- Equipment support loads and displacements were reviewed for all primary components supports to demonstrate compliance with the design-basis allowable limits;

- Piping analyses of all Class 1 auxiliary lines attached to the RCS loops were completed to include the thermal, seismic, and LOCA, main steam, and feedwater pipe break, and fatigue effects from the replacement SGs;

- The main steam and feedwater piping systems were re-qualified with the replacement SGs for the current thermal, seismic, and LOCA analyses;

- The deadweight, thermal, time-history seismic operating basis earthquake(OBE) and safe shutdown earthquake (SSE), MSLB and main feedwater line break analyses were performed for the replacement SGs; and

- Re-demonstration of LBB for all applications where the NRC approved LBB for the accumulator and RHR lines in Amendment No. 161 issued April 12, 2004, and for the primary coolant loops in the NRC letter issued October 28, 1986.

The licensee stated in its application that it would seek to apply LBB for the pressurizer surge line which had not been approved in Amendment No. 161 issued April 12, 2004. However, in its supplemental letter dated July 15, 2005, the licensee stated that LBB for the pressurizer surge line is not needed. The licensee explained that pressurizer vault analysis shows there is less pressurization than shown in FSAR Table 6.2.1-26 and, therefore, operation of Callaway at a Tavg as low as 570.7 ^{o}F would not result in exceeding the pressurizer vault loading criteria in the event of a double-ended break in the pressurizer surge line. Because the mechanical design limitations of the steam dump system will limit the low end of the permissible Tavg range

to 573 °F, the pressurizer skirt pressurization analysis was re-analyzed to verify the uplift forces on the pressurizer. The licensee stated that the newly calculated uplift load on the pressurizer can be accommodated by the pressurizer supports and, therefore, LBB for the pressurizer surge line is not needed.

The licensee stated that the results of these analyses are the following:

- The new stresses in the RCS loop piping are less than the allowable stresses;

- The RCS piping secondary stresses and fatigue usage factors are in conformance with the requirements of the ASME Code for the fatigue damage evaluation performed under all normal, upset, and test conditions and, therefore, the piping system is adequate for all design transient conditions described in the design specification, which is Reference 3 in Section 5.5.1.7 of WCAP-16265;

- The Class 1 RCS loop branch nozzle stresses and usage factors are within the allowable limits and, therefore, they will maintain their structural integrity;

- The new RCP, reactor vessel, and replacement SG primary-side equipment nozzle loads are less than the allowable nozzle loads;

- Stresses in all support members of the reactor vessel, RCPs, and SGs are within the allowable values for normal, upset, and faulted conditions;

- Stresses in auxiliary, main steam, and main feedwater line piping and supports remain within the ASME Code allowables and, therefore, are acceptable; and

- LBB for the RCS loop piping, accumulator line, and RHR line was demonstrated, as clarified above for the pressurizer surge line.

For the pressurizer, the licensee stated that an analysis was done to address the impact on the pressurizer. The input parameters associated with the replacement SGs were reviewed and compared to the current input parameters for the pressurizer. In cases where the replacement SG parameters were not bounded by the current parameters, pressurizer structural analyses and evaluations were performed and the results were compared with the ASME Code to confirm the allowable limits were maintained. All critical components of the pressurizer were evaluated for operation with the replacement SGs. The licensee reported that all ASME Code stress limits remained satisfied for all components for all operating conditions.

The licensee concluded in its application that the re-analyses for the NSSS components, which includes the RCS loop piping and supports, and pressurizer, confirmed that, with the replacement SGs, these components continued to satisfy the applicable codes and standards.

Based on its review of the licensee's application, the re-analyses done for the RCS loop piping and supports, and pressurizer, and the results of the re-analyses stated above, the NRC staff concludes that the NSSS components continue to meet the applicable codes and standards and the replacement SGs are acceptable.

3.8 Balance of Plant Considerations

The licensee stated that it reviewed the following Callaway SSCs to determine if any of them were affected by the replacement SG activities:

- Main Steamline Differential Pressure
- Containment Cooling and Heating, Ventilation, and Air Conditioning (HVAC)
- Containment Spray System
- Sump pH
- Time to Boil
- RCS Natural Circulation
- Essential Service Water
- Secondary Chemical Addition System
- Secondary Sample System
- SG Blowdown System
- High Energy Line Breaks
- Replacement SG Radiological Consequences (separate from Section 3.5 of this SE)

The licensee stated that the above areas, as well as other plant calculations and documents, were evaluated for replacement SG conditions and the effect of installing the replacement SGs. It stated that any changes needed to support systems can be done without a change to the TSs (i.e., beyond what the licensee has submitted) and without prior NRC review and approval. The NRC staff has no disagreement with this because 10 CFR 50.59 allows changes to the facility as described in the FSAR without prior NRC approval if the changes meet the criteria in the regulation. Also, the licensee annually reports the changes to its facility that met the criteria in 10 CFR 50.59 and, thus, were made without prior NRC staff review and approval and, within the NRC ROP, there may be inspections of the licensee's 10 CFR 50.59 process to determine if the licensee is properly doing such evaluations. Therefore, the NRC staff concludes that the licensee's consideration of the balance of plant with respect to the replacement SGs is acceptable.

3.9 Conclusions

The NRC staff has reviewed the licensee's proposed installation of the replacement SGs with respect to the following areas of review: (1) I&C, (2) SG tube integrity, (3) plant systems, (4) reactor systems, (5) dose consequences for DBAs, (6) containment integrity, (7) RCS loop piping and supports, and pressurizer, and (8) balance of plant considerations. These areas were addressed in Section 3.1 through 3.8, respectively, of this SE. Based on its conclusions in these sections, the NRC staff concludes that the installation of the replacement SGs will not cause the plant to operate in an unsafe condition and meets the applicable GDC of Appendix A to 10 CFR Part 50. Because of this, the NRC staff further concludes that the installation of the replacement SGs is, therefore, are acceptable. Based on this conclusion and the NRC staff's conclusions on the proposed TS changes in the following subsections of the SE:

- Subsection 3.1.3.2 and 3.1.3.3, "Instrumentation and Controls (I&C) Review," addresses the changes to TSs 3.3.1 and 3.3.2;
- Subsection 3.2.3.5.4, "Definition of Leakage," addresses the change to the definition of leakage;
- Subsection 3.2.3, "SG Tube Integrity Review," addresses the changes to the Table of Contents and TSs 3.4.13, 3.4.17, 5.5.9, and 5.6.10;.
- Subsection 3.3.3.2, "Plant Systems Review," addresses the changes to TS 3.7.1;

- Subsection 3.4.3.11, "Reactor Systems Review," addresses the changes to TSs 2.1.1, 3.4.1, 3.4.5, 3.4.6, and 3.4.7; and
- Subsection 3.6.3.4, "Containment Integrity Review," which addresses the changes to TS 5.5.16;

the NRC staff also concludes that the proposed amendment to the TSs meets 10 CFR 50.36 and, therefore, is acceptable.

In its application and supplemental letters for this amendment, the licensee has also identified the changes to the TS Bases that are associated with the proposed TS changes listed above. The NRC staff has discussed these changes to the TS Bases. Based on its review, the NRC staff does not disagree with any of these identified changes to the TS Bases.

The licensee stated in its application that the amendment would be implemented prior to entry into Mode 5 in the restart of Callaway from Refueling Outage 14 in which the licensee will remove the original SGs and install the replacement SGs. Because the amendment will be implemented prior to when the replacement SGs are required to be operable, the NRC staff concludes that this implementation period is acceptable.

In the amendment, there will be the following condition on the operating license: This amendment is effective as of its date of issuance, and shall be implemented before entry into Mode 5 during the restart from the fall 2005 refueling outage when the replacement steam generators are installed, and shall include the following: (1) revision of the PTLR to change the COMS setpoints to reflect no reactor coolant pump operation restrictions and (2) incorporation of the TS Bases changes identified in the licensee's letter of September 6, 2005, into the TS Bases. Items (1) and (2) are addressed in Sections 3.1.3.2 and 3.4.3.5 of this SE. These actions can not be done until the NRC has approved the amendment, but they are being relied upon by the NRC staff in approving the amendment. Therefore, these actions will be required to be performed as a condition on the operating license. In the case of item (2), the licensee could decide that it wanted to revise what it identified as changes to TS Bases in its September 6, 2005, letter. The TS Bases Control program in TS 5.5.14 controls such changes in that the licensee may make changes to the TS Bases without prior NRC approval if the changes do not require a change to TSs or a change to updated FSAR or TS Bases pursuant to 10 CFR 50.59. Changes to the TS Bases that are done in accordance with the criteria specified in TS 5.5.14 are acceptable to the NRC staff. The licensee has agreed to these conditions.

4.0 REGULATORY COMMITMENTS

The licensee submitted the following regulatory commitments in Attachment 5 to its application:

1. The licensee will adopt the NRC-approved revision of TSTF -449 by submitting a license amendment request within 60 days of NRC approval of the final revision of the TSTF.

2. The licensee will provide documentation regarding effective mitigation measures to be applied at the Alloy 82/182 pressurizer safe end weld by November 30, 2004.

3. The licensee will submit an amendment request to revise TS 3.7.3 to be consistent with revision 3 of the Improved Standard TSs in NUREG-1431 that adds the main feedwater control and bypass valves to LCO 3.7.3 by November 30, 2004.

4. The licensee will implement the proposed TS changes for this amendment prior to entry into Mode 5 in the restart of the plant from Refueling Outage 14.

5. The licensee will submit an amendment request to revise TS 3.7.2 if it decides to install MSIV actuators during Refueling Outage 14 by November 30, 2004.

For No. 1 above, by its letter dated June 17, 2005, the licensee submitted TS changes to conform to the NRC-approved TSTF-449, Revision 4.

For No. 2 above, because the license did not submit an application to apply LBB for the pressurizer surge line, which is addressed in the licensee's letter dated July 15, 2005, it did provide any documentation regarding effective mitigation measures to be applied at the Alloy 82/182 pressurizer safe end weld. See the discussion in Section 3.4.3.8.1 of this SE.

For No. 3 above, the licensee submitted its application for the amendment in its letter dated October 27, 2004, and the NRC staff issued the amendment (Amendment No. 167) on May 31, 2005.

For No. 4 above, a license condition states that the amendment is effective as of its date of issuance, and shall be implemented before entry into Mode 5 during the restart from the fall 2005 refueling outage when the replacement steam generators are installed.

For No. 5 above, the licensee decided not to install the MSIV actuators in the upcoming Refueling Outage 14 and, therefore, did not submit the amendment request.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Missouri State official was notified of the proposed issuance of the amendment. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes requirements with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (69 FR 68185). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there

is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

8.0 REFERENCES

For Section 3.2 of this SE:

2.1 Letter, R.E. Beedle, NEI, to L. J. Callan, NRC, December 16, 1997, which transmitted NEI 97-06 (Original), “Steam Generator Program Guidelines.”

2.2 NEI 97-06, Revision 1, “Steam Generator Program Guidelines,” January 2001. ADAMS Accession No. ML010430054.

2.3 SECY-00-0078, “Status and Plans for Revising the Steam Generator Tube Integrity Regulatory Framework,” March 30, 2000.

2.4 Letter, Sean Peters, NRC, to L. M. Stinson, Vice President, Southern Nuclear Operating Company, “Joseph M. Farley Nuclear Plant, Units 1 and 2, re: Issuance of Amendments to Facilitate Implementation of Industry Initiative NEI 97-06, Steam Generator Program Guidelines,” dated September 10, 2004. (ADAMS Accession No. ML042570427).

2.5 Draft Regulatory Guide 1.121, “Bases for Plugging Degraded PWR Steam Generator tubes,” August 1976.

2.6 Memorandum dated September 8, 1999, to W. H. Bateman, Chief, EMCB, NRR, NRC from J. W. Anderson, EMCB, NRR, NRC, “Summary of August 27, 1999, Senior Management Meeting with NEI/EPRI/Industry to Discuss Issues Involving Implementation of NEI 97-06.” This memorandum encloses Industry White Paper entitled, “Deterministic Structural Performance Criterion Pressure Loading Definition.”

2.7 Memorandum dated May 19, 2004, from J. L. Birmingham, Project Manager, NRR, NRC to Cathy Haney, Program Director, Policy and Rulemaking Program, Division of Regulatory Improvement Programs, NRR, NRC, “Summary of May 14, 2004 Meeting with Nuclear Energy Institute (NEI) on Status of Steam Generator Structural Integrity Performance Criteria.” ADAMS Accession No. ML041540500.

2.8 NUREG-1570, “Risk Assessment of Severe Accident -Induced Steam Generator Tube Rupture,” March 1998.

2.9 NUREG-1022, Rev 2, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” October 31, 2000.

2.10 NUREG-1649, Rev 3, “Reactor Oversight Process,” July 2000.

For Section 3.4 of this SE:

4.1 NUREG-0800, “Standard Review Plan,” Draft Revision, April 1996.

4.2 ASME Boiler and Pressure Vessel Code, Section III, Nuclear Power Plant Components, 1974, with Addenda Summer 1974, Division I, Subsection NA and NB, and Appendices.

4.3 WCAP-10266-P-A, Revision 2, “The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code,” March 1987.

4.4 Thompson, C.M. et al., “Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model,” WCAP-10054-P-A, July,1997.

4.5 WCAP-10266-P, Revision 2, Addendum 3, “Incorporation of the LOCKBART Transient Extension Method into the 1981 Westinghouse Large Break LOCA Evaluation Model with BASH (EM),” December 2002.

4.6 WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al, April 1999.

4.7 WCAP-14565-A (Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X., et al., October 30, 1999.

4.8 WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, Y.S. Liu et al., September 1986.

4.9 WCAP-11397-P-A, Revised Thermal Design Procedure, A.J. Friedland and S. Ray, April 1989.

4.10 Letter from Alan Passwater, Union Electric Company, Callaway Plant, to NRC, “Revision Technical Specifications 3.3.2, 3.4.10, and 3.4.11, Pressurizer Safety Valves and Relief Valves,” ULNRC-04258, dated May 25, 2000

4.11 Letter from Jack Donohew, USNRC, to Garry Randolph, Union Electric Company, Callaway Plant, “Issuance of Amendment Re: Pressurizer Safety Valves and Power-Operated Relief Valves,“ dated September 25, 2000.

4.12 Westinghouse Letter NS-TMA-2182, “Anticipated Transients Without Scram for Westinghouse Plants,” December 1979.

4.13 NRC Staff Report NUREG-0460, Volume 3, “Anticipated Transients Without Scram for Light Water Reactors,” December 1978.

4.14 ANS 51.1, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants (replaces ANSI N18.2), 1983

4.15 Letter from Jack Donohew, USNRC, to Garry Randolph, Union Electric Company, Callaway Plant, “Issuance of Amendment Re: Main Feedwater/Auxiliary Feedwater Modification and Steam Generator Tube Rupture Re-Analysis,“ dated March 11, 2004.

4.16 ANSI/ANS-5.1-1979, "Decay Heat Power in Light Water Reactors," August 29, 1979.

4.17 Letter from Keith Young, Union Electric Company, Callaway Plant, to NRC, "Request for Additional Information regarding Technical Specifications Revisions Associated with the Steam Generator Replacement Project," ULNRC-05188, dated August 16, 2005.

4.18 NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," dated August 1991.

<u>Section 3.6 of this SE</u>:

6.1 Westinghouse LOCA Mass and Energy Release Model for Containment Design, WCAP-10325-P-A, May 1983 (Proprietary), WCAP 10326-A (Non-Proprietary) March 1979.

6.2 GOTHIC Containment Analysis Package, Version 7.0, Electric Power Research Institute.

6.3 Issuance of Kewaunee Nuclear Power Plant License Amendment No. 169, September 29, 2003.

6.4 NRC Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," September 1995.

6.5 "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J," NEI 94-01 Revision 0, Nuclear Energy Institute, July 21, 1995.

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