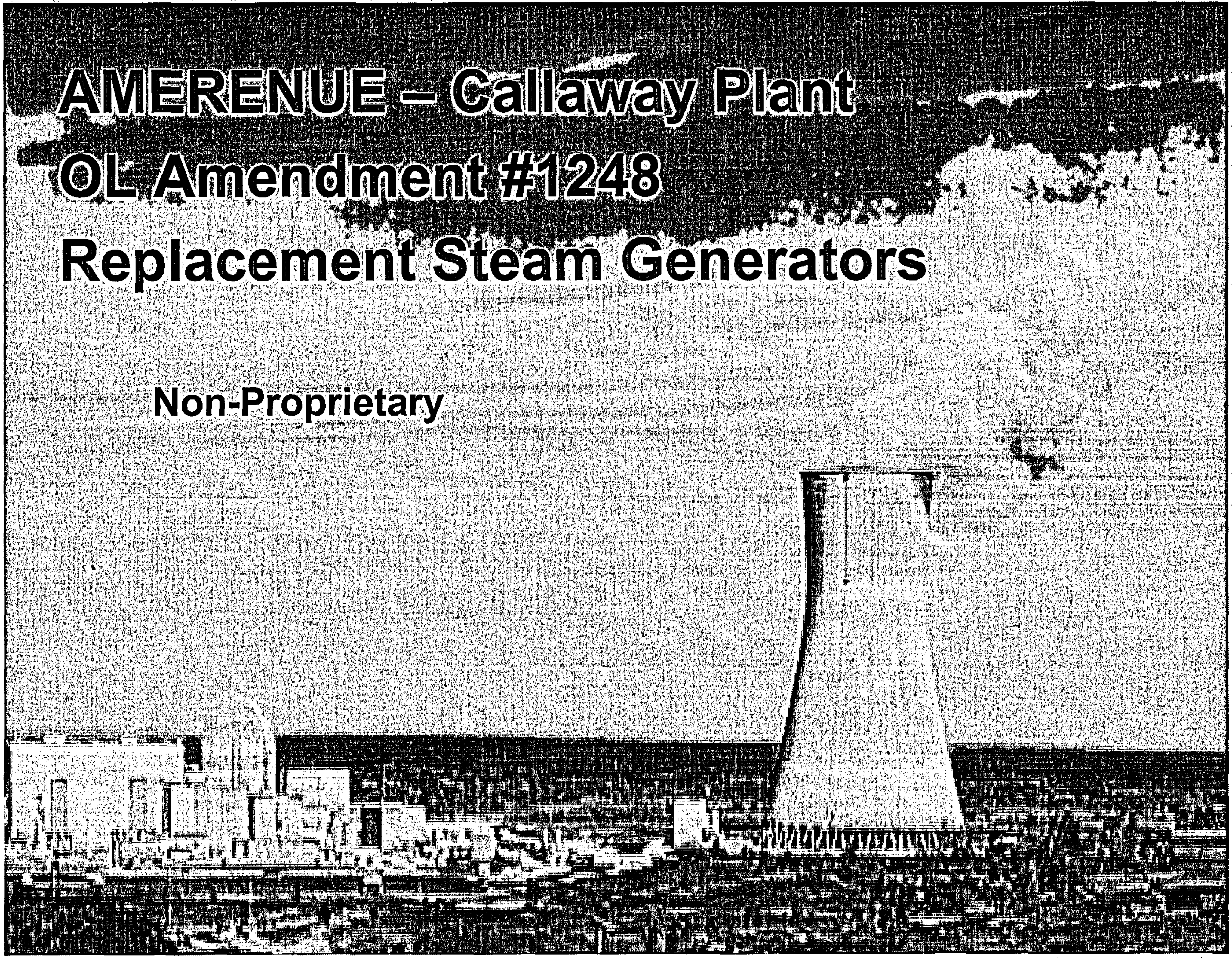
AMERENUE – Callaway Plant
OL Amendment #1248
Replacement Steam Generators
Non-Proprietary

EVALUATION

EVALUATION

1.0 DESCRIPTION

The proposed amendment would revise the following Technical Specifications (TS) in support of replacement steam generators to be installed during Refuel 14 (fall 2005):

- 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 Flow 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) Tube Surveillance Program";
- TS 5.5.16, "Containment Leakage Rate Testing Program"; and
- TS 5.6.10, "Steam Generator Tube Inspection Report."

In addition, the proposed amendment would add new TS 3.4.17, "Steam Generator Tube Integrity," pursuant to Reference 7.1, Technical Specification Task Force (TSTF) Improved Standard Technical Specifications Change Traveler TSTF-449 Revision 2. Section 7.0 of this Evaluation provides a listing of references cited herein.

2.0 PROPOSED CHANGES

The following changes to the TS are included in this amendment application:

1. Figure 2.1.1-1, "Reactor Core Safety Limits," will be replaced with a new figure to reflect the replacement steam generators and associated safety analyses.

2. 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 Trip Time Delay (TTD) portion of the Steam Generator (SG) Water Level Low-Low trip function will be deleted during Refuel 14, including the Vessel ΔT Equivalent (Power-1, Power-2) channels and the delay timers.

3. 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 % of loop minimum measured flow to % of indicated loop flow. This change was recommended by Westinghouse in response to item 10 of NSAL-00-008 regarding asymmetric RCS loop flows. Minimum measured flow is not cited in the Standard Technical Specifications (NUREG-1431). Consistent with this change, at the beginning of each cycle we will normalize the RCS flow transmitters during steady state, normal operating pressure, normal operating temperature (NOP/NOT) conditions such that they indicate at 100% flow in each respective loop, then verify the loop flow indications at an intermediate plateau and again at 100% rated thermal power. 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% of span, which is based on the indicated flow input from the flow transmitters. Deletion of Note (m) also eliminates the inconsistency in RCS flow limits listed in Note (m), which reflects a total RCS flow of 382,640 gpm (i.e., 95,660 gpm / loop x 4 loops), and the RCS flow limit listed in LCO 3.4.1, item c (382,630 gpm). The RCS flow limit used in the RSG analyses is correctly reflected in LCO 3.4.1, item c.

4. T' and T" in TS Table 3.3.1-1 are redefined to read the same. Both of these terms are used in the Overtemperature ΔT and Overpower ΔT trip functions in a similar fashion, to develop a variable reactor trip setpoint dependent upon the measured RCS average temperature, T. Both T' and T" refer to the nominal RCS average temperature at full power conditions (100% of rated thermal power, RTP). There is no basis for these terms to be defined differently for these trip functions. Based on the analyses performed by Westinghouse for the replacement steam generators, the nominal full power RCS average temperature will be maintained less than or equal to 585.3°F. Therefore, both T' and T" will be redefined as "the nominal T_{avg} at RTP, $\leq$ 585.3°F."

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

6. The Allowable Values for the following trip functions are decreased from $\geq$ 25.2% of Narrow Range Instrument Span to $\geq$ 20.6% of Narrow Range Instrument Span to reflect the replacement steam generators and associated setpoint calculations:

   a. TS Table 3.3.1-1, RTS Function 14.a, SG Water Level Low-Low (Adverse Containment Environment);

b. TS Table 3.3.2-1, ESFAS Function 5.e.(1), SG Water Level Low-Low (Adverse Containment Environment); and

c. TS Table 3.3.2-1, ESFAS Function 6.d.(1), SG Water Level Low-Low (Adverse Containment Environment).

7. The Allowable Values for the following trip functions are decreased from ≥ 19.8% of Narrow Range Instrument Span to ≥ 16.6% of Narrow Range Instrument Span to reflect the replacement steam generators and associated setpoint calculations:

a. TS Table 3.3.1-1, RTS Function 14.b, SG Water Level Low-Low (Normal Containment Environment);

b. TS Table 3.3.2-1, ESFAS Function 5.e.(2), SG Water Level Low-Low (Normal Containment Environment); and

c. TS Table 3.3.2-1, ESFAS Function 6.d.(2), SG Water Level Low-Low (Normal Containment Environment).

8. The Allowable Value for Safety Injection on Steam Line Pressure - Low (ESFAS Function 1.e in TS Table 3.3.2-1) will be increased from ≥ 571 psig (with the "c" footnote) to ≥ 609 psig (with the "c" footnote) to reflect the replacement steam generators and associated setpoint calculations.

9. The Allowable Value for Steamline Isolation on Steam Line Pressure - Low (ESFAS Function 4.e.(1) in TS Table 3.3.2-1) will be increased from ≥ 571 psig (with the "c" footnote) to ≥ 609 psig (with the "c" footnote) to reflect the replacement steam generators and associated setpoint calculations.

10. The Allowable Value for Turbine Trip and Feedwater Isolation on SG Water Level High-High (ESFAS Function 5.c in TS Table 3.3.2-1) will be increased from ≤ 79.8% of Narrow Range Instrument Span to ≤ 91.4% of Narrow Range Instrument Span to reflect the replacement steam generators and associated setpoint calculations.

11. The pressurizer pressure limit and RCS average temperature limit in TS 3.4.1, "RCS Pressure, Temperature, and Flow DNB Limits," are changed from ≥ 2220 psig to ≥ 2223 psig and from ≤ 592.6°F to ≤ 590.1°F, respectively. These changes reflect the revised safety analysis limits for the replacement steam generators while maintaining allowances for measurement uncertainty for instrument loop indications that are unaffected by the proposed changes.

12. Water levels used in the following LCOs will be revised to reflect the replacement steam generators and the associated indication instrument readings corresponding to the top of the SG tubes:

    a. SR 3.4.5.2 in TS 3.4.5, "RCS Loops - MODE 3," will be changed from a SG secondary side narrow range water level reading of $\geq 4\%$ to $\geq 7\%$.

    b. SR 3.4.6.2 in TS 3.4.6, "RCS Loops - MODE 4," will be changed from a SG secondary side narrow range water level reading of $\geq 4\%$ to $\geq 7\%$.

    c. LCO 3.4.7.b and SR 3.4.7.2 in TS 3.4.7, "RCS Loops - MODE 5, Loops Filled," will be changed from a SG secondary side wide range water level reading of $\geq 66\%$ to $\geq 86\%$.

13. TS 3.4.13, "RCS Operational Leakage," is revised to reflect Revision 2 of TSTF-449.

14. New TS 3.4.17, "SG Tube Integrity," is added to reflect Revision 2 of TSTF-449.

15. Table 3.7.1-1 of TS 3.7.1, "Main Steam Safety Valves (MSSVs)," is revised to decrease the Maximum Allowable Power for 3 OPERABLE MSSVs per SG from $\leq 49\%$ of Rated Thermal Power (RTP) to $\leq 45\%$ of RTP to reflect the replacement steam generators and associated safety analyses. A revised Loss of Load / Turbine Trip analysis covering operation with inoperable MSSVs was performed by Westinghouse for the RSG project. From the results of that analysis it was determined that operation with 3 OPERABLE MSSVs per steam generator could not be supported above 45% RTP.

16. TS 5.5.9, "Steam Generator (SG) Tube Surveillance Program," is retitled to "Steam Generator (SG) Program" and revised to reflect Revision 2 of TSTF-449.

17. TS 5.5.16, "Containment Leakage Rate Testing Program," is revised to take exception to the requirement to perform an integrated leak rate test after installation of the replacement steam generators.

18. TS 5.6.10, "Steam Generator Tube Inspection Report," is revised to reflect Revision 2 of TSTF-449.

Attachments 2 and 3 provide the TS markups reflecting the above changes and the retyped TS. Attachment 4 provides an information-only copy of the associated TS Bases changes, including the revised nominal trip setpoints associated with changes 6, 7, and 10 above in mark-ups to TS Bases Tables B 3.3.1-1 and B 3.3.2-1.

3.0 BACKGROUND

3.1 Nuclear Steam Supply System Evaluations for Replacement Steam Generators

The Callaway plant currently has Westinghouse Model F steam generators (referred to sometimes as the old steam generators or OSGs) installed. Framatome-designed Model 73/19T replacement steam generators (RSGs) will be installed prior to Cycle 15 operation (Fall 2005). A comparison of some of the RSG design features versus the currently installed steam generators is provided in the table below.

RSG VS. OSG COMPARISON

	Framatome 73/19T RSG	Model F
Tube Material	Alloy 690TT	Alloy 600MA
Tube OD (in)	3/4	11/16
Tube Wall Thickness (in)	0.043	0.040
Tube Pitch (in)	1.031 triangular	0.98 square
Number of Tubes	5872	5626
Tube Surface Area (ft^2)	78,946	55,000
Bundle Height (in)	433.9	348
TSP Type	Broached	Broached
Weight, Dry (lbs.)	743,100	715,000
Circulation Ratio	4.0	3.64
Best Est. RCS Flow (gpm)	104,438	101,900
Steam Press (psia) @ T-hot of 614°F (0% SG tube plugging)	1021	970
Specified MCO (%)	<0.10	<0.25

In support of this design change and associated license amendment, Westinghouse has performed analytical work to address the Nuclear Steam Supply System (NSSS) areas that are affected. The results and conclusions of the analyses that support the RSG project are included in the NSSS Licensing Report (attached as Appendix A to this amendment application), covering the following changes (items 1, 3, 4, 6 through 11, and 15 in Section 2.0 above):

- Reactor Core Safety Limits (new figure)
- Change in the manner in which the Reactor Coolant Flow - Low Allowable Value is defined, yet retaining the same numerical value
- Steam Generator Water Level Low-Low Allowable Values (new values)
- Change in the manner in which RCS average temperature is defined in the Overtemperature ΔT and Overpower ΔT setpoint equations, and a reduced upper limit for nominal T-avg at full power conditions (new value)
- Steam Line Pressure Low Allowable Values (new values)
- Steam Generator Water Level High-High Allowable Value (new value)
- Changes to the pressurizer pressure and RCS average temperature limits in the DNB LCO (new values)
- Main Steam Safety Valve Maximum Allowable Power vs. Number of Operable Valves (new value).

3.1.1 Water Level Indication Corresponding to the Top of the RSG Tubes

The physical changes corresponding to the RSG instrument tap locations and RSG internal design, combined with instrument loop indication accuracy considerations, require the inclusion of change 12 in Section 2.0 above. Since the same physical state is conveyed, i.e., that the top of the RSG tubes is covered, this change is considered to be a straightforward change requiring no further discussion or evaluation in Section 5.0 below.

3.1.2 Reactor Coolant Flow and RCS T-avg Changes

The basis for deleting Note (m) and re-defining the Reactor Coolant Flow - Low Allowable Value units in TS Table 3.3.1-1 is discussed in Section 2.0 (item 3) above. The changes in the values for T-avg in TS Table 3.3.1-1 for the Overtemperature ΔT and Overpower ΔT setpoint equations and the revised limits in LCO 3.4.1 on RCS average temperature and pressurizer pressure are all in the conservative direction. These changes drive the plant to an operating regime of lower temperature and higher pressure, further from DNB when compared to the existing limits.

3.2 TTD Elimination

Design features have been implemented into the replacement steam generators that reduce water level instabilities and inadvertent plant trips at low power levels with low steam generator water levels. Therefore, AmerenUE also requests that the trip time delay (TTD) portion of the SG Water Level Low-Low trip functions be eliminated. As discussed in WCAP-11325-P-A, Revision 1 (Reference 7.4), the trip time delay was a result of the Westinghouse Owners Group (WOG) Trip Reduction and Assessment Program (TRAP). The trip time delay can reduce inadvertent plant trips related to low steam generator level signals by adding a time delay to the steam generator low-low water level initiated reactor trip and auxiliary feedwater actuation. Through the use of adjustable timers in the protection system logic, the trip time delay allows added time for natural steam generator level stabilization or operator intervention to avoid an undesirable inadvertent protection system actuation. Implementation of the trip time delay as well as a functional description, calculations for the safety analysis limits, LOCA analysis and non-LOCA analysis were presented in WCAP-11833 which was reviewed and approved by NRC in Callaway License Amendment 43 dated April 14, 1989 (Reference 7.5). The steam generator water level low-low trip function currently allows a lower trip setpoint under normal containment environmental conditions and a delayed trip when thermal power is less than or equal to 22.41% Rated Thermal Power (RTP). Upon NRC approval, the 7300 Process Protection System will be modified to eliminate the TTD circuitry. The Environmental Allowance Modifier (EAM) portion of the SG Water Level Low-Low trip functions will remain unchanged after the TTD circuitry is eliminated. This change supports the elimination of the TTD portion of the SG Water Level Low-Low trip functions in changes 2 and 5 described in Section 2.0 above.

3.3 TSTF-449 Generic Licensing Change Package

The SG tubes in pressurized water reactors have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied upon to maintain the primary system's pressure and inventory. As part of the RCPB, the SG tubes are unique in that they act as a heat transfer surface between the primary and secondary systems to remove heat from the primary system. In addition, the SG tubes also isolate the radioactive fission products in the primary coolant from the secondary system.

Steam generator tube integrity is necessary in order to satisfy the tubing's safety functions. Maintaining tube integrity ensures that the tubes are capable of performing their intended safety functions consistent with the plant licensing basis, including applicable regulatory requirements.

Concerns relating to the integrity of the tubing stem from the fact that the SG tubing is subject to a variety of degradation mechanisms. Steam generator tubes have experienced tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. When the degradation of the tube wall reaches a prescribed repair criterion, the tube is considered defective and corrective action is taken.

The criteria governing structural integrity of SG tubes were developed in the 1970s and assumed uniform tube wall thinning. This led to the establishment of a through wall SG tube repair criteria (e.g. 40 percent) that has historically been incorporated into most pressurized water reactor (PWR) Technical Specifications and has been applied, in the absence of other repair criteria, to all forms of SG tube degradation where sizing techniques are available. Since the basis of the through wall depth criterion was 360°

wastage, it is generally considered to be conservative for other mechanisms of SG tube degradation. The repair criterion does not allow licensees the flexibility to manage different types of SG tube degradation. Licensees must either use the through wall criterion for all forms of degradation or obtain approval for use of more appropriate repair criteria that consider the structural integrity implications of the given mechanism.

For the last several years, the industry, through the Electric Power Research Institute (EPRI) Steam Generator Management Program (SGMP), has developed a generic approach to improving SG performance referred to as "Steam Generator Degradation Specific Management" (SGDSM). Under this approach, different methods of inspection and different repair criteria may be developed for different types of degradation. A degradation specific approach to managing SG tube integrity has several important benefits. These include:

- improved scope and methods for SG inspection;
- industry incentive to continue to improve inspection methods; and
- development of plugging and repair criteria based on appropriate NDE parameters.

As a result, the assurance of SG tube integrity is improved and unnecessary conservatism is eliminated. Over the course of this effort, the SGMP has developed a series of EPRI guidelines that define the elements of a successful SG Program. These guidelines include:

- TR-107569, "Steam Generator Examination Guideline" (Reference 7.6),
- TR-107621, "Steam Generator Integrity Assessment Guideline" (Reference 7.7);
- TR-107620, "In-situ Pressure Testing Guideline" (Reference 7.8),
- TR-104788, "PWR Primary-to-Secondary Leak Guideline" (Reference 7.9),
- TR-105714, "Primary Water Chemistry Guideline" (Reference 7.10), and
- TR-102134, "Secondary Water Chemistry Guideline" (Reference 7.11).

These EPRI Guidelines, along with NEI 97-06 (Reference 7.12), tie the entire Steam Generator Program together, while defining a comprehensive, performance based approach to managing SG performance.

In parallel with the industry efforts, the NRC pursued resolution of SG performance issues. In December of 1998, the NRC Staff acknowledged that the Steam Generator Program described by NEI 97-06 and its referenced EPRI Guidelines provides an acceptable starting point to use in the resolution of differences between it and the staff's proposed Generic Letter and draft Regulatory Guide (DG-1074). Since then the industry and the NRC have participated in a series of meetings to resolve the differences and develop the regulatory framework necessary to implement a comprehensive Steam Generator Program.

Revising the existing regulatory framework to accommodate degradation specific management is the most appropriate way to address the issues of regulatory stability, resource expenditure, use of state-of-the-art inservice inspection techniques, repair criteria, and enforceability. The NRC Staff has stated that an integrated approach for addressing SG tube integrity is essential and that materials, systems, and radiological issues that pertain to tube integrity need to be considered in the development of the new regulatory framework.

TSTF-449 supports changes 13, 14, 16, and 18 in Section 2.0 above.

3.4 Post-Modification ILRT

The Callaway Plant containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis loss of coolant accident. Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a pre-stressed reinforced concrete structure with a cylindrical wall, a flat foundation mat with a reactor cavity pit projection, and a hemispherical dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The vertical cylinder wall is provided with a system of vertical and horizontal (hoop) tendons. Vertical tendons are continuous to form inverted U's that extend over the dome. The configuration of the tendons in the dome is based on a three-way system consisting of two groups of vertical tendons oriented at 90 degrees with respect to each other and a horizontal (hoop) group extending from the spring line to approximately 45 degrees from the horizontal. Hoop tendons in both the wall and the dome are placed in a 240 degree system in which three tendons form two complete rings using three buttresses for anchoring the tendons.

During a design basis loss of coolant accident (LOCA) portions of the steam generators and lines emanating from their shells are relied upon to act as a barrier against the uncontrolled release of radioactivity to the environment. As such, the outer shell of the steam generators, the inside containment portions of lines emanating from the steam generator shells (the main steam lines, the main feedwater lines, the steam generator blowdown and sample lines), and the inside surface of the steam generator tubes are all considered part of the containment boundary. All of these components will be impacted by the steam generator replacement activities. Thus, replacing the steam generators will constitute a modification to the containment boundary.

TS 5.5.16.a requires 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. That program is performed in accordance with the guidelines contained in Reference 7.13, NRC Regulatory Guide (RG) 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995. RG 1.163 endorses Reference 7.14, NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," dated July 1995, for methods acceptable to comply with the requirements of Option B. Section 9.2.4 of NEI 94-01 requires that a Type A integrated leakage rate test (ILRT) or local leakage rate testing (LLRT) be conducted prior to returning the containment to operation following a modification that affects the containment leakage integrity. As stated above, replacing the steam generators will constitute a modification to the containment boundary and; therefore, could affect the containment leakage integrity. Given the scope of this design modification, a Type A ILRT would have to be performed. Since the next ILRT is not scheduled to occur until fall 2008 during Refuel 16, in accordance with the requirement of RG 1.163 and NEI 94-01 to perform an ILRT at least once per 10 years (last ILRT was performed in the fall of 1999 during Refuel 10), an additional ILRT would have to be performed unless an exception to this requirement is granted.

This exception is requested to avoid performing an unnecessary ILRT. As discussed in Section 4.4 below, the post-modification ILRT after SG replacement is unnecessary because the ASME Section III/XI pressure test requirements will satisfy the intent of 10 CFR 50, Appendix J, Option B. This exception is similar to that granted in Reference 7.15 to Calvert Cliffs Nuclear Power Plant, Unit No.2, License Amendment 230 dated June 27, 2002. This discussion covers change 17 in Section 2.0 above.

4.0 TECHNICAL ANALYSIS

4.1 Nuclear Steam Supply System Evaluations for Replacement Steam Generators

NSSS Licensing Report

The NSSS licensing report documents the results of analyses and evaluations performed by Westinghouse for the Callaway RSG Program in support of the enclosed TS changes. In addition to the RSG change, the program also considered the incorporation of a vessel average temperature (T-avg) range into the Callaway design basis, as well as an accident analysis re-baseline effort to update analyses. The analyses and evaluations were performed in accordance with the criteria and requirements currently applicable to the Callaway Plant.

The results of the Westinghouse analyses and evaluations demonstrate that applicable licensing criteria and requirements are satisfied for RSG project conditions for those systems, components, and accidents analyses within the Westinghouse scope of supply for this project.

Major Input Assumptions for the NSSS Licensing Report

The Westinghouse analyses and evaluations performed to support the RSG project are based on the following major input assumptions. Additional specific assumptions and acceptance criteria are presented in the appropriate sections of Appendix A to this amendment application.

- Framatome designed Model 73/19T RSGs
- NSSS power level of 3579 MWt (3565 MWt core power)
- The current fuel type of 17x17 V5 remains unchanged
- The current Thermal Design Flow (TDF) of 93,600 gpm/loop is maintained
- Steam Generator Tube Plugging (SGTP) range of 0% to 5%
- A range of nominal feedwater temperatures from 390°F to 446°F
- Full power normal operating T-avg range from 570.7°F to 588.4°F

The analysis of the steam dump valve capacity resulted in a restriction on the proposed T-avg range. The installed steam dump valve capacity is adequate at the RSG conditions, provided that the full-load T-avg is no lower than 573°F.

The T-avg range of 570.7°F to 588.4°F is a change to the current Callaway analysis basis and required additional analytical work to demonstrate the acceptability of the plant. The range was incorporated to allow operating flexibility as well as the capability for an end-of-cycle T-avg coast down.

The analyses and evaluations were performed based on the Westinghouse methods used in the current analyses of record, except as noted below under Analysis Methodologies and Computer Codes.

Westinghouse NSSS Engineering And Analysis Scope

The analyses and evaluations described herein were performed in accordance with the criteria and requirements currently applicable to the Callaway Nuclear Plant. Appendix A to this amendment application documents the Westinghouse analysis areas related to the NSSS for the Callaway RSG project.

Approach and Methodology

The NSSS portion of the overall Callaway RSG project is consistent with established methodology that has been used successfully on many other RSG projects. The analyses and evaluations were performed in conformance with Westinghouse and industry codes, standards, and regulatory requirements applicable to Callaway. The analyses and evaluations of NSSS systems, components, and accident analyses were completed based on NSSS design parameters and the NSSS design transients.

The following approach was used to assess the impact of the RSG conditions on NSSS components for operation at the revised conditions:

- Revise the NSSS design parameters to reflect the impact of the RSG on the design conditions.
- Revise the NSSS design transients (i.e., temperature/pressure profiles) to be applicable to RSG conditions.
- Use the revised NSSS design transient profiles to analyze the NSSS components to determine the fatigue usage factors and stresses for RSG conditions.
- The fatigue usage factors and stresses were then compared to the code acceptance limits to show that the NSSS components comply with American Society of Mechanical Engineers (ASME) Code acceptance criteria and can operate acceptably at RSG conditions.

Analysis Methodologies and Computer Codes

The following non-LOCA transient analyses for the Callaway RSG project use first-time methodology applications.

Excessive Increase in Secondarv Steam Flow Event - FSAR Section 15.1.3

This analysis was addressed by Westinghouse using a statepoint analysis instead of an explicit analysis via the RETRAN code. This transient does not typically result in the actuation of any RTS function (that is, no reactor trip). The effect of this transient on the minimum DNBR was evaluated by applying conservatively large deviations on the initial conditions for power, average coolant temperature, and pressurizer pressure at the normal full-power operating conditions in order to generate a limiting set of state points. These deviations bound the variations that could occur as a result of an excessive load increase incident and are only applied in the direction that had the most adverse impact on DNBR (increased power and coolant temperature, decreased pressure). The reactor condition state points (power, temperature, and pressure) are then compared to the conditions corresponding to operation at the DNB safety analysis limit.

The results of the statepoint analysis performed to support the RSG program show that the acceptance criteria (for example, minimum DNBR) are met. This type of statepoint analysis has been previously used by Westinghouse on other RSG and power uprate projects.

Loss of Normal Feedwater (LONF) Event - FSAR Section 15.2.7

This analysis was addressed by Westinghouse using the RETRAN code. The FSAR Chapter 15 analysis assumes the failure of the turbine-driven auxiliary feedwater (AFW) pump, leaving two motor-driven AFW pumps available to mitigate the event. However, in conjunction with the FSAR analysis, a separate analysis was performed to address the reliability of the AFW system. The reliability analysis is performed in a manner similar to that for the FSAR Chapter 15 analysis, but assumes that only a single motor-driven AFW pump is available to feed two of the four steam generators. The cases considered in this additional reliability analysis assume better-estimate conditions for several key Input parameters. Specifically, initial conditions (NSSS power, RCS pressure and temperature, pressurizer level) and reactor trip and equipment setpoints are assumed to be at their nominal values. Most importantly, a better-estimate decay heat model, consistent with ANS 1971 full decay heat with no uncertainties, was used. This is the first implementation of the dual-analysis approach to separately address FSAR Chapter 15 and AFW system reliability concerns for the loss of normal feedwater event for Callaway. Previously, a single bounding analysis had been performed combining the conservative FSAR Chapter 15-type assumptions and the reduced AFW flow consistent with a single motor-driven AFW pump. That resulted in an analysis that was overly conservative. Utilizing the dual-analysis approach, with both analyses assuming the failure of the turbine-driven AFW pump as the limiting single failure, allows the plant to address both concerns separately, while continuing to show that the conservative acceptance criterion used by Westinghouse for this event (preventing pressurizer filling) is met for both scenarios. By demonstrating that acceptable results are achieved in this separate reliability analysis crediting a single motor-driven AFW pump, the FSAR Chapter 15 analysis can be performed assuming the operation of both available motor-driven AFW pumps. The dual-analysis approach has been previously used by Westinghouse in at least one other loss of normal feedwater analysis for a Westinghouse-designed plant.

The remaining analyses in Appendix A of this amendment application were performed using NRC-approved analytical techniques to demonstrate compliance with the licensing criteria and standards that apply to Callaway. The NRC-approved techniques are the same as those used for current Callaway analyses and are described in the Callaway FSAR, except for the use of three methods new to Callaway. Although these analysis areas employ the first-time application of analysis methods at Callaway, the methods have been approved by NRC. All analysis methods are discussed further in Appendix A to this amendment application.

LOCA Mass and Energy Release

> Westinghouse LOCA Mass and Energy Release Model for Containment Design - March 1979 Version, WCAP-10325-P-A, May 1983 (Refer to Appendix A, Section 6.5)

Non-LOCA, Steam Generator Tube Rupture, and Steam Line Break Mass and Energy Release

> RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, WCAP-14882-P-A, April 1999 (Refer to Appendix A, Sections 6.3, 6.4 and 6.6.1)

Core Thermal-Hydraulic Design

VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, WCAP-14565-P-A, October 1999 (Refer to Appendix A, Section 7.1)

The WCAP references given above have the "-A-" designation included in the report number. This indicates that these methodologies are approved by the NRC and that an NRC Safety Evaluation Report (SER) was issued. The WCAP reports contain the NRC SER or refer to the SER. This project uses these approved methodologies in a manner consistent with the constraints of these SERs.

Radiological Consequences Associated with SG Replacement

Radiological consequences for accidents and transients impacted by the replacement steam generators were calculated using current licensing basis assumptions for such parameters as fuel and rod gap source term inventories, χ/Q atmospheric dispersion factors, breathing rates, control room occupancy fractions and HVAC flow rates, and noble gas (whole body) dose conversion factors (see FSAR Appendix 15A for more details). Thyroid dose conversion factors from ICRP-30 and the iodine spiking model from RG 1.195 (see Reference 7.2) were also used, as approved by NRC for use at Callaway in License Amendment 159 (Reference 7.3).

There are no impacts on the large break LOCA doses reported in FSAR Table 15.6-8. The replacement steam generator project does not affect any of the input assumptions in FSAR Tables 15.6-6 and 15.6-7 for the large break LOCA radiological consequence analysis. Therefore, radiological consequences for large break LOCA were not reanalyzed as a part of the RSG project.

Control room doses remain limiting for large break LOCA; therefore, control room doses are reported only for large break LOCA in the FSAR. All other transients and accidents, including those discussed below, are bounded by large break LOCA.

Radiological consequences were reanalyzed for the following transients and accidents which are affected by the RSG project:

- Main Steam Line Break
- Loss of Non-emergency AC Power to the Station Auxiliaries
- Locked Rotor Accident
- Rod Ejection Accident
- CVCS Letdown Line Break Outside Containment
- Steam Generator Tube Rupture

Both offsite and control room consequences were calculated. These analyses confirmed that the large break LOCA control room radiological consequences currently reported in

Callaway's FSAR remain bounding. Therefore, Callaway's current licensing basis for control room habitability remains valid. The steam generator replacement project will not require Callaway's FSAR to be revised to explicitly report numerical values for control room radiological consequences for the accident sequences listed above.

The NRC Staff has provided a set of considerations that should be addressed regarding control room habitability analyses performed in support of license submittals. These considerations were provided in Regulatory Issue Summary (RIS) 2001-19, *"Deficiencies in the Documentation of Design Basis Radiological Analyses Submitted in Conjunction with License Amendment Requests."*

The following discussion will address the issues from RIS 2001-019:

a. The control room design is often optimized for the DBA LOCA, and the protection afforded for other accident sequences may not be as advantageous. For example, in most designs, control room isolation is actuated by engineered safety feature (ESF) signals such as containment high pressure or safety injection (SI), or radiation monitors, or both. For accidents that rely on radiation monitor actuation, there may be a time delay in isolation that would not occur for the immediate SI signal that would result from a LOCA. In such cases, contaminated air would enter the control room for a longer period preceding isolation than it would for a LOCA.

AmerenUE Response:

Initiation of control room isolation was evaluated for each accident sequence. When appropriate, control room isolation was delayed so that the appropriate mechanism would be credited. The following table lists the accidents analyzed for the steam generator replacement project and the source of control room isolation:

Accident Sequence	Source of Control Room Isolation
Main Steam Line Break	Safety injection signal
Loss of Non-emergency AC Power to the Station Auxiliaries	Control room isolation not credited
Locked Rotor Accident	Isolation credited at 10 minutes to account for time to reach control room intake radiation monitor setpoint and damper stroke time
Rod Ejection Accident	Safety injection signal
CVCS Letdown Line Break Outside Containment	Control room isolation not credited
SGTR ASD Case	SI occurs 597 seconds into the event. Control room isolation is credited at 657 seconds to allow for damper stroke.
SGTR Overfill Case	Control room isolation credited at 60 seconds. Offsite dose methodology initiates a large release at time 0 that would result in the control room intake radiation monitor setpoint being reached at time 0.

b. The configuration of radiation monitors has an impact on their sensitivity. Ideally, the radiation monitors would be located outside in air ventilation intake ductwork. However, there are system designs that place the radiation monitor in recirculation ductwork or downstream of filters. There are also designs that use area radiation monitors. In these latter designs, the contaminated air continues to build up in the control room volume until the concentration is large enough to actuate the radiation monitor.

AmerenUE Response:

Callaway plant's control room intake radiation monitors are located in the normal intake ductwork. These radiation monitors measure concentration of outside air and are not downstream of any filters.

c. In some cases, control room radiation monitor setpoints may have been based on external exposure concerns, for example, 2.5 mrem/hour, rather than thyroid dose from inhalation. The airborne concentration of radioiodines will likely cause elevated thyroid doses before reaching the concentration of all radionuclides necessary to alarm the monitor. This condition is typically seen with accidents that involve a high iodine-to-noble-gas ratio, such as main steam line breaks in PWRs.

AmerenUE Response:

For those sequences analyzed for the steam generator replacement project which credited the control intake radiation monitors, it was verified that the setpoint was reached prior to crediting the isolation signal for those radiation monitors.

d. The distance between the control room and the release point, and the associated wind sectors, may be different for each postulated accident. These differences are usually not significant with regard to offsite doses, but may be significant for control room assessments because of the shorter distances typically involved. The χ/Q for the DBA LOCA may not be applicable to other DBAs. A ground-level release associated with a non-LOCA event may be more limiting than the elevated release associated with LOCAs at plants with secondary containments or enclosure buildings.

AmerenUE Response:

The revised analyses conservatively used the χ/Q values currently provided in Callaway's FSAR for all radiological consequence calculations.

e. Licensees should ensure that assumptions regarding control room isolation and infiltration can be supported by appropriate test results or engineering evaluations. Twenty percent of the licensed power reactors have performed tracer gas tests of control room integrity. All of the tests performed identified as-found infiltration rates greater than those assumed in the design basis calculations.

AmerenUE Response:

Callaway has responded separately to NRC Generic Letter 2003-01 via ULNRC-04885 dated August 11, 2003. Control room in-leakage will be resolved separately from this license submittal.

f. The use of personal respirators or the use of potassium iodide (KI) as a thyroid prophylaxis should not be credited as a substitute for process controls or other engineering controls as discussed in 10 CFR 20.1702.

AmerenUE Response:

The Callaway analysis does not credit respirators or potassium iodide.

Radiological Consequence Conclusions

The replacement steam generators have a minimal impact on the doses calculated for the accidents listed above (i.e., where minimal is defined as an increase that is less than 10% of the margin between the regulatory limit and the currently reported dose). In all cases, the doses associated with this project are less than the applicable regulatory limits.

Containment Pressure / Temperature Response Associated with SG Replacement

The original Callaway containment evaluation model was based on the CONTEMPT code. A new Callaway containment evaluation model, based on the NRC approved containment evaluation model for Kewaunee, was built using the GOTHIC code. Most of the input data for the Callaway GOTHIC containment evaluation model was taken from the CONTEMPT LOCA and MSLB containment model input decks. The GOTHIC LOCA containment evaluation model contains input for service water cooled fan coolers, the containment spray, the major heat sinks, and recirculation cooling. The GOTHIC MSLB containment evaluation model does not require the recirculation cooling input. The GOTHIC code and evaluation model input were compared with the CONTEMPT code and evaluation model input. Differences were identified in modeling condensation heat and mass transfer to the heat sinks, flashing of the liquid break flow, and condensation on the spray droplets. The heat and mass transfer correlations can be changed in GOTHIC to match the CONTEMPT models; however, GOTHIC does not have the same flashing or spray condensation models as CONTEMPT. To determine the effect of these differences, the GOTHIC Callaway containment evaluation model was modified for benchmark comparisons with the original CONTEMPT LOCA and MSLB containment evaluation models. In addition to various input changes required to add the mass and energy releases and change the heat transfer correlations, a circular flow path with drop de-entrainment was used to simulate the temperature flash option in CONTEMPT and the containment spray drop diameter input value was reduced by a factor of 10 to simulate the 100% spray efficiency in CONTEMPT. With these benchmarking changes, the GOTHIC model results were reasonably close to those predicted by CONTEMPT. For the LOCA event, GOTHIC predicted a 2.9 psi higher peak pressure and a slightly lower (1.0°F) peak temperature. For the MSLB event, GOTHIC predicted a 4.36 psi higher peak pressure for the peak MSLB pressure case and a slightly lower (2.95°F) peak temperature for the peak MSLB temperature case.

The GOTHIC Callaway containment evaluation model was used to produce sample results for the LOCA and MSLB transients using conservative mass and energy release data that is representative of Callaway.

A double-ended hot leg LOCA was assumed to be initiated from full power. A loss of offsite power and failure of an emergency diesel generator was assumed. In this analysis containment spray starts to inject at 44.74 seconds and the containment fan coolers start to remove heat at 61 seconds. The calculated peak containment pressure was 46.25 psig at 24 seconds. This is less than the containment design pressure of 60 psig and less than the peak pressure currently listed in FSAR Table 6.2.1-8 for LOCA Case 1 (47.3 psig) which will continue to be reported in the FSAR and used in all future operability determinations and 10 CFR 50.59 evaluations. The difference between 47.3 psig and 46.25 psig will be treated as available margin. The containment temperature remained less than 270° F for the entire transient. This is less than the peak temperature currently listed in FSAR Table 6.2.1-8 for LOCA Case 2 (308.6°F) which will continue to be reported in the FSAR and used in all future operability determinations and 10 CFR 50.59 evaluations. The difference between 308.6°F and 270°F will be treated as available margin.

The limiting MSLB event in terms of containment pressure is a split break at 0% power. A loss of one containment spray pump and two containment fan coolers (one train of containment cooling) was assumed. In this analysis the fan coolers start to remove heat at 74.2 seconds and containment spray starts to inject at 227.9 seconds. The peak containment pressure for this case was 44.8 psig at 605 seconds. This is less than the containment design pressure of 60 psig and less than the peak pressure currently listed in FSAR Table 6.2.1-58 for MSLB Case 12 (48.1 psig) which will continue to be reported in the FSAR and used in all future operability determinations and 10 CFR 50.59 evaluations. The difference between 48.1 psig and 44.8 psig will be treated as available margin. The limiting MSLB event in terms of containment temperature is a double ended rupture at 102% power. An MSIV failure was assumed for this case. In this analysis the fan coolers start to remove heat at 63.1 seconds and containment spray starts to inject at 65.9 seconds. The peak temperature for this case was 352.8° F at 190 seconds. This is less than the peak temperature currently listed in FSAR Table 6.2.1-58 for MSLB LOCA Case 6 (384.9°F) which will continue to be reported in the FSAR and used in all future operability determinations and 10 CFR 50.59 evaluations. The difference between 384.9°F and 352.8°F will be treated as available margin.

Therefore, there will be no adverse impact on containment design or the qualification of equipment required to operate inside containment.

4.2 TTD Elimination

This evaluation will address the impact of the trip time delay elimination in the following areas.

<u>Instrumentation and Control</u>

The 7300 Process Protection System cabinets will be modified to eliminate the trip time delay function. The 7300 Process Protection System is part of the reactor protection system. The plant commitments in FSAR Section 7.1 to IEEE-279-1971 will continue to be met after the trip time delay function is eliminated from the 7300 Process Protection System.

This modification will be accomplished by removing and/or modifying printed circuit cards and associated interconnecting wiring in the four 7300 Process Protection System cabinets.

Removal of the above hardware is a plant enhancement that increases reliability of the 7300 Process Protection System because of the reduced number of electrical components in the system. Removal of the above trip time delay hardware also eliminates the required periodic testing of this function.

Compliance with IEEE-279-1971

Section 4.2, "Single Failure Criterion"

Changes to each of the four 7300 Process Protection cabinets will eliminate the trip time delay function. This modification will be accomplished by removing and/or modifying printed circuit cards and interconnecting wiring in each of the four 7300 cabinets. The changes will be internal to the 7300 cabinets and no new interfaces will be established with any other system. Redundancy in the 7300 Process Protection System cabinets will be maintained after elimination of the trip time delay circuit.

Section 4.4, "Equipment Qualification"

Changes to each of the four 7300 Process Protection cabinets will eliminate the trip time delay function. This modification will be accomplished by removing and/or modifying printed circuit cards and interconnecting wiring in each of the four 7300 cabinets. These changes will not adversely impact the qualification of the 7300 Process Protection System discussed in WCAP-8587 and WCAP-8687, which document the seismic and environmental qualification of the 7300 Process Protection System cabinets and printed circuit cards to IEEE-344-1975 and IEEE-323-1974, respectively.

Section 4.6, "Channel Independence"

The electrical independence and physical separation in the 7300 Process Protection System cabinets will not be changed as a result of eliminating the trip time delay function. There will be no external cable rerouting required due to elimination of the trip time delay function. In addition, power input to the 7300 Process Protection cabinets will not be changed.

Section 4.7, "Control and Protection System Interaction"

Elimination of the trip time delay will not adversely impact the reactor trip signal on low-low steam generator water level, the auxiliary feedwater pump startup signal or the feedwater isolation signal. The two-out-of-four low-low steam generator water level logic trip will not be changed as a result of the elimination of the trip time delay. In addition, the electrical isolation devices provided for control and protection interaction will not be changed as a result of elimination of the trip time delay.

LOCA Mass and Energy Releases

The long term LOCA mass and energy releases are most sensitive to increases in the RCS temperatures, pressures, fluid volumes, and core stored energy, decay heat, and reductions in Thermal Design Flow. None of these conditions is changing as a result of implementing the trip time delay elimination.

Main Steamline Break Mass and Energy Releases And Steam Releases For Doses

The main steamline break mass and energy (M&E) releases and the steam releases for radiological doses do not assume any operation of the trip time delay in the analyses. There are no inputs, assumptions or boundary conditions related to the trip time delay elimination that affect the steam break related analyses.

LOCA and LOCA Related Analyses

Implementing the trip time delay elimination will not affect the plant operating parameters, the safeguards systems actuation or accident mitigation capabilities important to a LOCA or the assumptions used in the LOCA-related accidents. It will not create conditions more limiting than those assumed in these analyses.

Non-LOCA Analyses

The trip time delay is supported in the current Chapter 15 non-LOCA transients via the analysis of part-power Loss of Normal Feedwater and Feedline Break cases with increased delays for reactor trip on a low-low steam generator water level signal. The increase in reactor trip time delay results in part-power cases that are nearly as limiting as the full-power case with a typical trip time delay of 2 seconds.

For the RSG, the removal of the trip time delay simply means that the typical 2 second trip time delay will apply at all power levels, making the full-power conditions the most limiting. Explicit reanalysis of the events which previously took credit for the TTD feature (Loss of Normal Feedwater and Feedline Break) has been performed as part of the analyses discussed in Section 4.1 above and in Appendix A to this amendment application. As such, only full-power conditions have been considered. Based on this, the removal of the trip time delay, in conjunction with the implementation of the RSG, will be consistent with the updated Callaway FSAR Chapter 15 non-LOCA licensing basis analyses in Appendix A to this amendment application.

Steam Generator Tube Rupture (SGTR) And Rod Ejection Steam Releases

Implementing the trip time delay elimination will not affect the NSSS performance parameters, input assumptions, results, or conclusions of the SGTR thermal and hydraulic analyses (break flow/steam release). Also, conditions will not be created which are more limiting than those enveloped by the current analysis break flow/steam release.

NSSS Design Transients

The implementation of the TTD elimination, of itself, will have no impact on the NSSS design transients. The design transients used for component fatigue stress analysis are not changed as a result of TTD elimination.

Control Systems Operability/Margin to Trip Analyses

The implementation of the TTD elimination, of itself, will not impact the control systems operability. Therefore, the plant behavior during at-power steady state operation and plant response during the design basis operational transients will not be affected due to this elimination. The plant margin to trip during the operational transients will not be affected by this elimination. There is no need to revise any control system setpoints for this modification.

Cold Overpressure Mitigation System (COMS)

The NSSS design parameters will not be revised for the implementation of the TTD elimination. Cold overpressure mitigation is designed for reactor vessel embrittlement concerns and the design bases are not changing due to the TTD elimination. Thus, there will be no impact on the COMS setpoint or results.

Engineering Evaluations Conclusion

The steam generator water level low-low trip function currently allows a lower trip setpoint under normal containment environmental conditions and a delayed trip when THERMAL POWER is less than or equal to 22.41% RTP. The 7300 Process Protection System is being modified to eliminate the trip time delay function. The function performed by the EAM will remain unchanged after the trip time delay is eliminated. Elimination of the trip time delay function in the 7300 Process Protection System will not adversely impact the Callaway plant commitments to IEEE-279-1971. No safety-related functions will be adversely impacted due to this change.

Elimination of the trip time delay will not adversely impact the two-out-of-four logic for the reactor trip signal on low-low steam generator water level, the auxiliary feedwater pump startup signal or the feedwater isolation signal. The changes will be internal to the 7300 Process Protection cabinets. There will be no external cable re-routing required due to this change. In addition, the 7300 Process Protection System equipment qualification, electrical isolation, and redundancy will not be affected due to elimination of the trip time delay.

The accident analysis acceptance criteria for the licensing basis as documented in the FSAR, and updated for RSG conditions in Appendix A of this amendment application, will be unaffected by the TTD elimination.

4.3 TSTF-449 Generic Licensing Change Package

The proposed changes in TSTF-449 do not affect the method of operation of the steam generators nor the primary or secondary coolant chemistry controls. The primary coolant activity limit and its assumptions are not affected by the proposed TS changes. The proposed changes are an improvement to the existing SG inspection requirements and provide additional assurance that the plant licensing basis will be maintained between SG inspections.

A steam generator tube rupture (SGTR) event is one of the design basis accidents that are analyzed as part of a plant's licensing basis. The analysis of SGTR cases for Callaway assumes a bounding primary to secondary LEAKAGE rate of 1 gpm in the unaffected steam generators, in excess of the RCS Operational LEAKAGE rate limit in TS 3.4.13, plus the leakage rate associated with a double-ended rupture of a single tube in the ruptured SG.

For design basis accidents such as main steam line break (MSLB), rod ejection, and reactor coolant pump locked rotor, the SG tubes are assumed to retain their structural integrity (i.e., they are assumed not to rupture). These analyses assume that primary to secondary LEAKAGE for all SGs is 1 gallon per minute. For accidents that do not involve fuel damage, the reactor coolant activity levels are at the TS values. For accidents that do involve fuel damage, the primary coolant activity values are a function of the amount of activity released from the damaged fuel. The consequences of these design basis accidents are, in part, functions of the radioactivity levels in the primary coolant and the accident primary to secondary LEAKAGE rates. As a result, limits are included in the TS for RCS Operational LEAKAGE and for DOSE EQUIVALENT I-131 in the primary coolant to ensure the plant is operated within its analyzed condition. The current TS limit of 150 gallons per day of primary to secondary LEAKAGE through any one SG is based on operating experience as an indication of one or more tube leaks. This LEAKAGE limit provides assurance that leaking flaws will not propagate to burst prior to plant shutdown. The TS changes proposed in this amendment application are, in general, a significant improvement over the existing TS requirements. They replace an outdated prescriptive technical specification with one that references Steam Generator Program requirements that incorporate the latest knowledge of SG tube degradation morphologies and the techniques developed to manage them. The requirements being proposed are more effective in detecting SG degradation and prescribing corrective actions than required by existing TS. As a result, the proposed changes will result in added assurance of the function and integrity of SG tubes.

RCS Operational LEAKAGE

The primary to secondary LEAKAGE limit was previously reduced to 150 gallons per day through any one SG in Callaway Amendment 116 dated October 1, 1996. This leakage rate limit provides assurance against tube rupture at normal operating and faulted conditions. This together with the allowable accident induced leakage limit helps to ensure that the dose contribution from tube leakage will be limited to less than the licensing basis limits for postulated faulted events.

This limit also contributes to meeting the GDC-14 requirement that the reactor coolant pressure boundary "have an extremely low probability of abnormal leakage, of rapidly propagating to failure, and of gross rupture." The revised Bases change for SR 3.4.13.2 references the Steam Generator Program. The Steam Generator Program uses the EPRI Primary-to-Secondary Leak Guideline (Reference 7.9) to establish sampling requirements for determining primary to secondary LEAKAGE and plant shutdown requirements if leakage limits are exceeded. The guidelines ensure leakage is effectively monitored and timely action is taken before a leaking tube exceeds the performance criteria. The Frequency for determining primary to secondary LEAKAGE is unchanged (i.e., 72 hours and within 12 hours after establishing steady state operating conditions).

The existing TS requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is physically more conservative than the analysis limit of 1 gpm total primary to secondary LEAKAGE through all SGs, used as initial condition in the radiological consequence analyses. From a dose consequence perspective, use of the 1 gpm leak rate is conservative.

RCS Operational LEAKAGE Actions

If primary to secondary LEAKAGE exceeds 150 gallons per day through any one SG, a plant shutdown must be commenced. MODE 3 must be achieved in 6 hours and MODE 5 in 36 hours. The existing TS allow 4 hours to reduce primary to secondary LEAKAGE to less than the limit. The proposed TS 3.4.13 change removes this allowance.

The removal of the 4 hour period during which primary to secondary LEAKAGE can be reduced to avoid a plant shutdown results in a TS that is significantly more conservative than the existing RCS Operational LEAKAGE specification. This change is consistent with the Steam Generator Program that also does not allow 4 hours before commencing a plant shutdown.

RCS Operational LEAKAGE Determined by Water Inventory Balance

The proposed change adds a second Note to SR 3.4.13.1 that makes the water inventory balance method not applicable to determining primary to secondary LEAKAGE. This change is proposed because primary to secondary LEAKAGE as low as 150 gallons per day through any one SG cannot be measured accurately by an RCS water inventory balance.

SG Tube Integrity Verification

The current SR 3.4.13.2 requires verification of tube integrity in accordance with the SG Tube Surveillance Program. This surveillance is no longer appropriate since tube integrity is addressed through the addition of new TS 3.4.17, SG Tube Integrity. Specification 3.4.13 now applies specifically to primary to secondary LEAKAGE. SR 3.4.13.2 has been changed to verify the LCO requirement on primary to secondary LEAKAGE only. Steam generator tube integrity is verified in accordance with SR 3.4.17.1 in new TS 3.4.17.

The Steam Generator Program and the EPRI "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines" (Reference 7.9) provide guidance on leak rate monitoring. During normal operation the program depends upon continuous process radiation monitors and/or radiochemical grab sampling. The monitoring and sampling frequency increases as the amount of detected LEAKAGE increases or if there are no continuous radiation monitors available.

Primary to secondary LEAKAGE is determined through the analysis of secondary coolant activity levels. At low power, primary and secondary coolant activity is sufficiently low that an accurate determination of primary to secondary LEAKAGE may be difficult. Immediately after shutdown, some of the short lived isotopes are usually at sufficient levels to monitor for LEAKAGE by normal power operational means as long as other plant conditions allow the measurement. During startup, especially after a long outage, there are no short lived isotopes in either the primary or secondary system. This limits measurement of the LEAKAGE to chemical or long lived radiochemical means. Because of these effects, an accurate primary to secondary leakage measurement is highly dependent upon plant conditions and may not be obtainable prior to reactor criticality (e.g., MODES 1 and 2). If SG water samples are less than the minimum detectable activity for each principal gamma emitter, primary to secondary LEAKAGE may be assumed to be less than or equal to 150 gallons per day through any one SG.

Determination of the primary to secondary LEAKAGE is required every 72 hours. Revised SR 3.4.13.2 is modified by a Note stating the SR is not required to be performed until 12 hours after establishment of steady state operating conditions. As stated above, additional monitoring of primary to secondary LEAKAGE is also required by the Steam Generator Program based upon guidance provided in Reference 7.9.

Frequency of Verification of SG Tube Integrity

The existing TS contain prescriptive inspection intervals which depend on the condition of the tubes as determined by the last SG inspection. The tube condition is classified into one of three categories based on the number of tubes found degraded and defective. The minimum inspection interval is no less than 12 and no more than 24 months unless the results of two consecutive inspections are in the best category (no additional degradation), and then the interval can be extended to 40 months. The surveillance Frequency in the proposed TS 3.4.17 on Steam Generator Tube Integrity is governed by the requirements in the Steam Generator Program and specifically by References 7.6 and 7.7. The proposed Frequency is also prescriptive, but has a stronger engineering basis than the existing TS requirements. The interval is dependent on tubing material and whether any active degradation is found. The interval is limited by existing and potential degradation mechanisms and their anticipated growth rate. In addition, a maximum inspection interval is established in revised Specification 5.5.9.

The maximum inspection interval for Alloy 690 thermally treated tubing is:

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

Even though the maximum interval for Alloy 690 thermally treated tubing is slightly longer than allowed by existing TS, it is only applicable to SGs with advanced materials such as the RSGs being installed during Refuel 14, it is only achievable early in SG life and only if the SGs are free from active degradation. In addition, the interval must be supported by an evaluation that shows that the performance criteria will continue to be met at the next SG inspection. Taken in total, the proposed inspection intervals provide a larger margin of safety than the current requirements because they are based on an engineering evaluation of the tubing condition and potential degradation mechanisms and growth rates, not only on the previous inspection results. As an added safety measure, the Steam Generator Program requires a minimum sample size at each inspection that is significantly larger than that required by existing TS (20 percent versus 3 percent times the number of SGs in the plant); thus providing added assurance that any degradation within the SGs will be detected and accounted for in establishing the inspection interval.

The proposed maximum inspection intervals are based on the historical performance of advanced SG tubing materials. Reference 7.16 shows that the performance of Alloy 690TT is significantly better than the performance of 600MA tubing, the material used in SG tubing at the time that the Standard TS were written. There are no known instances of cracking in 690TT tubes in either the U.S. or international SGs.

In summary, the proposed change is an improvement over the existing TS. The existing TS correlates inspection intervals to the results of previous inspections; it does not require an evaluation of expected performance. The proposed TS changes use information from previous plant inspections as well as industry experience to evaluate the length of time that the SGs can be operated and still provide reasonable assurance that the performance criteria will be met at the next inspection. The actual interval is the shorter of the evaluation results and the requirements in Reference 7.7. Allowing plants to use the proposed inspection intervals maximizes the potential that plants will use improved techniques and knowledge since better knowledge of SG conditions supports longer intervals.

SG Tube Sample Selection

The existing TS base tube selection on SG conditions and industry and plant experience. The minimum sample size is 3% of the tubes times the number of SGs in the plant. The proposed change refers to the Steam Generator Program degradation assessment guidance for sampling requirements. The minimum sample size is 20% of all the tubes in the four steam generators.

The Steam Generator Program requires the preparation of a degradation assessment before every SG inspection. The degradation assessment is the key document used for planning a SG inspection, where inspection plans and related actions are determined, documented, and communicated prior to the outage. The degradation assessment addresses the various reactor coolant pressure boundary components within the SG (e.g., plugs, tubes, and components that support the pressure boundary). In a degradation assessment, tube sample selection is performance based and is dependent upon actual SG conditions and plant operational experience and of the industry in general. Existing and potential degradation mechanisms and their locations are evaluated to determine which tubes will be inspected. Tube sample selection is adjusted to minimize the possibility that tube integrity might degrade during an operating cycle beyond the limits defined by the performance criteria. The EPRI Steam Generator Examination Guidelines (Reference 7.6) and EPRI Steam Generator Integrity Assessment Guidelines (Reference 7.7) provide guidance on degradation assessment.

In general, the sample selection considerations required by the existing TS and the requirements in the Steam Generator Program as proposed herein are consistent, but the Steam Generator Program provides more guidance on selection methodologies and incorporation of industry experience and requires more extensive documentation of the results. Therefore the sample selection method proposed herein is more conservative than the existing TS requirements. In addition, the minimum sample size in the proposed requirements is larger.

SG Inspection Techniques

The Surveillance Requirements proposed in new TS 3.4.17 require that tube integrity be verified in accordance with the requirements of the Steam Generator Program. The Steam Generator Program uses the EPRI Steam Generator Examination Guidelines (Reference 7.6) to establish requirements for qualifying NDE techniques and maintains a list of qualified techniques and their capabilities.

The Steam Generator Program requires the performance of a degradation assessment before every SG inspection and refers utilities to EPRI Steam Generator Examination Guidelines (Reference 7.6) and EPRI Steam Generator Integrity Assessment Guidelines (Reference 7.7) for guidance on its performance. The degradation assessment will identify current and potential new degradation locations and mechanisms and NDE techniques that are effective in detecting their existence. Tube inspection techniques are chosen to reliably detect flaws that might progress during an operating cycle beyond the limits defined by the performance criteria.

SG Inspection Scope

The existing TS include a definition of inspection that specifies the end points of the eddy current examination of each tube. Typically an inspection is required from the point of entry of the tube on the hot leg side to some point on the cold leg side of the tube, usually at the first tube support plate after the U-bend. This definition is overly prescriptive and simplistic and has led to interpretation questions in the past.

The Steam Generator Program states:

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

The Steam Generator Program provides extensive guidance and a defined process, the degradation assessment, for determining the extent of a tube inspection. This guidance takes into account industry and plant specific history to determine potential degradation mechanisms and the location that they might occur within the SG. This information is used to define a performance based inspection scope targeted on plant specific conditions and SG design.

The proposed change is an improvement over the existing TS because it focuses the inspection effort on the areas of concern, thereby minimizing the unnecessary data that the NDE analyst must review to identify indication of tube degradation.

SG Performance Criteria

The proposed change adds TS 5.5.9, a performance-based Steam Generator Program. A performance-based approach has the following attributes:

- measurable parameters;
- objective criteria to assess performance based on risk-insights;
- deterministic analysis and/or performance history; and
- licensee flexibility to determine how to meet established performance criteria.

The performance criteria used for SGs are based on tube structural integrity, accident induced leakage, and operational LEAKAGE. The structural integrity and accident induced leakage criteria were developed deterministically and are consistent with the plant's licensing basis. The operational LEAKAGE criterion was based on providing added assurance against tube rupture at normal operating and faulted conditions. The proposed structural integrity and accident induced leakage performance criteria are new requirements. The performance criteria are specified in revised TS 5.5.9. The requirements and methodologies established to meet the performance criteria are documented in the Steam Generator Program. The existing TS contain only the operational LEAKAGE criterion; therefore the proposed change is more conservative than the current requirements.

The SG performance criteria identify the standards against which performance is to be measured. Meeting the performance criteria provides reasonable assurance that the SG tubing will remain capable of fulfilling its specific safety function of maintaining RCPB integrity throughout each operating cycle.

The structural integrity performance criterion is:

"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, and cooldown, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 (3ΔP) against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads."

The structural integrity performance criterion is based on providing reasonable assurance that a SG tube will not burst during normal operation or postulated accident conditions. Adjustments to include contributing loads are addressed in the applicable EPRI guidelines.

Normal steady state full power operation is defined as the conditions existing during MODE 1 operation at the maximum steady state reactor power as defined in the design or equipment specification. Changes in design parameters such as plugging levels, primary or secondary modifications, or T-Hot should be assessed and included if significant.

The definition of normal steady state full power operation is important as it relates to application of the safety factor of three in the structural integrity performance criterion. The criterion requires "...retaining a safety factor of 3.0 (3ΔP) under normal steady state full power operation primary to secondary pressure differential..." The application of the safety factor of three to normal steady state full power operation is founded on past NRC positions, accepted industry practice, and the intent of the ASME Code for original design and evaluation of inservice components. The assumption of normal steady state full power operating pressure differential has been consistently used in the analysis, testing and verification of tubes with stress corrosion cracking for verifying a safety factor of three against burst. Additionally, the 3ΔP criterion is measurable through the condition monitoring process.

The actual operational parameters may differ between cycles. As a result of changes to these parameters, reaching the differential pressure in the equipment specification may not be possible during plant operations. Evaluating to the pressure in the design or equipment specification in these cases would be an unnecessary conservatism. Therefore, the definition allows adjustment of the 3ΔP limit for changes in these parameters when necessary. Further guidance on this adjustment is provided in Appendix M of the EPRI Steam Generator Integrity Assessment Guidelines (Reference 7.7).

The accident induced leakage performance criterion is:

"The primary to secondary accident induced leakage rate for all design basis accidents, other than a steam generator tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all steam generators and leakage rate for an individual steam generator. Leakage is not to exceed 1 gpm total for all four steam generators."

Primary to secondary LEAKAGE is a factor in the activity releases outside containment resulting from a limiting design basis accident. The potential dose consequences from primary to secondary LEAKAGE during postulated design basis accidents must not exceed the radiological limits imposed by licensing basis requirements.

The analyses for design basis accidents and transients other than a steam generator tube rupture assume a total of 1 gpm primary to secondary LEAKAGE as an initial condition. Recent experience with degradation mechanisms involving tube cracking has revealed that leakage under accident conditions can exceed the level of operating leakage by orders of magnitude. The NRC has concluded (Item Number 3.4 in Attachment 1 to Reference 7.17) that additional research is needed to develop an adequate methodology for fully predicting the effects of leakage on the outcome of some accident sequences. Therefore, a separate performance criterion was established for accident induced leakage. The limit for accident induced leakage at Callaway is 1 gpm.

The operational LEAKAGE performance criterion is:

"The RCS Operational primary to secondary LEAKAGE through any one steam generator shall be limited to 150 gallons per day."

Plant shutdown will commence if primary to secondary LEAKAGE exceeds 150 gallons per day at room temperature conditions from any one SG. The operational LEAKAGE performance criterion is documented in the Steam Generator Program and implemented in TS 3.4.13, "RCS Operational LEAKAGE." Changes proposed to TS 5.5.9 contain the performance criteria and is more conservative than the existing TS. The existing TS do not address the structural integrity and accident induced leakage criteria.

<u>SG Repair Criteria</u>

Repair criteria are those NDE measured parameters at or beyond which the tube must, for the Callaway RSGs, be removed from service by plugging.

Tube repair criteria are established for each active degradation mechanism. Tube repair criteria are either the standard through-wall depth-based criterion (e.g., 40% through-wall for Callaway) or through-wall depth based criteria for repair techniques approved by the NRC, or other Alternate Repair Criteria (ARC) approved by the NRC such as a voltage-based repair limit per Generic Letter 95-05 (Reference 7.18). A SG degradation-specific management strategy is followed to develop and implement an ARC. Previously approved tube sleeving techniques have not been approved by NRC as applicable to the RSGs and, therefore, have been deleted in revised TS 5.5.9.

The surveillance requirements of the proposed Steam Generator Tube Integrity TS 3.4.17 require that tubes that satisfy the tube repair criteria be plugged since Callaway has not licensed an ARC for the replacement steam generators yet to be installed. SG tubes experiencing a damage form or mechanism for which no depth sizing capability exists are "repaired/plugged-on-detection" and their integrity assessed. It cannot be guaranteed that every flaw will be detected with a given eddy current technique and, therefore, it is possible that some flaws will not be detected during an inspection. If a flaw is discovered and it is determined that this flaw would have satisfied the repair criteria at the time of the last inspection of the affected tube, this does not mean that the Steam Generator Program was violated.

Any plant-specific alternate repair criteria approved in the future by NRC would be listed in Technical Specification 5.5.9 upon approval.

Actions

The RCS Operational LEAKAGE and Steam Generator Tube Integrity specifications require the plant to monitor SG performance against performance criteria in accordance with the Steam Generator Program.

During plant operation, monitoring is performed using the operational LEAKAGE criterion. Exceeding that criterion will lead to a plant shutdown in accordance with Technical Specification 3.4.13. Once shutdown, the Steam Generator Program will ensure that the cause of the operational LEAKAGE is determined and corrective actions are taken to prevent recurrence. Operation may resume when the requirements of the Steam Generator Program have been met. This requirement is unchanged from the existing TS.

Also during plant operation the plant may discover an error or omission that indicates a failure to implement a required plugging or repair during a previous SG inspection. Under these circumstances, the plant would take the actions required by Condition A in the new Steam Generator Tube Integrity TS 3.4.17. If a performance criterion has been exceeded, a principal safety barrier has been challenged and 10 CFR 50.72(b)(3)(ii)(A) and 50.73(a)(2)(ii)(A) require NRC notification and the submittal of a report containing the cause and corrective actions to prevent recurrence. The Steam Generator Program additionally requires that the report contain information on the performance criteria exceeded and the basis for the planned operating cycle. The existing TS only address RCS Operational LEAKAGE during operations and therefore do not include the proposed requirement.

During MODES 5 and 6, the RCS Operational LEAKAGE criterion is not applicable, and the SGs will be inspected as required by the surveillance in the Steam Generator Tube Integrity specification. A condition monitoring assessment of the "as found" condition of the SG tubes will be performed to determine the condition of the SGs with respect to the structural integrity and accident leakage performance criteria. If the performance criteria are not met, the Steam Generator Program requires ascertaining the cause and determining corrective actions to prevent recurrence. Operation may resume when the requirements of the Steam Generator Program have been met.

The proposed TS change to the ACTIONS required upon exceeding the operational leakage criterion is conservative with respect to the existing TS. The existing TS do not address ACTIONS required while operating if it is discovered that the structural integrity or accident induced leakage performance criteria or a repair criterion are exceeded, so the proposed change is conservative with respect to the existing TS.

If performance or repair criteria are exceeded while shutdown, the affected tubes must be plugged at Callaway. If the number of degraded tubes exceeds 1% of those inspected in any SG, a report will be submitted to the NRC in accordance with revised TS 5.6.10. The changes in the required reports are discussed below.

SG Repair Methods

Repair methods are those means used to reestablish the RCS pressure boundary integrity of SG tubes without removing the tube from service. Plugging a SG tube is not a repair.

The purpose of a repair is typically to reestablish or replace the RCPB. The proposed Steam Generator Tube Integrity surveillance requirements in new TS 3.4.17 require that tubes that satisfy the tube repair criteria be plugged at Callaway in accordance with the Steam Generator Program. There are no repair methods listed in revised TS 5.5.9 for the replacement steam generators yet to be installed at Callaway.

Steam generator tubes experiencing a damage form or mechanism for which no depth sizing capability exists are "repaired/plugged-on-detection" and their integrity is assessed. This requirement is unchanged by the proposed TS revisions.

Note that SG plug designs do not require NRC review and, therefore, plugging is not considered a repair in the context of this requirement. The proposed approach is not a change to the existing TS.

Reporting Requirements

The existing TS require the following reports:

- A report listing the number of tubes plugged or repaired in each SG submitted within 15 days of the end of the inspection.
- A SG inspection results report submitted within 12 months after the inspection.
- Reports required pursuant to 10 CFR 50.73.

The proposed changes to TS 5.6.10 replace the 15 day and the SG inspection reports with one report required within 180 days if greater than one percent of the tubes inspected in any one SG exceed a repair criterion. The proposed report also contains more information than the current SG inspection report. This provision limits the reports submitted to the NRC to those documenting more extensive degradation, requires that the reports that are submitted provide more substantive information and be sent earlier (180 days versus 12 months). This allows the NRC to focus its attention on the more significant conditions.

The guidance in NUREG-1022, Rev. 2, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," identifies serious SG tube degradation as an example of an event or condition that results in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded. Steam generator tube degradation is considered serious if the tubing fails to meet structural integrity and accident induced leakage performance criteria. Serious SG tube degradation would be reportable in accordance with 10 CFR 50.72(b)(3)(ii)(A) and 50.73(a)(2)(ii)(A) requiring NRC notification and the submittal of a report containing the cause and corrective actions to prevent recurrence.

The proposed reporting requirements are an improvement as compared to those required by the existing TS. The proposed reporting requirements are more useful in identifying the degradation mechanisms and determining their effects. In the unlikely event that a performance criterion is not met, NEI 97-06 (Reference 7.12) directs the licensee to submit additional information on the root cause of the condition and the basis for the next operating cycle.

The changes to the reporting requirements are performance based. The new requirements remove the burden of unnecessary reports from both the NRC and the licensee, while ensuring that critical information related to problems and significant tube degradation is reported more completely and, when required, more expeditiously than under the existing TS.

SG Terminology

The proposed Bases for new TS 3.4.17, "Steam Generator Tube Integrity," explain a number of terms that are important to the function of a Steam Generator Program. The terms are described below.

1. Accident induced leakage rate means the primary to secondary LEAKAGE rate occurring during postulated accidents other than a steam generator tube rupture. This includes the primary to secondary LEAKAGE rate existing immediately prior to the accident plus additional primary to secondary LEAKAGE induced during the accident.

   Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a limiting design basis accident. The potential primary to secondary leak rate during postulated design basis accidents must not cause radiological dose consequences in excess of approved licensing basis limits.

2. The LCO section of the bases for new TS 3.4.17 defines the term "burst" as "the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation."

   Since a burst definition is required for condition monitoring, a definition that can be analytically defined and is capable of being assessed via in situ and laboratory testing is necessary. Furthermore, the definition must be consistent with ASME Code requirements, and apply to most forms of tube degradation.

   The definition developed for tube burst is consistent with the testimony of James Knight (Reference 7.19), and the historical guidance of draft Regulatory Guide 1.121 (Reference 7.20). The definition of burst per these documents is in relation to gross failure of the pressure boundary; e.g., "the degree of loading required to burst or collapse a tube wall is consistent with the design margins in Section III of the ASME B&PV Code (Reference 7.21)." Burst, or gross failure, according to the Code would be interpreted as a catastrophic failure of the pressure boundary.

The above definition of burst was chosen for a number of reasons:

- The burst definition supports field application of the condition monitoring process. For example, verification of structural integrity during condition monitoring may be accomplished via in situ testing. Since these tests do not have the capability to provide an unlimited water supply, or the capability to maintain pressure under certain leakage scenarios, opening area may be more a function of fluid reservoir rather than tube strength. Additionally, in situ designs with bladders may not be reinforced. In certain cases, the bladder may rupture when tearing or extension of the defect has not occurred. This condition may simply mean the opening of the flanks of the defect was sufficient to permit extrusion of the bladder, and that the actual, or true, burst pressure was not achieved during the test. The burst definition addresses this issue.

- The definition does not characterize local instability or "ligament pop-through", as a burst. The onset of ligament tearing need not coincide with the onset of a full burst. For example, an axial crack about 0.5" long with a uniform depth at 98% of the tube wall would be expected to fail the remaining ligament (i.e., extend the crack tip in the radial direction) due to deformation during pressurization at a pressure below that required to cause extension at the tips in the axial direction. Thus, this would represent a leakage situation as opposed to a burst situation and a factor of safety of three against crack extension in the axial direction may still be demonstrated. Similar conditions have been observed for deep wear indications.

3. The LCO section of the new TS 3.4.17 Bases defines a SG tube as, "the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube."

This definition ensures that all portions of SG tubes that are part of the RCPB, with the exception of the tube-to-tubesheet weld, are subject to Steam Generator Program requirements. The definition is also intended to exclude tube ends that can not be NDE inspected by eddy current. If there are concerns in the area of the tube end, they will be addressed by NDE techniques if possible or by using other methods if necessary.

For the purposes of SG tube integrity inspection, any weld metal in the area of the tube end is not considered part of the tube. This is necessary since the acceptance requirements for tubing and weld metals are different.

4. The LCO section of the new TS 3.4.17 Bases defines the term "collapse" as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero."

   In dealing with pure pressure loadings, burst is the only failure mechanism of interest. If bending loads are introduced in combination with pressure loading, the definition of failure must be broadened to encompass both burst and bending collapse. Which failure mode applies depends on the relative magnitude of the pressure and bending loads and also on the nature of any flaws that may be present in the tube. Guidance on assessing applicable failure modes is provided in the EPRI steam generator guidelines.

5. The LCO section of the new TS 3.4.17 Bases defines the term "significant" as used in the structural integrity performance criterion as "An accident loading condition other than differential pressure is considered 'significant' when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established."

6. The LCO section of the new TS 3.4.17 Bases describes how to determine whether thermal loads are primary or secondary loads. The description is based on the ASME definition in which secondary loads are self-limiting and will not cause failure under single load application. For steam generator tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Conclusion

The proposed changes will provide greater assurance of SG tube integrity than that offered by the existing TS. The proposed requirements are performance-based and provide the flexibility to adopt new technology as it matures. These changes are consistent with the guidance in NEI 97-06, "Steam Generator Program Guidelines," (Reference 7.12). Adopting the proposed changes will provide added assurance that SG tubing will remain capable of fulfilling its specific safety function of maintaining RCPB integrity.

4.4 Post-Modification ILRT

The Callaway Plant design incorporates a closed system for transferring steam from the steam generators inside of the primary containment to the main turbine-generator in the turbine building. The inside containment portion of this closed system consists of the outer shell of the steam generators, the main steam lines, the main feedwater lines, the steam generator blowdown and sample lines, and the inner surface of the steam generator tubes. During a design basis LOCA these elements inside containment form a barrier against the uncontrolled release of radioactivity to the environment and thus are considered part of the containment boundary.

The planned replacement of the steam generators affects only the closed piping systems inside containment. The steam generator replacement activities will not affect the containment structure other than cutting the above lines emanating from the original SG shells and re-welding them to the replacement SGs. Access for the RSG modification will be through the equipment hatch. 10 CFR 50, Appendix J, Option B requires integrated leakage testing (Type A) prior to returning the containment to operation following large scale modifications that affect the containment leakage integrity such as SG replacement.

A Type A test measures the containment's overall integrated leakage rate under conditions representing design basis accident containment pressure and system alignment. The affected area of the containment boundary is classified as ASME Class 2 per Section XI. The pressure boundary of the RSG is constructed in accordance with ASME Section III Class 1. As such, the replacement of the steam generators is subject to the requirements of ASME Sections III and XI. The acceptance criterion for ASME Section III/XI system pressure testing for the base metal and welds is "zero leakage." Since the base metal and welds are not allowed to leak, the ASME Section III/XI pressure test requirements are more stringent than the Type A testing requirements. In addition, the test pressure for the ASME Section III/XI system pressure test will be several times that of a Type A test.

The intent of performing a Type A test is to assure the leak-tight integrity of the area affected by the modification (i.e., the closed system inside containment formed by the outer shell of the steam generators and the main steam lines, feedwater lines, steam generator blowdown and sample lines, and inner surface of the steam generator tubes) does not alter the overall leakage rate of the containment. Although the leak test is in a direction reverse that of a LOCA environment, the leak- tightness of the components, piping, and welds is not dependent on the direction the pressure is applied. Thus, the ASME Section III/XI inspection and testing requirements more than fulfill the intent of the requirements of Appendix J, Option B.

Therefore, Callaway Plant proposes a revision to TS 5.5.16 to provide an exception from the requirements of Appendix J for post-modification integrated leakage rate testing associated with steam generator replacement. The effect of this amendment request would be to eliminate the post-modification containment leakage rate (Type A) testing required after the modification to the containment boundary, specifically associated with the steam generator replacement.

4.5 Balance of Plant Evaluations

A review of systems, structures, and components that could be affected by steam generator replacement activities has been performed. For example, the following systems and analyses were reviewed by SGT, a contractor for the RSG project:

Main Steam Line Differential Pressure;
Containment Cooling and HVAC;
Containment Spray System;
Sump pH verification;
Time to Boil;
Natural Circulation;
Essential Service Water;
Secondary Chemical Addition System;
Secondary Sample System;
Steam Generator Blowdown System;
High Energy Line Breaks at Callaway; and
Callaway RSG Radiological Consequences.

The above areas, as well as other plant calculations and documents, were evaluated for the RSG conditions. Any changes needed to support systems can be accomplished without a Technical Specification change or prior NRC approval.

5.0 REGULATORY SAFETY ANALYSIS

This section addresses the standards of 10CFR50.92 as well as the applicable regulatory requirements and acceptance criteria.

5.1 NO SIGNIFICANT HAZARDS CONSIDERATION (NSHC)

The proposed amendment would revise the following Technical Specifications (TS) in support of replacement steam generators to be installed during Refuel 14 (fall 2005):

- 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 Flow 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) Tube Surveillance Program";
- TS 5.5.16, "Containment Leakage Rate Testing Program"; and
- TS 5.6.10, "Steam Generator Tube Inspection Report."

In addition, the proposed amendment would add new TS 3.4.17, "Steam Generator Tube Integrity," pursuant to Technical Specification Task Force (TSTF) Improved Standard Technical Specifications Change Traveler TSTF-449 Revision 2.

The proposed changes do not involve a significant hazards consideration for Callaway Plant based on the three standards set forth in 10CFR50.92(c) as discussed below:

(1) Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

Nuclear Steam Supply System Evaluations for Replacement Steam Generators

As discussed in the NSSS Licensing Report (Appendix A to this amendment application), all acceptance criteria continue to be met. All major NSSS components (e.g., Reactor Vessel, Pressurizer, RCPs, Steam Generators, etc.) have been assessed with respect to bounding conditions expected for replacement steam generator (RSG) conditions. In all cases operation has been found to be acceptable. Major systems and subsystems (e.g., safety injection, RHR, etc.) have been reviewed and acceptable performance has been verified for their normal operation and, as applicable, for their safety-related functions. All reactor trip and ESFAS actuation setpoints have been assessed, and the proposed setpoint modifications will assure adequate protection is afforded for all design basis events.

The reactor core safety limits have been revised based on the RSG project parameters. All of the acceptance criteria for the accident analyses (e.g., DNBR limits, fuel centerline temperatures, etc.) continue to be met with the revised safety limit lines. Therefore, the revised core safety limit line changes are acceptable. The proposed changes to the reactor core safety limits will not initiate any accidents; therefore, they do not increase the probability of an accident previously evaluated in the FSAR. The comprehensive analytical efforts performed to support the proposed RSG conditions include a reanalysis or evaluation of all accident analyses that are impacted by the revised reactor core safety limits.

The changes in various SG-related RTS and ESFAS Allowable Values have resulted from the analyses performed to support plant operation at the proposed RSG conditions. Setpoint uncertainty calculations confirm the acceptability of these revised Allowable Values. The affected RTS and ESFAS Allowable Values have been modified to reflect the results of updated setpoint calculations based on plant-specific uncertainties, calibration practices, calibration equipment, and installed hardware and procedures. The Allowable Values were calculated using the same Westinghouse setpoint methodology used for the current trip setpoints, but improved in a conservative fashion to include refinements that better reflect plant calibration practices and equipment performance. These refinements include the incorporation of a sensor reference accuracy term to address repeatability effects when performing a single pass calibration (i.e., one up and one down pass at several points verifies linearity and hysteresis, but not repeatability). In addition, sensor and rack error terms for calibration accuracy and drift are grouped in the Channel Statistical Allowance equation with their dependent measurement and test equipment (M&TE) terms, then combined with the other independent error terms using the square root sum of the squares (SRSS) methodology. This improved setpoint methodology has been previously review and approved by the NRC. The proposed RTS and ESFAS Allowable Value changes will not initiate any accidents; therefore, they do not increase the probability of an accident previously evaluated in the FSAR. The comprehensive analytical effort performed to support the proposed RSG conditions included a reanalysis or evaluation of all accident analyses that are impacted by the revised RTS and ESFAS Allowable Values. All systems will function as designed.

The decrease in the Maximum Allowable Power for 3 OPERABLE MSSVs per SG from $\leq$ 49% of Rated Thermal Power to $\leq$ 45% of Rated Thermal Power resulted from the analyses and evaluations performed to support plant operation at the proposed RSG conditions. The accident analysis acceptance criteria continue to be met with these changes. These proposed plant system changes do not increase the probability of an accident previously evaluated in the FSAR. The comprehensive analytical effort performed to support the proposed RSG conditions has included a review and evaluation of all components and systems (including interface systems and control systems) that could be affected by this change. All systems will function as designed. The change in the manner in which the Reactor Coolant Flow - Low Allowable Value is defined (while retaining the same numerical value), the change in the manner in which RCS average temperature is defined and the reduced upper limit for nominal T-avg at full power conditions in the Overtemperature ΔT and Overpower ΔT setpoint equations, and the changes to the pressurizer pressure and RCS average temperature limits in the DNB LCO 3.4.1 have also been evaluated. None of these proposed changes will initiate any accidents; therefore, the probability of an accident has not been increased.

The potential dose consequences have been analyzed with respect to the above changes collectively. The dose increases are less than minimal (i.e., <10% of the margin between the regulatory limits and the currently reported doses). The applicable dose acceptance criteria continue to be met.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

Trip Time Delay Elimination

This design change will eliminate only the Trip Time Delay portion of the SG Water Level Low-Low trip functions and return that portion of the design to condition that existed prior to Callaway Amendment 43 dated April 14, 1989. The coincidence logic in the Solid State Protection System will be unaffected. In all other regards, the design of the RTS and ESFAS instrumentation will be unaffected. These protection systems will continue to function in a manner consistent with the plant design basis. All design, material, and construction standards that were applicable prior to this amendment request are maintained.

The probability and consequences of accidents previously evaluated in the FSAR are not adversely affected because the removal of the trip time delay circuitry assures a faster response by the affected trip functions, consistent with the safety analysis acceptance criteria and the original plant licensing basis.

The proposed change will not affect the probability of any event initiators. There will be no degradation in the performance of, or an increase in the number of challenges imposed on, safety-related equipment assumed to function during an accident situation. There will be no change to normal plant operating parameters or accident mitigation performance.

The proposed change will not alter any assumptions or change any mitigation actions in the radiological consequence evaluations in the FSAR.

Therefore, the proposed TTD elimination does not involve a significant increase in the probability or consequences of an accident previously evaluated.

TSTF-449 Generic Licensing Change Package

This proposed change requires a Steam Generator Program that includes performance criteria that will provide reasonable assurance that the steam generator (SG) tubing will retain integrity over the full range of operating conditions (including startup, operation in the power range, hot standby, cooldown, and all anticipated transients included in the design specification). The SG performance criteria are based on tube structural integrity, accident induced leakage, and operational LEAKAGE.

A steam generator tube rupture (SGTR) event is one of the design basis accidents that are analyzed as part of a plant's licensing basis. In the analysis cases for the SGTR event at Callaway Plant, a primary to secondary LEAKAGE rate of 1 gallon per minute (gpm) to the unaffected SGs is assumed, in excess of the RCS Operational LEAKAGE rate limit in TS 3.4.13, and the LEAKAGE rate associated with a double-ended rupture of a single tube in the ruptured SG is also assumed. For other design basis accidents such as main steam line break (MSLB), rod ejection, and reactor coolant pump locked rotor, the SG tubes are assumed to retain their structural integrity (i.e., they are assumed not to rupture). These additional analyses for Callaway Plant assume, as an initial condition, that primary to secondary LEAKAGE for all SGs is 1 gpm. The accident induced leakage criterion introduced by the proposed change to TS 5.5.9 accounts for tubes that may leak during design basis accidents. The accident induced leakage criterion limits this leakage to no more than the 1 gpm value assumed in the accident analyses.

The SG performance criteria added to TS 5.5.9 identify the standards against which tube integrity is to be measured. Meeting the performance criteria provides reasonable assurance that the SG tubing will remain capable of fulfilling its specific safety function of maintaining reactor coolant pressure boundary integrity throughout each operating cycle and in the unlikely event of a design basis accident. The performance criteria are only a part of the Steam Generator Program required by the proposed change to TS 5.5.9. The program, defined by NEI 97-06, Steam Generator Program Guidelines, includes a framework that incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring.

The consequences of design basis accidents are, in part, functions of the DOSE EQUIVALENT I-131 in the primary coolant and the primary to secondary LEAKAGE rates resulting from an accident. Therefore, limits are included in TS 3.4.13 for RCS Operational leakage and in TS 3.4.16 for DOSE EQUIVALENT I-131 in the primary coolant to ensure the plant is operated within its analyzed condition. The radiological consequence analyses at Callaway Plant assume that the primary to secondary LEAKAGE rate is 1 gpm (more conservative than the limit in TS 3.4.13), and that the reactor coolant activity levels of DOSE EQUIVALENT I-131 are at the TS 3.4.16 limits.

The proposed TSTF-449 changes reflect the design of the replacement SGs, but do not affect their method of operation or primary or secondary coolant chemistry controls. The proposed changes update the TS and enhance the requirements for SG inspections. The proposed changes do not adversely impact the conclusions of any previously evaluated design basis accident and are an improvement over the existing TS.

Therefore, this proposed change to implement TSTF-449 does not affect the consequences of a SGTR accident and the probability of such an accident is reduced. In addition, this proposed change does not affect the consequences of an MSLB, rod ejection, reactor coolant pump locked rotor, or any other accident event involving the potential release of radioactive fluids from the secondary side of Callaway Plant.

Post-Modification ILRT Exception

This proposed change would provide Callaway Plant with an exception from performing a post-modification containment integrated leak rate test following the replacement of the steam generators during Refuel 14. Integrated leak rate tests are performed to assure the leak-tightness of the primary containment boundary system, and as such they are not accident initiators. Therefore, not performing an integrated leak rate test will not affect the probability of an accident previously evaluated. The intent of post-modification integrated leak rate testing requirements is to assure the leak-tight integrity of the area affected by the modification. For the Callaway Plant steam generator replacement modification, this intent will be satisfied by performing the American Society of Mechanical Engineers code required inspections and tests. Since the leak-tightness integrity of the primary containment boundary affected by the steam generator replacement will be assured, there is no change in the containment boundary's ability to confine radioactive materials during an accident. Therefore, adding a Technical Specification exception from the steam generator replacement post-modification integrated leak rate testing requirements does not involve a significant increase in the probability or consequences of an accident previously evaluated.

(2) **Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?**

Response: No

<u>Nuclear Steam Supply System Evaluations for Replacement Steam Generators</u>

No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced as a result of this amendment. There will be no adverse effect or challenges imposed on any safety-related system as a result of this amendment.

This amendment does not alter the safe performance of the plant protection systems to trip the reactor when necessary or actuate ESF systems.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

<u>Trip Time Delay Elimination</u>

No new accident scenarios, transient precursors, failure mechanisms, or limiting single failures are introduced as a result of this amendment. There will be no adverse effect or challenges imposed on any safety-related system as a result of this amendment.

This amendment does not alter the safe performance of the plant protection systems to trip the reactor when necessary or actuate ESF systems.

Therefore, this proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

TSTF-449 Generic Licensing Change Package

The proposed performance based requirements are an improvement over the requirements imposed by the existing TS.

Implementation of the proposed Steam Generator Program will not introduce any adverse changes to the plant design basis or postulated accidents resulting from potential tube degradation. The result of the implementation of the Steam Generator Program will be an enhancement of SG tube performance. Primary to secondary LEAKAGE that may be experienced during all plant conditions will be monitored to ensure it remains within current accident analysis assumptions.

This proposed change does not impact the method of SG operation or primary or secondary coolant chemistry controls. In addition, this proposed change does not impact any other plant system or component. The change enhances SG inspection requirements.

Therefore, this proposed change does not create the possibility of a new or different type of accident from any accident previously evaluated.

Post-Modification ILRT Exception

The proposed change would provide Callaway Plant with an exception from performing a post-modification containment integrated leak rate test following the replacement of the steam generators during Refuel 14. Providing an exception from performing a test does not involve a physical change to the plant nor does it change the operation of the plant. Thus it cannot introduce a new failure mode. Therefore adding a Technical Specification requirement that provides an exception from the steam generator replacement post-modification integrated leak rate testing requirement does not create the possibility of a new or different kind of accident from any previously evaluated.

(3) Do the proposed changes involve a significant reduction in a margin of safety?

Response: No

Nuclear Steam Supply System Evaluations for Replacement Steam Generators

The analyses and evaluations supporting the proposed RSG conditions reflect the reactor core safety limits. All acceptance criteria continue to be met.

The analyses supporting the proposed RSG conditions reflect the proposed RTS and ESFAS Allowable Values. Setpoint calculations demonstrate that margin exists between these Allowable Values and the corresponding safety analysis limits used in the RSG analyses. The calculations are based on plant instrumentation and calibration/functional test methods and include allowances for the RSG conditions. All analyses and evaluations supporting the proposed RSG core safety limits, decrease in maximum allowable power level for 3 operable MSSVs per SG, the change in the manner in which the Reactor Coolant Flow - Low Allowable Value is defined (while retaining the same numerical value), the change in the manner in which RCS average temperature is defined and the reduced upper limit for nominal T-avg at full power conditions in the Overtemperature ΔT and Overpower ΔT setpoint equations, and the changes to the pressurizer pressure and RCS average temperature limits in the DNB LCO 3.4.1 are acceptable. All acceptance criteria continue to be met. Therefore, the proposed changes do not involve a significant reduction in the margin of safety.

Trip Time Delay Elimination

This proposed change does not eliminate any RTS or ESFAS surveillances or alter the frequency of those surveillances as required by the TS. The SG Water Level Low-Low safety analysis limit of 0% span assumed in the analyses supporting the approval of the TTD design in Callaway Amendment 43 dated April 14, 1989 is also used in the RSG analyses discussed above. None of the acceptance criteria for any accident analysis is changed for TTD elimination.

There will be no effect on the manner in which safety limits or limiting safety system settings are determined nor will there be any effect on those plant systems necessary to assure the accomplishment of protection functions. The radiological dose consequence acceptance criteria will continue to be met.

Therefore, the proposed change does not involve a significant reduction in a margin of safety.

TSTF-449 Generic Licensing Change Package

The SG tubes in pressurized water reactors are an integral part of the reactor coolant pressure boundary and, as such, are relied upon to maintain the primary system's pressure and inventory. As part of the reactor coolant pressure boundary, 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. In addition, the SG tubes also isolate the radioactive fission products in the primary coolant from the secondary system. In summary, the safety function of a SG is maintained by ensuring the integrity of its tubes.

Steam generator tube integrity is a function of the design, environment, and the physical condition of the tube. This proposed change to implement TSTF-449 does not, of itself, affect tube design or operating environment. The proposed change is expected to result in an improvement in the tube integrity by implementing the Steam Generator Program to manage SG tube inspection, assessment, repair (only under NRC-approved methods, none of which currently apply to the RSGs), and plugging. The requirements established

by the Steam Generator Program are consistent with those in the applicable design codes and standards and are an improvement over the requirements in the existing TS.
For the above reasons, the margin of safety is not changed and overall plant safety will be enhanced by this proposed change.

Post-Modification ILRT Exception

The proposed change would provide Callaway Plant with an exception from performing a post-modification containment integrated leak rate test following the replacement of the steam generators during Refuel 14. The intent of post-modification integrated leak rate testing requirements is to assure the leak-tight integrity of the area affected by the modification. This intent will be satisfied by performing American Society of Mechanical Engineers code required inspections and tests. The acceptance criterion for American Society of Mechanical Engineers code system pressure testing for the base metal and welds is no leakage. In addition, the test pressure for the system pressure test will be several times that required during an integrated leak rate test. Since the leak-tight integrity of the primary containment boundary affected by the steam generator replacement will be assured, there is no change in the primary containment boundary's ability to confine radioactive materials during an accident. Therefore, adding a Technical Specification requirement that provides an exception from the steam generator replacement post-modification integrated leak rate testing requirements does not involve a significant reduction in a margin of safety.

Conclusion:

Based on the above, AmerenUE concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 APPLICABLE REGULATORY REQUIREMENTS/CRITERIA

The regulatory bases and guidance documents associated with the systems discussed in this amendment application include:

- 10 CFR 50.55a, Codes and Standards - Section (c) *Reactor coolant pressure boundary.* (1) Components which are part of the reactor coolant pressure boundary must meet the requirements for Class 1 components in Section III of the ASME Boiler and Pressure Vessel Code, except as provided in paragraphs (c)(2), (c)(3), and (c)(4) of this section.

  The proposed TSTF-449 changes and the Steam Generator Program requirements which underlie it are in full compliance with the ASME Code. The proposed TSTF-449 TS changes are more effective at ensuring tube integrity and, therefore, compliance with the ASME Code, than the existing TS as described in Section 4.0 above (Technical Analysis).

- GDC-13 requires that instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems.

- GDC-14 requires that the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

- GDC-15 requires that the reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

- GDC-20 requires that the protection system(s) shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

- GDC-21 requires that the protection system(s) shall be designed for high functional reliability and testability.

- GDC-22 through GDC-25 and GDC-29 require various design attributes for the protection system(s), including independence, safe failure modes, separation from control systems, requirements for reactivity control malfunctions, and protection against anticipated operational occurrences.

- GDC-30 requires that components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

- GDC-32 requires that components which are part of the reactor coolant pressure boundary shall be designed to permit periodic inspection and testing of important areas and features to assess their structural and leaktight integrity.

- 10CFR50.55a(h) requires that the protection systems meet IEEE 279-1971. Section 4.1 of IEEE 279-1971 discusses the general functional requirement for protection systems that they automatically initiate appropriate protective action whenever a condition monitored by the system reaches a preset level, i.e., the nominal Trip Setpoint.

- NRC Regulatory Guide (RG) 1.105 discusses accepted practices for the treatment of instrument setpoints. Callaway's compliance with RG 1.105 is described in FSAR Appendix 3A.

There are no changes being proposed such that compliance with any of the regulatory requirements and commitments above would come into question. The evaluations documented above and attached hereto confirm that Callaway Plant will continue to comply with all applicable regulatory requirements.

In conclusion, based on the considerations discussed above, (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) issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

AmerenUE has determined that the proposed amendment would change requirements with respect to the installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. However, AmerenUE has evaluated the proposed amendment and has determined that the amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amount of effluent that may be released offsite, or (iii) a significant increase in the individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10CFR51.22 (c)(9). Therefore, pursuant to 10CFR51.22 (b), an environmental assessment of the proposed amendment is not required.

7.0 REFERENCES

7.1 Technical Specification Task Force (TSTF) Improved Standard Technical Specifications Change Traveler TSTF-449, Revision 2, "SG Tube Integrity."

7.2 ULNRC-04592 dated June 27, 2003 and ULNRC-04928 dated December 12, 2003.

7.3 Callaway License Amendment Number 159 dated March 11, 2004.

7.4 WCAP-11325-P-A, Revision 1, "WOG Trip Reduction and Assessment Program: Steam Generator Low Water Level Protection System Modifications to Reduce Feedwater-Related Trips," February 1988.

7.5 WCAP-11883-P, Implementation of the Steam Generator Low Low Level Reactor Trip Time Delay and Environmental Allowance Modifier in the Callaway Plant," August 1988.

7.6 EPRI TR-107569, "Steam Generator Examination Guideline."

7.7 EPRI TR-107621, "Steam Generator Integrity Assessment Guideline."

7.8 EPRI TR-107620, "Steam Generator In-situ Pressure Test Guideline."

7.9 EPRI TR-104788, "PWR Primary-to-Secondary Leak Guideline."

7.10 EPRI TR-105714, "Primary Water Chemistry Guideline."

7.11 EPRI TR-102134, "Secondary Water Chemistry Guideline."

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

7.13 NRC RG 1.163, Revision 0, "Performance-Based Containment Leak-Test Program," September 1995.

7.14 NEI 94-01, Revision 0, "Industry Guideline for Implementing Performance-Based Option of 10 CFR 50, Appendix J," July 1995.

7.15 Calvert Cliffs Nuclear Power Plant, Unit No. 2, Amendment Number 230 dated June 27, 2002.

7.16 EPRI Report R-5515-00-2, "Experience of US and Foreign PWR Steam Generators with Alloy 600TT and Alloy 690TT Tubes and Sleeves," 6/5/02.

7.17 S. C. Collins memo to W. D. Travers, "Steam Generator Action Plan Revision to Address Differing Professional Opinion on Steam Generator Tube Integrity," May 11, 2001.

7.18 Generic Letter 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995.

7.19 Testimony of James Knight Before the Atomic Safety and Licensing Board, Docket Nos. 50-282 and 50-306, January 1975.

7.20 Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976.

7.21 ASME B&PV Code, Section III, Rules for Construction of Nuclear Facility Components.

ATTACHMENT 2

MARKUP OF TECHNICAL SPECIFICATIONS

Replace with revised figure

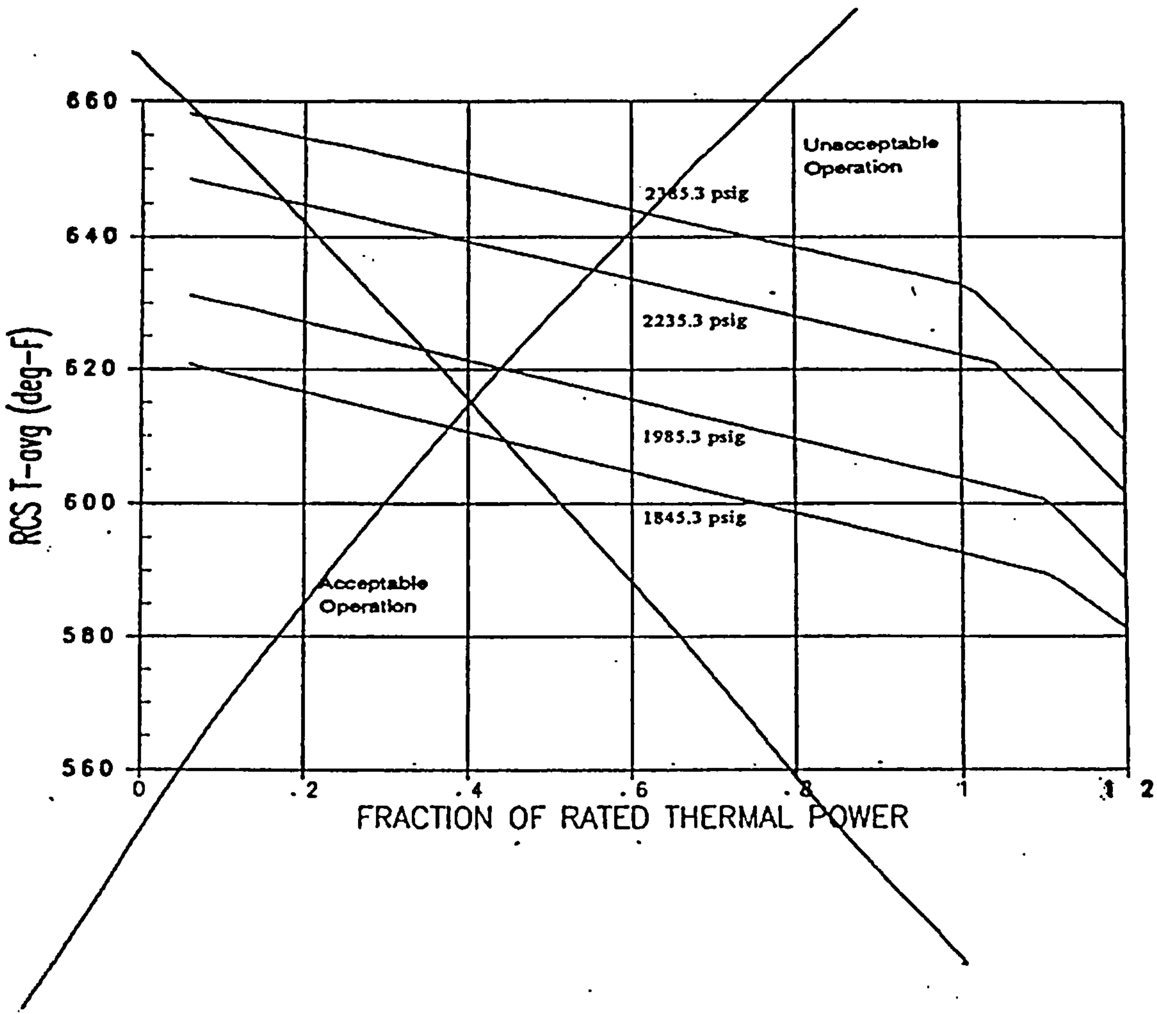

Figure 2.1.1-1 (page 1 of 1)
Reactor Core Safety Limits

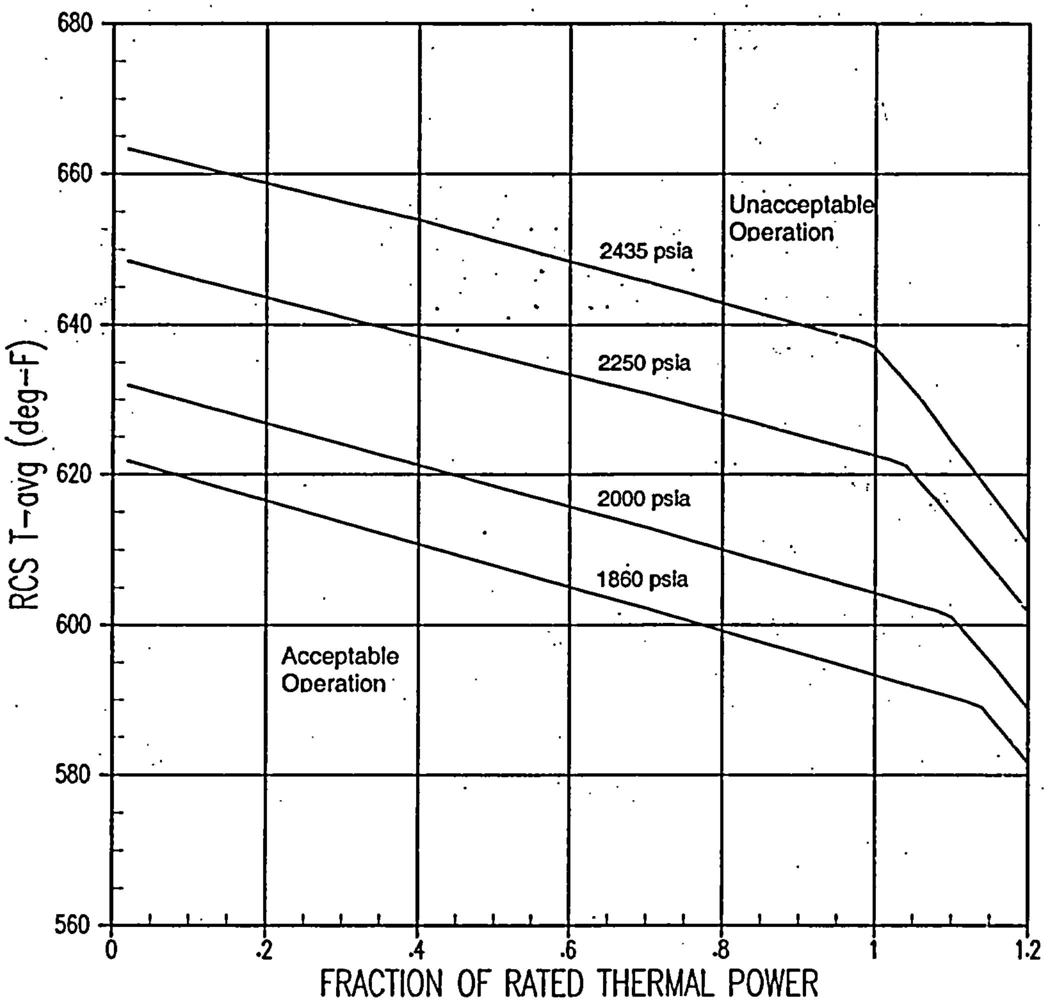

Figure 2.1.1-1 (page 1 of 1)
Reactor Core Safety Limits

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
W. ~~One or more Vessel ΔT Equivalent channel(s) inoperable.~~ Not used.	~~W.1~~	~~Place channel(s) in trip.~~	~~6 hours~~
	~~OR~~		
	~~W.2~~	~~Be in MODE 3.~~	~~12 hours~~
X. One or more Containment Pressure - Environmental Allowance Modifier channel(s) inoperable.	X.1	Place channel(s) in trip.	6 hours
	OR		
	X.2	Be in MODE 3.	12 hours

Table 3.3.1-1 (page 3 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
9.	Pressurizer Water Level - High	1[g]	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 93.8% of instrument span
10.	Reactor Coolant Flow - Low	1[g]	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.8% ~~(m)~~ of indicated loop flow
	Not Used					
	Undervoltage RCPs	1[g]	2/bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 10105 Vac
	Underfrequency RCPs	1[g]	2/bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.1 Hz
14	Steam Generator (SG) Water Level Low-Low[l]					
	a. Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ ~~25.3%~~ 20.6% of Narrow Range Instrument Span
	b. Steam Generator Water Level Low-Low (Normal Containment Environment)	1[p], 2[p]	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ ~~10.6%~~ 16.6% of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(m) ~~% of loop minimum measured flow (MMF = 95,660 gpm).~~ Not used.
(p) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
14. Steam Generator (SG) Water Level Low-Low[l] (continued)					
c. ~~Vessel ΔT Equivalent including delay timers Trip Time Delay~~ Not used					
~~(1) Vessel ΔT (Power-1)~~	~~1,2~~	~~4~~	~~W~~	~~SR 3.3.1.1~~ ~~SR 3.3.1.7~~ ~~SR 3.3.1.10~~ ~~SR 3.3.1.16~~	~~≤ Vessel ΔT Equivalent to 13.9% RTP[n]~~
~~(2) Vessel ΔT (Power-2)~~	~~1,2~~	~~4~~	~~W~~	~~SR 3.3.1.1~~ ~~SR 3.3.1.7~~ ~~SR 3.3.1.10~~ ~~SR 3.3.1.16~~	~~≤ Vessel ΔT Equivalent to 23.9% RTP[o]~~
d. Containment Pressure - Environmental Allowance Modifier	1,2	4	X	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 2.0 psig
15. Not Used					

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(n) ~~With a time delay ≤ 240 seconds.~~ Not used.
(o) ~~With a time delay ≤ 150 seconds.~~ Not used.

Table 3.3.1-1 (page 7 of 8)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following setpoint by more than 1.23% of ΔT span (1.85% RTP).

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left(\frac{1}{1+\tau_3 s}\right) \leq \Delta T_0 \left\{ K_1 - K_2 \left[\frac{(1+\tau_4 s)}{(1+\tau_5 s)} T \frac{1}{(1+\tau_6 s)} - T' \right] + K_3(P - P') - f_1(\Delta I) \right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the ~~referenced T_{avg} at RTP, ≤ 588.4°F.~~ nominal T_{avg} at RTP, ≤ 585.3°F.

P is the measured pressurizer pressure, psig.
P' is the nominal RCS operating pressure = 2235 psig.

$K_1 = 1.1950$	$K_2 = 0.0251/°F$	$K_3 = 0.00116/psig$
$\tau_1 \geq 8$ sec	$\tau_2 \leq 3$ sec	$\tau_3 = 0$ sec
$\tau_4 \geq 28$ sec	$\tau_5 \leq 4$ sec	$\tau_6 = 0$ sec

$f_1(\Delta I) =$	$-0.0325\{21\% + (q_t - q_b)\}$	when $q_t - q_b < -21\%$ RTP
	0% of RTP	when -21% RTP $\leq q_t - q_b \leq 8\%$ RTP
	$0.02973\{(q_t - q_b) - 8\%\}$	when $q_t - q_b > 8\%$ RTP

where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

Table 3.3.1-1 (page 8 of 8)
Reactor Trip System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following setpoint by more than 1.21% of ΔT span (1.82% RTP).

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left(\frac{1}{1+\tau_3 s}\right) \le \Delta T_0 \left\{ K_4 - K_5 \frac{(\tau_7 s)}{(1+\tau_7 s)}\left(\frac{1}{1+\tau_6 s}\right) T - K_6 \left[T \frac{1}{(1+\tau_6 s)} - T'' \right] - f_2(\Delta I) \right\}$$

Where:

ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T" is the ~~indicated T_{avg} at RTP (Calibration temperature for ΔT instrumentation), ≤ 588.4°F.~~
nominal T_{avg} at RTP, ≤ 585.3°F.

$K_4 = 1.1073$

$K_5 = 0.02$/°F for increasing T_{avg}
0/°F for decreasing T_{avg}

$K_6 = 0.0015$/°F when T > T"
0/°F when T ≤ T"

$\tau_1 \ge 8$ sec
$\tau_2 \le 3$ sec
$\tau_3 = 0$ sec
$\tau_6 = 0$ sec
$\tau_7 \ge 10$ sec

$f_2(\Delta I)$ = 0% RTP for all ΔI.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
M. ~~One or more Vessel ΔT Equivalent channel(s) inoperable.~~ Not used.	~~M.1~~	~~Place channel(s) in trip.~~	~~6 hours~~
	~~OR~~		
	~~M.2~~	~~Be in MODE 3.~~	~~12 hours~~
N. One or more Containment Pressure - Environmental Allowance Modifier channel(s) inoperable.	N.1	Place channel(s) in trip.	6 hours
	OR		
	N.2.1	Be in MODE 3.	12 hours
	AND		
	N.2.2	Be in MODE 4.	18 hours
O. One channel inoperable.	----------NOTE---------- LCO 3.0.4 is not applicable.		
	O.1	Place channel in trip.	1 hour
	AND		
	O.2	Restore channel to OPERABLE status.	During performance of the next required COT

(continued)

Table 3.3.2-1 (page 1 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
Safety Injection					
Manual Initiation	1,2,3,4	2	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6 SR 3.3.2.13	NA
c. Containment Pressure - High 1	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 4.5 psig
d. Pressurizer Pressure - Low	1,2,3[b]	4	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 1834 psig
e. Steam Line Pressure - Low	1,2,3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ ~~571~~ 609 psig[c]
2. Containment Spray					
a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure High - 3	1,2,3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 28.3 psig

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) Interlock and below P-11 unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds.

Table 3.3.2-1 (page 3 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
4. Steam Line Isolation					
Manual Initiation	1,2[i], 3[i]	2	F	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2[i], 3[i]	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Automatic Actuation Logic and Actuation Relays (MSFIS)	2[i],3[i]	2 trains[o]	G	SR 3.3.2.2	NA
d. Containment Pressure - High 2	1,2[i], 3[i]	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 18.3 psig
e. Steam Line Pressure					
(1) Low	1,2[i], 3[b][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ ~~571~~ psig[c] 609
(2) Negative Rate - High	3[g][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 124 psi[h]

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) Interlock and below P-11 unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds.
(g) Below the P-11 (Pressurizer Pressure) Interlock; however, may be blocked below P-11 when safety injection on low steam line pressure is not blocked.
(h) Time constant utilized in the rate/lag controller is ≥ 50 seconds.
(i) Except when all MSIVs are closed.
(o) Each train requires a minimum of two programmable logic controllers to be OPERABLE.

Table 3.3.2-1 (page 4 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2(j), 3(j)	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6 SR 3.3.2.14	NA
b. Automatic Actuation Logic and Actuation Relays (MSFIS)	1, 2(j), 3(j)	2 trains(o)	G	SR 3.3.2.2	NA
c. SG Water Level - High High (P-14)	1,2(j)	4 per SG		SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ ~~70.0%~~ 91.4% of Narrow Range Instrument Span
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Steam Generator Water Level Low-Low(q)					
(1) Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2(j), 3(j)	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ ~~25.2%~~ 20.6% of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs are closed.
(o) Each train requires a minimum of two programmable logic controllers to be OPERABLE.
(q) Feedwater isolation only.

Table 3.3.2-1 (page 5 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Turbine Trip and Feedwater Isolation					
e. Steam Generator Water Level Low-Low[q] (continued)					
(2) Steam Generator Water Level Low-Low (Normal Containment Environment)	1[r], 2[j,r], 3[j,r]	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ ~~40.0%~~ 16.6% of Narrow Range Instrument Span
(3) ~~Vessel ΔT Equivalent including delay timers - Trip Time Delay~~ Not used					
~~(a) Vessel ΔT (Power-1)~~	~~1, 2[j]~~	~~4~~	~~M~~	~~SR 3.3.2.1~~ ~~SR 3.3.2.5~~ ~~SR 3.3.2.9~~ ~~SR 3.3.2.10~~	~~≤ Vessel ΔT Equivalent to 15.9% RTP[k]~~
~~(b) Vessel ΔT (Power-2)~~	~~1, 2[j]~~	~~4~~	~~M~~	~~SR 3.3.2.1~~ ~~SR 3.3.2.5~~ ~~SR 3.3.2.9~~ ~~SR 3.3.2.10~~	~~≤ Vessel ΔT Equivalent to 25.9% RTP[l]~~
(4) Containment Pressure - Environmental Allowance Modifier	2[j], 3[j]	4	N	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 2.0 psig

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs are closed.
(k) ~~With a time delay ≤ 240 seconds.~~ Not used.
(l) ~~With a time delay ≤ 120 seconds.~~ Not used.
(q) Feedwater isolation only.
(r) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[(a)]
6. Auxiliary Feedwater					
a. Manual Initiation	1, 2, 3	1/pump	P	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	1,2,3	2 trains	Q	SR 3.3.2.3	NA
d. SG Water Level Low-Low					
(1) Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	20.6% ≥ ~~25.2%~~ of Narrow Range Instrument Span
(2) Steam Generator Water Level Low-Low (Normal Containment Environment)	1[(r)], 2[(r)], 3[(r)]	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	16.6% ≥ ~~18.8%~~ of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(r) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.2-1 (page 7 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
6. Auxiliary Feedwater					
d. SG Water Level Low-Low (continued)					
(3) ~~Vessel ΔT Equivalent including delay timers—Trip Time Delay~~ Not used					
~~(a) Vessel ΔT (Power-1)~~	~~1,2~~	~~4~~	~~M~~	~~SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10~~	~~≤ Vessel ΔT Equivalent to 15.9% RTP(k)~~
~~(b) Vessel ΔT (Power-2)~~	~~1,2~~	~~4~~	~~M~~	~~SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10~~	~~≤ Vessel ΔT Equivalent to 23.9% RTP(l)~~
(4) Containment Pressure - Environmental Allowance Modifier	1, 2, 3	4	N	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 2.0 psig
e. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
Loss of Offsite Power	1,2,3	2 trains	R	SR 3.3.2.7 SR 3.3.2.10	NA
g. Trip of all Main Feedwater Pumps	1,2(n)	2 per pump	J	SR 3.3.2.8	NA

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(k) ~~With a time delay ≤ 240 seconds.~~ Not used.
(l) ~~With a time delay ≤ 100 seconds.~~ Not used.
(n) Trip function may be blocked just before shutdown of the last operating main feedwater pump and restored just after the first main feedwater pump is put into service following performance of its startup trip test.

3.4 REACTOR COOLANT SYSTEM (RCS)

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

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ ~~2220~~ 2223 psig;

b. RCS average temperature ≤ ~~592.6°F~~ 590.1 °F; and

c. RCS total flow rate ≥ 382,630 gpm.

APPLICABILITY: MODE 1

NOTE

Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ ~~2220~~ 2223 psig.	12 hours
SR 3.4.1.2	Verify RCS average temperature is ≤ ~~592.6°F.~~ 590.1°F.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 382,630 gpm.	12 hours
SR 3.4.1.4	-------------------NOTE------------------- Calculated rather than verified by precision heat balance when performed prior to THERMAL POWER exceeding 75% RTP. --- Verify by precision heat balance that RCS total flow rate is ≥ 382,630 gpm.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP. AND 18 months

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side narrow range water levels are ≥ ~~4%~~ 7% for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required loops inoperable. OR No RCS or RHR loop in operation.	B.1	Suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SDM of LCO 3.1.1.	Immediately
	AND		
	B.2	Initiate action to restore one loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side narrow range water levels are ≥ ~~4%~~ for required RCS loops. ≥ 7%	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops - MODE 5, Loops Filled

LCO 3.4.7

One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side wide range water level of at least two steam generators (SGs) shall be ≥ ~~66%.~~ 86%.

-- NOTES --

1. The RHR pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 275°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side wide range water level is ≥ ~~66%~~ in required SGs. 86%	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

~~d.~~ ~~600 gallons per day total primary to secondary LEAKAGE through all steam generators (SGs); and~~

d. ~~e.~~ 150 gallons per day primary to secondary LEAKAGE through any one SG.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE, or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.13.1	-------------------NOTES------------------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. Verify RCS operational LEAKAGE is within limits by performance of ~~Perform~~ RCS water inventory balance.	72 hours
SR 3.4.13.2	~~Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.~~ INSERT SR 3.4.13.2	~~In accordance with the Steam Generator Tube Surveillance Program~~ 72 hours

INSERT SR 3.4.13.2

------------------------NOTE------------------------
Not required to be performed until 12 hours after establishment of steady state operation.

Verify primary to secondary LEAKAGE is $\leq$ 150 gallons per day through any one SG.

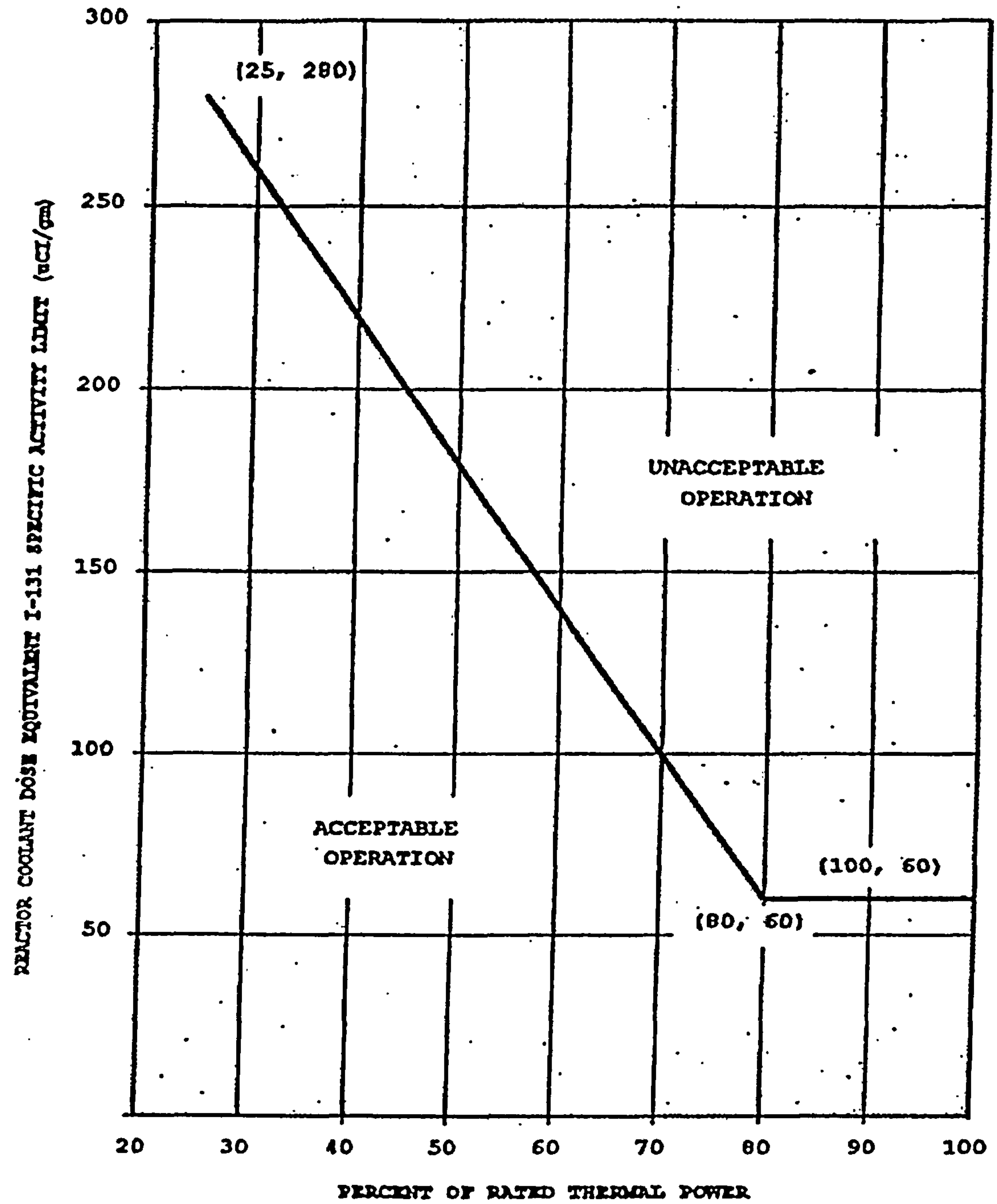

Figure 3.4.16-1 (page 1 of 1)
Reactor Coolant DOSE EQUIVALENT I-131 Specific Activity
Limit Versus Percent of RATED THERMAL POWE

→ INSERT NEW LCO 3.4.17 (next 2 pages)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

<u>AND</u>

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

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

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1	Verify tube integrity of the affected tube(s) is maintained until the next inspection.	7 days
	<u>AND</u>		
	A.2	Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

**Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power**

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ 85
3	≤ ~~49~~ 45
2	≤ 27

5.5 Programs and Manuals (continued)

Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

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

~~The tube integrity of each steam generator shall be demonstrated by performance of the following augmented inservice inspection program.~~

~~The provisions of SR 3.0.2 are applicable to the SG Tube Surveillance Program test frequencies.~~

INSERT 5.5.9

(continued)

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

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during 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.

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

   1. Structural integrity performance criterion: All inservice steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 ($3\Delta P$) against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

   2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm total for all four steam generators.

   3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

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

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

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

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

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

a. Steam Generator Sample Selection and Inspection - Each steam generator's tube integrity shall be determined during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 5.5.9-1.

b. Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Tables 5.5.9-2 and 5.5.9-3. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 5.5.9.c and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 5.5.9.d. When applying the exceptions of Specification 5.5.9.b.1 through 5.5.9.b.3, previous defects or imperfections in the area repaired by sleeving are not considered an area requiring inspection. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators; the tubes selected for these inspections shall be selected on a random basis except:

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

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

   a) All nonplugged tubes that previously had detectable wall penetrations (greater than 20%),

   b) Tubes in those areas where experience has indicated potential problems, and

   c) A tube inspection (pursuant to Specification 5.5.9.d.1.h) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

3. The tubes selected as the second and third samples (if required by Tables 5.5.9-2 and 5.5.9-3) during each inservice inspection may be subjected to a partial tube inspection provided:

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

a) The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found, and

b) The inspections include those portions of the tubes where imperfections were previously found.

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

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective
Note:	In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

c. Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

1. The first inservice inspection shall be performed after 6 Effective Full Power Months but within 24 calendar months of initial criticality. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months;

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

2. If the results of the inservice inspection of a steam generator conducted in accordance with Tables 5.5.9-2 and 5 5 9-3 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 5.5.9.c.1. The interval may then be extended to a maximum of once per 40 months; and

3 Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Tables 5 5.9-2 and 5.5.9-3 during the shutdown subsequent to any of the following conditions:

a) Reactor-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.13; or

b) A seismic occurrence greater than the Operating Basis Earthquake, or

c) A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

d) A main steam line or feedwater line break.

d. Acceptance Criteria

1 As used in this Specification:

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

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

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

c) Degraded Tube means a tube containing imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation;

d) % Degradation means the percentage of the tube or sleeve wall thickness affected or removed by degradation;

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

f) Plugging or Repair Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging or repaired by sleeving and is equal to 40% of the nominal tube wall thickness. The plugging limit for laser welded sleeves is equal to 39% of the nominal sleeve wall thickness The plugging limit for Electrosleeves is equal to 20% of the nominal sleeve wall thickness;

g) Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of a Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 5.5.9.c.3, above;

h) Tube Inspection means an inspection of the steam generator tube from the tube end (hot leg side) completely around the U-bend to the top support of the cold leg. For a tube repaired by sleeving, the tube inspection shall include the sleeved portion of the tube,

i) Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed after the field hydrostatic test and prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections; and

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Tube Surveillance Program (continued)

j) Tube Repair refers to a process that reestablishes tube serviceability. Acceptable tube repairs will be performed by the following processes:

1) Laser welded sleeving as described in Westinghouse Technical Report WCAP-14596-P, "Laser Welded Elevated Tube Sheet Sleeves For Westinghouse Model F Steam Generators." March 1996 (W Proprietary)

2) Electrosleeving as described in Framatome Technical Report BAW - 10219P, Revision 4, 12/00, "Electrosleeving Qualifications for PWR Recirculating Steam Generator Tube Repair" and as supplemented by the information provided by ULNRC-04558, dated November 7, 2001. The plugging or repair limit for the pressure boundary portion of Electrosleeves is determined to be 20% through wall of the nominal sleeve wall thickness (as determined by NDE). The 20% plugging or repair limit will apply to inner diameter pits in Regions B and C, however all sleeves with detected ID flaw indications will be removed from service upon detection.

Electrosleeves will not be installed in the outermost periphery tubes of the steam generator bundles where potentially locked tubes would cause high axial loads.

k) Degraded Sleeve means a sleeve containing imperfections greater than 0% but less than 20% of the nominal wall thickness caused by degradation.

2. The steam generator status shall be determined after completing the corresponding actions (plug or repair by sleeving all tubes exceeding the plugging or repair limit and all tubes containing through-wall cracks) required by Tables 5.5.9-2 and 5.5.9-3.

Reports

The contents and frequency of reports concerning the steam generator tube surveillance program shall be in accordance with Specification 5.6.10.

(continued)

5.5 Programs and Manuals (continued)

TABLE 5.5.9-1

MINIMUM NUMBER OF STEAM GENERATORS TO BE

INSPECTED DURING INSERVICE INSPECTION

Preservice Inspection	No			Yes		
No. of Steam Generators per Unit	Two	Three	Four	Two	Three	Four
First Inservice Inspection	All			One	Two	Two
Second & Subsequent Inservice Inspections	One[1]			One[1]	One[2]	One[3]

TABLE NOTATIONS

1. The inservice inspection may be limited to one steam generator on a rotating schedule encompassing 3 N % of the tubes (where N is the number of steam generators in the plant) if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Note that under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances the sample sequence shall be modified to inspect the most severe conditions.

2. The other steam generator not inspected during the first inservice inspection shall be inspected. The third and subsequent inspections should follow the instructions described in 1 above.

3. Each of the other two steam generators not inspected during the first inservice inspections shall be inspected during the second and third inspections. The fourth and subsequent inspections shall follow the instructions described in 1 above.

(continued)

5.5 Programs and Manuals (continued)

TABLE 5.5.9-2

STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S.G.	C-1	None	N.A.	N.A.	N.A.	N.A.
	C-2	Plug or repair defective tubes and inspect additional 2S tubes in this S.G.	C-1	None	N.A.	N.A.
			C-2	Plug or repair defective tubes and inspect additional 4S tubes in this S.G.	C-1	None
					C-2	Plug or repair defective tubes
					C-3	Perform action for C-3 result of first sample
			C-3	Perform action for C-3 result of first sample	N.A	N.A.
	C-3	Inspect all tubes in this S.G., plug or repair defective tubes and inspect 2S tubes in each other S.G. Notification to NRC pursuant to §50.72(b)(2) of 10 CFR Part 50	All other S.G.s are C-1	None	N.A.	N.A.
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of second sample	N.A.	N.A.

(continued)

5.5 Programs and Manuals

TABLE 5.5.9-2

STEAM GENERATOR TUBE INSPECTION
(continued)

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
			Additional S.G. is C-3	Inspect all tubes in each S.G. and plug or repair defective tubes. Notification to NRC pursuant to §50.72(b)(2) of 10 CFR Part 50	N.A.	N.A.

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

(continued)

5.5 Programs and Manuals (continued)

TABLE 5.5.9-3

STEAM GENERATOR REPAIRED TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required
A minimum of 20% of repaired tubes (1) (2)	C-1	None	N.A.	N.A.
	C-2	Plug defective repaired tubes and inspect 100% of the repaired tubes in this S.G.	C-1	None
			C-2	Plug defective repaired tubes
			C-3	Perform action for C-3 result of first sample
	C-3	Inspect all repaired tubes in this S.G., plug defective tubes and inspect 20% of the repaired tubes in each other S.G. Notification to NRC pursuant to §50.72(b)(2) of 10 CFR Part 50	All other S.G.s are C-1	None
			Some S.G.s C-2 but no additional S.G. are C-3	Perform action for C-2 result of first sample

(continued)

TABLE 5.5.9-3

STEAM GENERATOR REPAIRED TUBE INSPECTION
(continued)

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required
			Additional S.G. is C-3	Inspect all repaired tubes in each S.G. and plug defective tubes. Notification to NRC pursuant to §50.72(b)(2) of 10 CFR Part 50

(1) Each repair method is considered a separate population for determination of initial inservice inspection and scope expansion.

(2) The inspection of repaired tubes may be performed on tubes from 1 to 4 steam generators based on outage plans.

(continued)

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

INSERT 5.5.16

b. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 48.1 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.20% of the containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

2. Air lock testing acceptance criteria are:

a) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$;

b) For each door, leakage rate is $\leq 0.005\ L_a$ when pressurized to ≥ 10 psig.

e. The provisions or Technical Specification SR 3.0.2 do not apply to the test frequencies in the Containment Leakage Rate Testing Program.

f. The provisions of Technical Specification SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

INSERT 5.5.16

3. The unit is excepted from post-modification integrated leakage rate testing requirements associated with steam generator replacement.

5.6 Reporting Requirements (continued)

5.6.10 Steam Generator Tube Inspection Report

INSERT 5.6.10

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged or repaired in each steam generator shall be reported to the Commission.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission in a report within 12 months following completion of the inspection. This report shall include:

   1) Number and extent of tubes and sleeves inspected,

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

   3) Identification of tubes plugged or repaired.

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

INSERT 5.6.10

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG;

b. Active degradation mechanisms found;

c. Nondestructive examination techniques utilized for each degradation mechanism;

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

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

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

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

INSERT 5.6.10

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG;

b. Active degradation mechanisms found;

c. Nondestructive examination techniques utilized for each degradation mechanism;

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

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

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

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

ATTACHMENT 3

RETYPED TECHNICAL SPECIFICATIONS

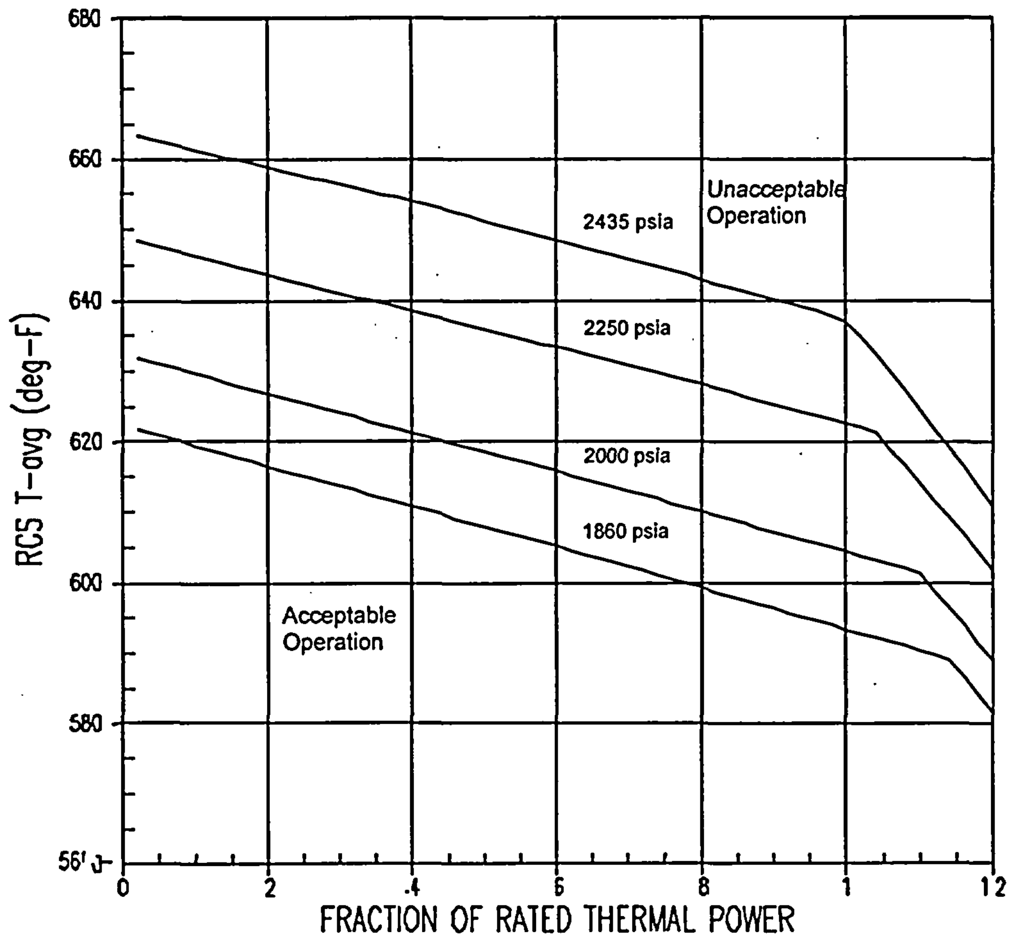

Figure 2.1.1-1 (page 1 of 1)
Reactor Core Safety Limits

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
W. Not used.			
X. One or more Containment Pressure - Environmental Allowance Modifier channel(s) inoperable.	X.1	Place channel(s) in trip.	6 hours
	<u>OR</u>		
	X.2	Be in MODE 3.	12 hours

Table 3.3.1-1 (page 3 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
9.	Pressurizer Water Level - High	1[g]	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 93.8% of instrument span
10.	Reactor Coolant Flow - Low	1[g]	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 88.8% of indicated loop flow
11.	Not Used					
12.	Undervoltage RCPs	1[g]	2/bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 10105 Vac
13.	Underfrequency RCPs	1[g]	2/bus	M	SR 3.3.1.9 SR 3.3.1.10 SR 3.3.1.16	≥ 57.1 Hz
14.	Steam Generator (SG) Water Level Low-Low[l]					
	a. Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 20.6% of Narrow Range Instrument Span
	b. Steam Generator Water Level Low-Low (Normal Containment Environment)	1[p],2[p]	4 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≥ 16.6% of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(m) Not used.
(p) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.1-1 (page 4 of 8)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
14. Steam Generator (SG) Water Level Low-Low[l] (continued)					
c. Not used.					
d. Containment Pressure - Environmental Allowance Modifier	1,2	4	X	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 SR 3.3.1.16	≤ 2.0 psig
15. Not Used					

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(l) The applicable MODES for these channels in Table 3.3.2-1 are more restrictive.
(n) Not used.
(o) Not used.

Table 3.3.1-1 (page 7 of 8)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following setpoint by more than 1.23% of ΔT span (1.85% RTP).

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left(\frac{1}{1+\tau_3 s}\right) \leq \Delta T_0 \left\{ K_1 - K_2 \left[\frac{(1+\tau_4 s)}{(1+\tau_5 s)} T \frac{1}{(1+\tau_6 s)} - T' \right] + K_3 (P - P') - f_1(\Delta I) \right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T′ is the nominal T_{avg} at RTP, ≤ 585.3°F.

P is the measured pressurizer pressure, psig.
P′ is the nominal RCS operating pressure = 2235 psig.

K_1 = 1.1950	K_2 = 0.0251/°F	K_3 = 0.00116/psig
$\tau_1 \geq 8$ sec	$\tau_2 \leq 3$ sec	$\tau_3 = 0$ sec
$\tau_4 \geq 28$ sec	$\tau_5 \leq 4$ sec	$\tau_6 = 0$ sec

$f_1(\Delta I)$ =	-0.0325 {21% + ($q_t - q_b$)}	when $q_t - q_b$ < -21% RTP
	0% of RTP	when -21% RTP ≤ $q_t - q_b$ ≤ 8% RTP
	0.02973 {($q_t - q_b$) - 8%}	when $q_t - q_b$ > 8% RTP

where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

Table 3.3.1-1 (page 8 of 8)
Reactor Trip System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following setpoint by more than 1.21% of ΔT span (1.82% RTP).

$$\Delta T\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left(\frac{1}{1+\tau_3 s}\right) \leq \Delta T_O\left\{K_4 - K_5\frac{(\tau_7 s)}{(1+\tau_7 s)}\left(\frac{1}{1+\tau_6 s}\right)T - K_6\left[T\frac{1}{(1+\tau_6 s)} - T''\right] - f_2(\Delta I)\right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T″ is the nominal T_{avg} at RTP, ≤ 585.3°F.

K_4 = 1.1073

K_5 = 0.02/°F for increasing T_{avg}
0/°F for decreasing T_{avg}

K_6 = 0.0015/°F when T > T″
0/°F when T ≤ T″

$\tau_1 \geq 8$ sec

$\tau_2 \leq 3$ sec

$\tau_3 = 0$ sec

$\tau_6 = 0$ sec

$\tau_7 \geq 10$ sec

$f_2(\Delta I)$ = 0% RTP for all ΔI.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. Not used.		
N. One or more Containment Pressure - Environmental Allowance Modifier channel(s) inoperable.	N.1 Place channel(s) in trip.	6 hours
	<u>OR</u>	
	N.2.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	N.2.2 Be in MODE 4.	18 hours
O. One channel inoperable.	----- NOTE ----- LCO 3.0.4 is not applicable.	
	O.1 Place channel in trip.	1 hour
	<u>AND</u>	
	O.2 Restore channel to OPERABLE status.	During performance of the next required COT

(continued)

Table 3.3.2-1 (page 1 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6 SR 3.3.2.13	NA
c. Containment Pressure - High 1	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 4.5 psig
d. Pressurizer Pressure - Low	1,2,3[b]	4	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 1834 psig
e. Steam Line Pressure - Low	1,2,3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 609 psig[c]
2. Containment Spray					
a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Containment Pressure High - 3	1,2,3	4	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 28.3 psig

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) interlock and below P-11 unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds.

Table 3.3.2-1 (page 3 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
4. Steam Line Isolation					
a. Manual Initiation	1,2[i], 3[i]	2	F	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2[i], 3[i]	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Automatic Actuation Logic and Actuation Relays (MSFIS)	1, 2[i],3[i]	2 trains[o]	G	SR 3.3.2.2	NA
d. Containment Pressure - High 2	1,2[i], 3[i]	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 18.3 psig
e. Steam Line Pressure					
(1) Low	1,2[i], 3[b][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 609 psig[c]
(2) Negative Rate - High	3[g][i]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 124 psi[h]

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(b) Above the P-11 (Pressurizer Pressure) Interlock and below P-11 unless the Function is blocked.
(c) Time constants used in the lead/lag controller are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds.
(g) Below the P-11 (Pressurizer Pressure) Interlock; however, may be blocked below P-11 when safety injection on low steam line pressure is not blocked.
(h) Time constant utilized in the rate/lag controller is ≥ 50 seconds.
(i) Except when all MSIVs are closed.
(o) Each train requires a minimum of two programmable logic controllers to be OPERABLE.

Table 3.3.2-1 (page 4 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays (SSPS)	1, 2[j], 3[j]	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6 SR 3.3.2.14	NA
b. Automatic Actuation Logic and Actuation Relays (MSFIS)	1, 2[j], 3[j]	2 trains[o]	G	SR 3.3.2.2	NA
c. SG Water Level - High High (P-14)	1, 2[j]	4 per SG	I	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 91.4% of Narrow Range Instrument Span
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
e. Steam Generator Water Level Low-Low[q]					
(1) Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2[j], 3[j]	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 20.6% of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs are closed.
(o) Each train requires a minimum of two programmable logic controllers to be OPERABLE.
(q) Feedwater isolation only.

Table 3.3.2-1 (page 5 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
5. Turbine Trip and Feedwater Isolation					
e. Steam Generator Water Level Low-Low[q] (continued)					
(2) Steam Generator Water Level Low-Low (Normal Containment Environment)	1[r], 2[j,r], 3[j,r]	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 16.6% of Narrow Range Instrument Span
(3) Not used.					
(4) Containment Pressure - Environmental Allowance Modifier	1, 2[j], 3[j]	4	N	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 2.0 psig

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(j) Except when all MFIVs are closed.
(k) Not used.
(l) Not used.
(q) Feedwater isolation only.
(r) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE(a)
6. Auxiliary Feedwater					
a. Manual Initiation	1, 2, 3	1/pump	P	SR 3.3.2.8	NA
b. Automatic Actuation Logic and Actuation Relays (SSPS)	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA
c. Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	1,2,3	2 trains	Q	SR 3.3.2.3	NA
d. SG Water Level Low-Low					
(1) Steam Generator Water Level Low-Low (Adverse Containment Environment)	1, 2, 3	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 20.6% of Narrow Range Instrument Span
(2) Steam Generator Water Level Low-Low (Normal Containment Environment)	1(r), 2(r), 3(r)	4 per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ 16.6% of Narrow Range Instrument Span

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(r) Except when the Containment Pressure – Environmental Allowance Modifier channels in the same protection sets are tripped.

Table 3.3.2-1 (page 7 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE[a]
6. Auxiliary Feedwater					
d. SG Water Level Low-Low (continued)					
(3) Not Used.					
(4) Containment Pressure - Environmental Allowance Modifier	1, 2, 3	4	N	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ 2.0 psig
e. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
f. Loss of Offsite Power	1,2,3	2 trains	R	SR 3.3.2.7 SR 3.3.2.10	NA
g. Trip of all Main Feedwater Pumps	1,2[n]	2 per pump	J	SR 3.3.2.8	NA

(continued)

(a) The Allowable Value defines the limiting safety system setting. See the Bases for the Trip Setpoints.
(k) Not used.
(l) Not used.
(n) Trip function may be blocked just before shutdown of the last operating main feedwater pump and restored just after the first main feedwater pump is put into service following performance of its startup trip test.

3.4 REACTOR COOLANT SYSTEM (RCS)

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

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ 2223 psig;

b. RCS average temperature ≤ 590.1°F; and

c. RCS total flow rate ≥ 382,630 gpm.

APPLICABILITY: MODE 1.

-----NOTE-----
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1	Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ 2223 psig.	12 hours
SR 3.4.1.2	Verify RCS average temperature is ≤ 590.1°F.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 382,630 gpm.	12 hours
SR 3.4.1.4	-------------------NOTE------------------- Calculated rather than verified by precision heat balance when performed prior to THERMAL POWER exceeding 75% RTP. -- Verify by precision heat balance that RCS total flow rate is ≥ 382,630 gpm.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP. <u>AND</u> 18 months

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side narrow range water levels are ≥ 7% for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required loops inoperable. OR No RCS or RHR loop in operation.	B.1	Suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SDM of LCO 3.1.1.	Immediately
	AND		
	B.2	Initiate action to restore one loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side narrow range water levels are $\geq$ 7% for required RCS loops.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops - MODE 5, Loops Filled

LCO 3.4.7

One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side wide range water level of at least two steam generators (SGs) shall be ≥ 86%.

---NOTES---

1. The RHR pump of the loop in operation may be removed from operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SDM of LCO 3.1.1; and

   b. Core outlet temperature is maintained at least 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with any RCS cold leg temperature ≤ 275°F unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side wide range water level is ≥ 86% in required SGs.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day primary to secondary LEAKAGE through any one SG.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary to secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists. OR Primary to secondary LEAKAGE not within limit.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	-------NOTES------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary to secondary LEAKAGE. ------------------------------- Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.13.2	-------NOTE------- Not required to be performed until 12 hours after establishment of steady state operation. ------------------------------- Verify primary to secondary LEAKAGE is ≤ 150 gallons per day through any one SG.	72 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

<u>AND</u>

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

APPLICABILITY: MODES 1 2, 3, and 4.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1	Verify tube integrity of the affected tube(s) is maintained until the next inspection.	7 days
	<u>AND</u>		
	A.2	Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> SG tube integrity not maintained.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
4	≤ 85
3	≤ 45
2	≤ 27

5.5 Programs and Manuals (continued)

5.5.8 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

5.5.9 Steam Generator (SG) Program

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

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during a SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes.

(continued)

5.5 Programs and Manuals (continued)

5.5.9 Steam Generator (SG) Program (continued)

Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

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

1. Structural integrity performance criterion: All 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, and cooldown, and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 (3?P) against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm total for all four steam generators.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

(continued)

5.5 Programs and Manuals (continued)

5.5.9 Steam Generator (SG) Program (continued)

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

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

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

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

e. Provisions for monitoring operational primary to secondary LEAKAGE.

(continued)

5.5 Programs and Manuals (continued)

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Rev. 2, and uses the test procedure guidance in Regulatory Guide 1.52, Revision 2, Positions C.5.a, C.5.c and C.5.d.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass < 1.0% when tested at the system flowrate specified below.

ESF Ventilation System	Flowrate
Control Room Filtration	2000 cfm, ± 200 cfm
Control Room Pressurization	500 cfm, +500, -50 cfm
Emergency Exhaust System	9000 cfm, ± 900 cfm

(continued)

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass < 1.0% when tested at the system flowrate specified below.

ESF Ventilation System	Flowrate
Control Room Filtration	2000 cfm, ± 200 cfm
Control Room Pressurization	500 cfm, +500, -50 cfm
Emergency Exhaust System	9000 cfm, ± 900 cfm

c. Demonstrate for each of the ESF systems within 31 days after removal that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and the relative humidity specified below.

ESF Ventilation System	Penetration	RH
Control Room Filtration	2.0%	70%
Control Room Pressurization	2.0%	70%
Emergency Exhaust System	2.0%	70%

d. Demonstrate at least once per 18 months for each of the ESF systems that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than the value specified below when tested at the system flowrate specified below.

ESF Ventilation System	Delta P	Flowrate
Control Room Filtration	5.4" WG	2000 cfm, ± 200 cfm
Control Room Pressurization	5.4" WG	500 cfm, +500,- 50 cfm
Emergency Exhaust System	5.4" WG	9000 cfm, ± 900 cfm

(continued)

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

e. Demonstrate at least once per 18 months that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ANSI 510-1975 and corrected to design nameplate voltage settings.

ESF Ventilation System	Wattage
Control Room Pressurization	15 ± 2 KW
Emergency Exhaust System	37 ± 3 KW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Radwaste System, the quantity of radioactivity contained in gas storage tanks and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure, Revision 0". The liquid radwaste quantities shall be determined in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures, Revision 2".

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Radwaste System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in the outdoor liquid radwaste tanks listed below that are not

(continued)

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste System is less than the quantities determined in accordance with the Standard Review Plan, Section 15.7.3:

a. Reactor Makeup Water Storage Tank,
b. Refueling Water Storage Tank,
c. Condensate Storage Tank, and
d. Outside temporary tanks, excluding demineralizer vessels and the liner being used to solidify radioactive waste.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. an API gravity or an absolute specific gravity within limits,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a water and sediment content within limits for ASTM 2D fuel oil.

b. Other properties for ASTM 2D fuel oil are analyzed within 31 days following sampling and addition of new fuel oil to storage tanks; and

c. Total particulate concentration of the stored fuel oil is ≤ 10 mg/l when tested every 31 days based on applicable ASTM D-2276 standards.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

(continued)

5.5 Programs and Manuals (continued)

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

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

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

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

d. Proposed changes that meet the criteria of Specification 5.5.14b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

(continued)

5.5.15 Safety Function Determination Program (SFDP) (continued)

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.5.16 Containment Leakage Rate Testing Program

a. A program shall 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. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exceptions:

1. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by ASME Section XI Code, Subsection IWL, except where relief has been authorized by the NRC.

(continued)

5.5 Programs and Manuals

5.5.16 Containment Leakage Rate Testing Program (continued)

2. The visual examination of the steel liner plate inside containment intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by ASME Section XI Code, Subsection IWE, except where relief has been authorized by the NRC.

3. The unit is excepted from post-modification integrated leakage rate testing requirements associated with steam generator replacement.

b. The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is 48.1 psig.

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.20% of the containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $< 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

2. Air lock testing acceptance criteria are:

a) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$;

b) For each door, leakage rate is $\leq 0.005\ L_a$ when pressurized to $\geq$ 10 psig.

e. The provisions or Technical Specification SR 3.0.2 do not apply to the test frequencies in the Containment Leakage Rate Testing Program.

f. The provisions of Technical Specification SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Occupational Radiation Exposure Report

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors), for whom monitoring was performed, receiving an annual deep dose equivalent > 100 mrems and the associated collective deep dose equivalent (reported in person-rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance, waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket ionization chamber, thermoluminescence dosimeter (TLD), electronic dosimeter, or film badge measurements. Small exposures totalling < 20% percent of the individual total dose need not be accounted for. In the aggregate, at least 80% percent of the total deep dose equivalent received from external sources should be assigned to specific major work functions. The report covering the previous calendar year shall be submitted by April 30 of each year.

5.6.2 Annual Radiological Environmental Operating Report

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 1 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period.

The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in a format similar to the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.6.3 Radioactive Effluent Release Report

The Radioactive Effluent Release Report covering the operation of the unit during the previous year shall be submitted prior to May 1 of each year. in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR 50.36a and 10 CFR Part 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. Moderator Temperature Coefficient limits in Specification 3.1.3,

2. Shutdown Bank Insertion Limit for Specification 3.1.5,

3. Control Bank Insertion Limits for Specification 3.1.6,

4. Axial Flux Difference Limits for Specification 3.2.3,

5. Heat Flux Hot Channel Factor, $F_Q(Z)$ F_Q^{RTP}, K(Z), W(Z) and F_Q Penalty Factors for Specification 3.2.1,

6. Nuclear Enthalpy Rise Hot Channel Factor $F_{\Delta H}$, $F_{\Delta H}^{RTP}$, and Power Factor Multiplier, $PF_{\Delta H}$, limits for Specification 3.2.2.

7. Shutdown Margin Limits for Specifications 3.1.1, 3.1.4, 3.1.5, 3.1.6, and 3.1.8.

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY", July 1985 (W Proprietary).

2. WCAP-10216-P-A, REV. 1A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL AND FQ SURVEILLANCE TECHNICAL SPECIFICATION," February 1994 (W Proprietary).

3. WCAP-10266-P-A, REV. 2, "THE 1981 VERSION OF WESTINGHOUSE EVALUATION MODEL USING BASH CODE," March 1987 (W Proprietary).

4. NRC Safety Evaluation Reports dated July 1, 1991, "Acceptance for Referencing of Topical Report WCAP-12610 'VANTAGE + Fuel Assembly Reference Core Report' (TAC NO 77268)," and September 15, 1994, "Acceptance for Referencing of Topical Report WCAP-12610, Appendix B, Addendum 1, 'Extended Burnup Fuel Design Methodology and ZIRLO Fuel Performance Models' (TAC No. M86416)" (WCAP-12610-P-A).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

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

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, hydrostatic testing and PORV lift setting as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

(continued)

5.6 Reporting Requirements

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

1. Specification 3.4.3, "RCS Pressure and Temperature (P/T) Limits," and

2. Specification 3.4.12, "Cold Overpressure Mitigation System (COMS)."

b. The analytical methods used to determine the RCS pressure and temperature and COMS PORV limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. NRC letter, CALLAWAY PLANT, UNIT 1 – ISSUANCE OF AMENDMENT RE: PRESSURE TEMPERATURE LIMITS REPORT (TAC NOS. MA5631 and MA7287), dated March 24, 2000.

2. WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves, January, 1996".

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 Not used.

5.6.8 PAM Report

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

5.6.9 Not used.

(continued)

5.6 Reporting Requirements (continued)

5.6.10 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG;

b. Active degradation mechanisms found;

c. Nondestructive examination techniques utilized for each degradation mechanism;

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

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

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

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

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

As provided in paragraph 20.1601(c) of 10 CFR Part 20, the following controls shall be applied to high radiation areas in place of the controls required by paragraph 20.1601 (a) and (b) of 10 CFR Part 20:

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be barricaded and conspicuously posted as a high radiation area. Such barricades may be opened as necessary to permit entry or exit of personnel or equipment;

b. Access to, and activities in, each such area shall be controlled by means of Radiation Work Permit (RWP) or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

c. Individuals qualified in radiation protection procedures and personnel continuously escorted by such individuals may be exempted from the requirement for an RWP or equivalent while performing their assigned duties provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously displays radiation dose rates in the area; or

2. A radiation monitoring device that continuously integrates the radiation dose rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

3. A radiation monitoring device that continuously transmits does rate and cumulative dose rate information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area, or

4. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and

(continued)

5.7 High Area Radiation Area

5.7.1 High Radiation Areas with Dose Rates Not Exceeding 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with individuals in the area who are covered by such surveillance.

e. Except for individuals qualified in radiation protection procedures, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them.

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation:

a. Each entryway to such an area shall be conspicuously posted as a high radiation area and shall be provided with a locked or continuously guarded door or gate that prevents unauthorized entry, and, in addition:

1. All such door and gate keys shall be maintained under the administrative control of the Shift Supervisor/Operating Supervisor or Health Physics Supervision, or his or her designee.

2. Doors and gates shall remain locked except during periods of personnel or equipment entry or exit.

b. Access to, and activities in, each such area shall be controlled by means of an RWP or equivalent that includes specification of radiation dose rates in the immediate work area(s) and other appropriate radiation protection equipment and measures.

(continued)

5.7 High Area Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

c. Individuals qualified in radiation protection procedures may be exempted from the requirement for an RWP or equivalent while performing radiation surveys in such areas provided that they are otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual or group entering such an area shall possess:

1. A radiation monitoring device that continuously integrates the radiation rates in the area and alarms when the device's dose alarm setpoint is reached, with an appropriate alarm setpoint, or

2. A radiation monitoring device that continuously transmits dose rate and cumulative dose information to a remote receiver monitored by radiation protection personnel responsible for controlling personnel radiation exposure within the area with the means to communicate with and control every individual in the area, or

3. A self-reading dosimeter (e.g., pocket ionization chamber or electronic dosimeter) and

(i) Be under the surveillance, as specified in the RWP or equivalent, while in the area, of an individual qualified in radiation protection procedures, equipped with a radiation monitoring device that continuously displays radiation dose rates in the area; who is responsible for controlling personnel exposure within the area, or

(ii) Be under the surveillance as specified in the RWP or equivalent, while in the area, by means of closed circuit television, of personnel qualified in radiation protection procedures, responsible for controlling personnel radiation exposure in the area, and with the means to communicate with and control every individual in the area, or

4. In those cases where options (2) and (3), above, are impractical or determined to be inconsistent with the "As Low As is Reasonably

(continued)

5.7 High Area Radiation Area

5.7.2 High Radiation Areas with Dose Rates Greater than 1.0 rem/hour at 30 Centimeters from the Radiation Source or from any Surface Penetrated by the Radiation, but less than 500 rads/hour at 1 Meter from the Radiation Source or from any Surface Penetrated by the Radiation: (continued)

Achievable" principle, a radiation monitoring device that continuously displays radiation dose rates in the area.

e. Except for individual qualified in radiation protection procedures or personnel continuously escorted by such individuals, entry into such areas shall be made only after dose rates in the area have been determined and entry personnel are knowledgeable of them.

f. Such individual areas that are within a larger area, such as PWR containment, where no enclosure exists for the purpose of locking and where no enclosure can reasonably be constructed around the individual area need not be controlled by a locked door or gate nor continuously guarded, but shall be barricaded, conspicuously posted, and a clearly visible flashing light shall be activated at the area as a warning device.

ATTACHMENT 4

PROPOSED TECHNICAL SPECIFICATION BASES CHANGES
(for information only)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

requires

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which ~~corresponds to a 95% probability~~ that the minimum departure from nucleate boiling ratio (DNBR) of the limiting rod during Condition I and II events is greater than or equal to the ~~DNBR limit of the DNBR correlation being used (the WRB-2 correlation for VANTAGE 5 fuel for most safety analyses). The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95% probability with 95% confidence that DNB will not occur when the minimum DNBR is at the DNBR limit (1.17 for the WRB-2 correlation). In meeting this design basis, for ITDP analyses, uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are considered statistically such that there is at least a 95% probability with 95% confidence level that the minimum DNBR for the limiting rod is greater than or equal to the DNBR limit. The uncertainties in the above plant parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty, combined with the correlation DNBR limit, establishes a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties.~~ The ~~design DNBR~~ values are ~~1.33 and 1.34~~ for thimble and typical cells, respectively, for VANTAGE 5 fuel. In addition, margin has been maintained by meeting safety analysis DNBR limits of ~~1.61 and 1.69~~ for thimble and typical cells, respectively, for VANTAGE 5 fuel. The design DNBRs of ~~1.33 and 1.35 (STD/OFA) and 1.33 and 1.34 (V5)~~ are considered design bases limits for fission barriers for consideration in the 10 CFR 50.59 process. Reference 5 discusses three transients analyzed with the W-3 DNBR correlation.

DNBR design limits

design limit DNBR

INSERT B2.1.1

limit

1.21 and 1.22

1.55 and 1.59

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation

(continued)

INSERT B 2.1.1

In meeting this design basis, for Revised Thermal Design Procedure (RTDP) analyses, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation (WRB-2) predictions are combined statistically to obtain the overall DNBR uncertainty factor. This DNBR uncertainty factor is used to define the design limit DNBR, which corresponds to a 95% probability with 95% confidence that DNB will not occur on the limiting fuel rods during Condition I and II events. Since the parameter uncertainties are considered in determining the RTDP design limit DNBR values, the plant safety analyses are performed using input parameters at their nominal values.

BASES

BACKGROUND (continued)

temperature. Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant. Reference 6 further discusses the fuel centerline temperature design basis.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the limiting hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System Allowable Values in Table 3.3.1-1, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, RCS flow, ΔI, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Protection for these reactor core SLs is provided by the steam generator safety valves and the following automatic reactor trip functions:

a. High pressurizer pressure trip;

(continued)

BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the two-sided tolerance band for rack calibration accuracy ~~(typically ± 15 mV).~~

The Trip Setpoints listed in Table B 3.3.1-1 and used in the bistables are based on the analytical limits stated in Reference 2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and harsh ~~severe~~ environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 4), the Trip Setpoints ~~Allowable Values~~ specified in Table B 3.3.1-1 ~~in the accompanying LCO~~ are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in Reference 6. INSERT B 3.3.1A The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. ~~One example of such a change in measurement error is drift during the surveillance interval.~~ If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

Setpoints in accordance with the Allowable Value ensure that design limits are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values of Table 3.3.1-1 are the LSSS.

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Allowable Values listed in Table 3.3.1-1 in the accompanying LCO, except for Functions 14.a and 14.b, are based on the methodology described in Reference 6, and reviewed in support of Amendments 15, 43, 57, 84, 102, and 125, which incorporates all of the known uncertainties applicable for each channel. INSERT B 3.3.1B The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these

(continued)

INSERT B 3.3.1 A

The methodology used to calculate the Trip Setpoints for Functions 14.a and 14.b in Table B 3.3.1-1 is described in Reference 17. This is the same basic square root sum of the squares (SRSS) methodology described in References 6 and 18 (Reference 18 was reviewed and approved by NRC in support of Callaway Amendment 125 dated April 13, 1998), but with the inclusion of refinements to better reflect plant calibration practices and equipment performance. These refinements include the incorporation of a sensor reference accuracy term to address repeatability effects when performing a single pass calibration (i.e., one up and one down pass at several points verifies linearity and hysteresis, but not repeatability). In addition, sensor and rack error terms for calibration accuracy and drift are grouped in the Channel Statistical Allowance equation with their dependent M&TE terms, then combined with the other independent error terms using the SRSS methodology.

INSERT B 3.3.1 B

The Allowable Values for Functions 14.a and 14.b in the accompanying LCO are based on the Trip Setpoints and are determined by subtracting the rack calibration accuracy from the Trip Setpoint.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

9. Pressurizer Water Level - High (continued)

pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level - High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

10. Reactor Coolant Flow – Low

The Reactor Coolant Flow - Low trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow - Low channels per loop to be OPERABLE in MODE 1 above P-7 (two-out-of-three trip logic). The Trip Setpoint is ≥ 90% of ~~loop Minimum Measured Flow (MMF = 95,660 gpm).~~ indicated loop flow.

INSERT B 3.3.1 C

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core because of the higher power level. In MODE 1 below the P-8 setpoint and above the P-7 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

11 Not used.

12. Undervoltage Reactor Coolant Pumps

The Undervoltage RCP reactor trip Function ensures that protection is provided against violating the DNBR limit due to a

INSERT B 3.3.1 C

At the beginning of each cycle the plant will normalize the RCS flow transmitters during steady state, normal operating pressure, normal operating temperature (NOP/NOT) conditions such that they indicate at 100% flow in each respective loop, then verify the loop flow indications at an intermediate plateau and again at 100% rated thermal power. 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% of span, which is based on the indicated flow input from the RCS flow transmitters.

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

13. Underfrequency Reactor Coolant Pumps (continued)

57.2 Hz. The time delay set on the underfrequency relay prevents spurious trips caused by transient frequency perturbations. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low Trip Setpoint is reached.

The LCO requires two Underfrequency RCP channels per bus to be OPERABLE, a total of four channels. The Trip Setpoint is ≥ 57.2 Hz.

In MODE 1 above the P-7 setpoint, the Underfrequency RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since the core is not producing sufficient power to generate DNB conditions. Above the P-7 setpoint, the reactor trip on Underfrequency-RCPs is automatically enabled.

14. Steam Generator Water Level - Low Low

The SG Water Level - Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters also provide input to the SG Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level. As discussed in Reference 7, the SG Water Level - Low Low trip function has been modified to allow a lower Trip Setpoint under normal containment environmental conditions~~, and a delayed trip when THERMAL POWER is less than or equal to 22.41% RTP~~. The EAM~~/TTD~~ circuitry reduces the potential for inadvertent trips via the Environmental Allowance Modifier (EAM), enabled on containment pressure exceeding its setpoint~~, and the Trip Time Delay (TTD), enabling time delays dependent on vessel ΔT~~ as listed in Table B 3.3.1-1. Because the SG Water Level transmitters (d/p cells) are located inside containment, they may experience adverse environmental conditions due to a feedline break. The EAM function is used to monitor the presence of adverse containment conditions (elevated

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

14. Steam Generator Water Level – Low Low (continued)

pressure) and enables the Steam Generator Water Level Low-Low (Adverse) trip setpoint to reflect the increased transmitter uncertainties due to this harsh environment. The EAM enables a lower Steam Generator Water Level - Low-Low (Normal) trip setpoint when these conditions are not present, thus allowing more margin to trip for normal operating conditions. ~~The TTD delays reactor trip on SG Water Level Low-Low, thereby providing additional operational margin during early power ascension by allowing the operator time to recover level when the primary side load is sufficiently small to not require an earlier trip. The TTD continuously monitors primary side power using Vessel ΔT. Scaling of the Vessel ΔT channels is dependent on the loop-specific values for ΔT_0, discussed under the OTΔT and OPΔT trips. Two time delays are provided, based on the primary side power level; the magnitude of the trip delay decreases with increasing power.~~ If the EAM ~~or TTD~~ trip function ~~have~~ has inoperable required channels, it is acceptable to place the inoperable channels in the tripped condition and continue operation. Placing the inoperable channels in the trip mode enables the Steam Generator Water Level - Low-Low (Adverse) function, for the EAM. ~~or removes the trip delay for the TTD.~~ If the Steam Generator Water Level - Low-Low (Normal) trip function has an inoperable required channel, the inoperable channel must be tripped, subject to the LCO Applicability footnote.

The LCO requires four channels of SG Water Level - Low Low per SG to be OPERABLE because these channels are shared between protection and control. All SG Water Level-Low Low reactor trip Functions use two-out-of-four logic. As with other protection functions, the single failure criterion applies. The Trip Setpoints for the SG Water Level Low-Low (Adverse Containment Environment) and (Normal Containment Environment) bistables are ~~≥ 27.0% and ≥ 21.6%~~ ≥ 21.0% and ≥ 17.0% of narrow range span, respectively. ~~The Trip Setpoints for the Vessel ΔT (Power-1) and (Power-2) bistables are ≤ Vessel ΔT Equivalent to 12.41% RTP and ≤ Vessel ΔT Equivalent to 22.41% RTP, respectively, with corresponding trip time delays of ≤ 232 seconds and ≤ 122 seconds.~~ The Trip Setpoint for the Containment Pressure - Environmental Allowance Modifier bistables is ≤ 1.5 psig.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level - Low Low trip must be OPERABLE. The SG Water Level Low-Low (Normal Containment Environment) channels do not provide protection when the Containment Pressure –

(continued)

BASES

ACTIONS (continued)

W.1 and W.2

Not used.

~~Condition W applies to the Trip Time Delay (TTD) circuitry enabled for the SG Water Level - Low Low trip Function when THERMAL POWER is less than or equal to 22.41% RTP in MODES 1 and 2. With one or more Vessel ΔT Equivalent (Power-1, Power-2) channel(s) inoperable, the associated Vessel ΔT channel(s) must be placed in the tripped condition within 6 hours. If the inoperability impacts the Power-1 and Power-2 portions of the TTD circuitry (e.g., Vessel ΔT RTD failure), both the Power-1 and Power-2 bistables in the affected protection set(s) are placed in the tripped condition. However, if the inoperability is limited to either the Power-1 or Power-2 portion of the TTD circuitry, only the corresponding Power-1 or Power-2 bistable in the affected protection set(s) is placed in the tripped condition. With one or more TTD circuitry delay timer(s) inoperable, both the Vessel ΔT (Power-1) and Vessel ΔT (Power-2) channels are tripped. This automatically enables a zero time delay for that protection channel with either the normal or adverse containment environment level bistable enabled. The Completion Time of 6 hours is based on Reference 7. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. An additional six hours is allowed to place the unit in MODE 3.~~

X.1 and X.2

Condition X applies to the Environmental Allowance Modifier (EAM) circuitry for the SG Water Level - Low Low trip Function in MODES 1 and 2. With one or more EAM channel(s) inoperable, they must be placed in the tripped condition within 6 hours. Placing an EAM channel in trip automatically enables the SG Water Level - Low Low (Adverse Containment Environment) bistable for that protection channel, with its higher SG level Trip Setpoint (a higher trip setpoint means a reactor trip would occur sooner). The Completion Time of 6 hours is based on Reference 7. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. An additional six hours is allowed to place the unit in MODE 3.

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the setpoint methodology.

The Frequency of 18 months is based on the assumed calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified via response time testing per SR 3.3.1.16. See the discussion of ΔT_0 in the Applicable Safety Analyses for the Overtemperature ΔT and Overpower ΔT trip functions. Whenever an RTD is replaced in Function ~~6, 7, or 14.c,~~ 6 or 7, the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed sensing element.

The CHANNEL CALIBRATION of Function 6, Overtemperature ΔT, includes the axial flux difference penalty circuitry in the 7300 Process Protection System cabinets, but does not include the power range neutron detectors. SR 3.3.1.11 and its Notes 1 and 3 govern the performance and timing of the power range neutron detector plateau voltage verification.

Although not required for any safety function, the CHANNEL CALIBRATION of Function 10, Reactor Coolant Flow-Low, will ensure proper performance and normalization of the RCS flow indicators.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by three Notes. Note 1 states that neutron detectors are excluded from the CHANNEL CALIBRATION. Neutron detectors are excluded from the CHANNEL CALIBRATION because it is impractical to set up a test that demonstrates and adjusts neutron detector response to known values of the parameter (neutron flux) that the channel monitors. Note 1 applies to the source range proportional counters, intermediate range ion chambers, and power range ion chambers in the Nuclear Instrumentation System (NIS). Note 2 states that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. Detector plateau curves are obtained, evaluated, and compared to manufacturer's data for the intermediate and power range neutron

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.16

SR 3.3.1.16 verifies that the individual channel actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time verification acceptance criteria are included in Reference 8. No credit was taken in the safety analyses for those channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Reference 8. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor until loss of stationary gripper coil voltage (at which point the rods are free to fall).

The safety analyses include the sum of the following response time components:

(a) Process delay times (e.g., scoop transport delay and thermal lag associated with the narrow range RCS RTDs used in the OTΔT~~,~~ and OPΔT~~, and SG low-low Vessel ΔT (Power-1, Power-2)~~ functions) which are not testable;

(b) Sensing circuitry delay time from the time the trip setpoint is reached at the sensor until a reactor trip is generated by the SSPS;

(c) Any intentional time delay set into the trip circuitry (e.g., undervoltage relay time delay, NLL cards (lag, lead/lag, rate/lag) and NPL cards (PROM logic cards for trip time delay) associated with the OTΔT and OPΔT~~, and SG low-low level Vessel ΔT (Power-1, Power-2)~~) trip functions, and NLL cards (lead/lag) associated with the low pressurizer pressure reactor trip function) to add margin or prevent spurious trip signals;

(d) For the undervoltage RCP trip function, back EMF delay from the time of the loss of the bus voltage until the back EMF voltage generated by the bus loads has decayed;

(e) The time delay for the reactor trip breakers to open; and

(f) The time delay for the control rod drive stationary gripper coil voltage to decay and the RCCA grippers to mechanically release making the rods free to fall (i.e., gripper release time measured during the performance of SR 3.1.4.3).

(continued)

BASES

REFERENCES (continued)

6. Callaway Setpoint Methodology Report, SNP (UE)-565 dated May 1, 1984.

7. Callaway OL Amendment No. 43 dated April 14, 1989.

8. FSAR Section 16.3, Table 16.3-1

9. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

FSAR Table 15.0-4.

11 WCAP-9226-P-A, "Reactor Core Response to Excessive Secondary Steam Releases," Revision 1, ~~January 1978.~~ February 1998.

12. NRC Generic Letter 85-09 dated May 23, 1985.

13. FSAR Section 15.1.1

14. RFR - 18637A.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.

16. FSAR Section 15.4.6.

Westinghouse letter SCP-04-90 dated August 27, 2004.

18. ULNRC-03748 dated February 27, 1998.

Table B 3.3.1-1
(Page 1 of 3)

	FUNCTION	NOMINAL TRIP SETPOINT [a]
1	Manual Reactor Trip	N.A.
2.	Power Range Neutron Flux	
	a. High	≤ 109% RTP
	b. Low	≤ 25% RTP
3.	Power Range Neutron Flux Rate - High Positive Rate	≤ 4.25% RTP with time constant ≥ 2 sec.
4.	Intermediate Range Neutron Flux	≤ 25% RTP
5.	Source Range Neutron Flux	≤ 1.0E5 CPS
6.	Overtemperature ΔT	See Table 3.3.1-1 Note 1
7.	Overpower ΔT	See Table 3.3.1-1 Note 2.
8.	Pressurizer Pressure	
	a. Low	≥ 1885 psig
	b. High	≤ 2385 psig
9.	Pressurizer Water Level - High	≤ 92% of instrument span
10.	Reactor Coolant Flow - Low	≥ 90% of indicated loop flow ~~loop minimum measured flow (MMF=95,660 gpm)~~

(continued)

[a] The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value. This also applies to the Overtemperature ΔT and Overpower ΔT K values per Reference 14.

Table B 3.3.1-1
(Page 2 of 3)

	FUNCTION	NOMINAL TRIP SETPOINT (a)
11	Not used.	
12.	Undervoltage RCPs	≥ 10,584 Vac
13.	Underfrequency RCPs	≥ 57.2 Hz
14	Steam Generator (SG) Water Level Low-Low	
a	Steam Generator Water Level Low-Low (Adverse Containment Environment)	≥ ~~27.0%~~ 21.0% of narrow range instrument span
b.	Steam Generator Water Level Low-Low (Normal Containment Environment)	≥ ~~21.6%~~ 17.0% of narrow range instrument span
c.	~~Vessel ΔT Equivalent including delay timers - Trip Time Delay~~ Not used.	
~~(1)~~	~~Vessel ΔT (Power-1)~~	~~≤ Vessel ΔT Equivalent to 12.41% RTP (with a time delay ≤ 232 sec.)~~
~~(2)~~	~~Vessel ΔT (Power-2)~~	~~≤ Vessel ΔT Equivalent to 22.41% RTP (with a time delay ≤ 122 sec.)~~
d.	Containment Pressure - Environmental Allowance Modifier	≤ 1.5 psig
15.	Not used.	

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value. This also applies to the Overtemperature ΔT and Overpower ΔT K values per Reference 14.

BASES

BACKGROUND (continued)

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the two-sided tolerance band for rack calibration accuracy. ~~(typically ± 15 mV).~~

(continued)

B

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

The Trip Setpoints listed in Table B 3.3.2-1 and used in the bistables are based on the analytical limits stated in Reference 3. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and harsh ~~severe~~ environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the ~~Allowable Values~~ Trip Setpoints specified in Table B3.3.2-1 ~~in the accompanying LCO~~ are conservatively adjusted with respect to the analytical limits. A detailed description of the methodologies used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in Reference 6. The BOP methodology used for Function 6.h is a similar square-root-sum-of-squares (SRSS) methodology as used for the RTS setpoints. The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. ~~One example of such a change in measurement error is drift during the surveillance interval.~~ If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

INSERT B3.3.2A

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

The Allowable Values listed in Table 3.3.2-1 in the accompanying LCO, except for Functions 1.e, 4.e.(1), 5.c, 5.e.(1), 5.e.(2), 6.d.(1), and 6.d.(2), are based on the methodologies described in Reference 6, which incorporate all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

INSERT B 3.3.2.B

(continued)

INSERT B 3.3.2 A

The methodology used to calculate the Trip Setpoints for Functions 1.e, 4.e.(1), 5.c, 5.e.(1), 5.e.(2), 6.d.(1), and 6.d.(2) in Table B 3.3.2-1 is described in Reference 18. This is the same basic square root sum of the squares (SRSS) methodology described in References 6 and 19 (Reference 19 was reviewed and approved by NRC in support of Callaway Amendment 125 dated April 13, 1998), but with the inclusion of refinements to better reflect plant calibration practices and equipment performance. These refinements include the incorporation of a sensor reference accuracy term to address repeatability effects when performing a single pass calibration (i.e., one up and one down pass at several points verifies linearity and hysteresis, but not repeatability). In addition, sensor and rack error terms for calibration accuracy and drift are grouped in the Channel Statistical Allowance equation with their dependent M&TE terms, then combined with the other independent error terms using the SRSS methodology.

INSERT B 3.3.2 B

The Allowable Values for Functions 1.e, 4.e.(1), 5.c, 5.e.(1), 5.e.(2), 6.d.(1), and 6.d.(2) in the accompanying LCO are based on the Trip Setpoints and are determined by subtracting (for low setpoint trips) or adding (for high setpoint trips) the rack calibration accuracy from/to the Trip Setpoint.

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

5. Turbine Trip and Feedwater Isolation (continued)

a. Turbine Trip and Feedwater Isolation - Automatic Actuation Logic and Actuation Relays (SSPS)

Automatic Actuation Logic and Actuation Relays in the SSPS consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Feedwater Isolation - Automatic Actuation Logic and Actuation Relays (MSFIS)

Automatic Actuation Logic and Actuation Relays in the MSFIS consist of the same features and operate in the same manner as described for ESFAS Function 4.c.

c. Turbine Trip and Feedwater Isolation - Steam Generator Water Level - High High (P-14)

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels per SG are required to satisfy the requirements with a two-out-of-four logic in any SG resulting in actuation signal generation.

The transmitters (d/p cells) are located inside containment However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the Trip Setpoint reflects only steady state instrument uncertainties. The Trip Setpoint is ≤ ~~78%~~ 91.0% of narrow range span.

d. Turbine Trip and Feedwater Isolation - Safety Injection

Turbine Trip and Feedwater Isolation are also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

d. Turbine Trip and Feedwater Isolation - Safety Injection (continued)

Function 1, SI, is referenced for all initiating functions and requirements.

e. Feedwater Isolation - Steam Generator Water Level - Low Low

SG Water Level - Low Low provides protection against a loss of heat sink by ensuring the isolation of normal feedwater and AFW delivery to the steam generators. Given the location of the feedwater line check valves inside containment downstream of the point where AFW connects to the main feedwater piping, closure of the MFIVs is required to assure AFW flow is not diverted. A feedwater line break or a loss of MFW would result in a loss of SG water level. SG Water Level - Low Low provides input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system, which may then require a protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with two-out-of-four logic (the Environmental Allowance Modifier (EAM) ~~and Trip Time Delay (TTD)~~ function~~s~~ also uses a two-out-of-four logic). Two-out-of-four low level signals in any SG initiates feedwater isolation. As discussed in Reference 11, the SG Water Level - Low Low trip Function has been modified to allow a lower Trip Setpoint under normal containment environmental conditions. ~~and a delayed trip when THERMAL POWER is less than or equal to 22.41% RTP.~~

The EAM~~/TTD~~ circuitry reduces the potential for inadvertent trips via the EAM, enabled on containment pressure exceeding its setpoint~~, and the TTD, enabling time delays dependent on vessel ΔT~~ as listed in Table B 3.3.2-1. Because the SG Water Level transmitters (d/p cells) are located inside containment, they may experience adverse environmental conditions due to a feedline break. The EAM function is used to monitor the presence of adverse containment conditions (elevated pressure) and enables the Steam Generator Water Level - Low Low (Adverse) trip setpoint to reflect the increased transmitter uncertainties due to this harsh environment. The EAM

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

e. Feedwater Isolation - Steam Generator Water Level - Low Low (continued)

enables a lower Steam Generator Water Level - Low Low (Normal) trip setpoint when these conditions are not present, thus allowing more margin to trip for normal operating conditions. ~~The TTD delays feedwater isolation on SG Water Level - Low Low, thereby providing additional operating margin during early power ascension by allowing the operator time to recover level when the primary side load is sufficiently small to not require an earlier isolation. The TTD continuously monitors primary side power using Vessel ΔT. Scaling of the Vessel ΔT channels is dependent on the loop specific values for ΔT_0, discussed under the OTΔT and OPΔT trips. Two time delays are provided, based on the primary side power levels; the magnitude of the trip delay decreases with increasing power.~~ If the EAM ~~or TTD~~ trip function ~~have~~ has inoperable required channels, it is acceptable to place the inoperable channels in the tripped condition and continue operation. Placing the inoperable channels in the trip mode enables the Steam Generator Water Level - Low Low (Adverse) Function, for the EAM. ~~or removes the trip delay for the TTD.~~ If the Steam Generator Water Level - Low Low (Normal) trip Function has an inoperable required channel, the inoperable channel must be tripped, subject to the LCO Applicability footnote.

The SG Water Level - Low Low Trip Setpoints are chosen to reflect both steady state and adverse environment instrument behavior. The Trip Setpoints for the Steam Generator Water Level - Low Low (Adverse Containment Environment) and (Normal Containment Environment) bistables are ~~≥ 27.0% and ≥ 21.6%~~ ≥21.0% and ≥17.0% of narrow range span, respectively. ~~The Trip Setpoints for the Vessel ΔT (Power-1) and (Power-2) bistables are ≤ Vessel ΔT Equivalent to 12.41% RTP and ≤ Vessel ΔT Equivalent to 22.41% RTP, respectively, with corresponding trip time delays of ≤ 232 seconds and ≤ 122 seconds.~~ The Trip Setpoint for the Containment Pressure - Environmental Allowance Modifier bistables is ≤ 1.5 psig.

Turbine Trip and Feedwater Isolation Function 5.c, SG Water Level - High High ~~and Feedwater Isolation Function 5.e.(3), SG Water Level Low Low Vessel ΔT Equivalent,~~ must be OPERABLE in MODES 1 and 2 except when all MFIVs are closed. In

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABIILITY

5. Turbine Trip and Feedwater Isolation (continued)

MODES 3, 4, 5, and 6, Function~~s~~ 5.c ~~and 5.e.(3) are~~ is not required to be OPERABLE. All other Turbine Trip and Feedwater Isolation Functions must be OPERABLE in MODE 1, MODE 2 (except when all MFIVs are closed), and MODE 3 (except when all MFIVs are closed). The SG Water Level Low-Low (Normal Containment Environment) channels do not provide protection when the Containment Pressure – Environmental Allowance Modifier (EAM) channels in the same protection sets are tripped since that enables the SG Water Level Low-Low (Adverse Containment Environment) channels with a higher water level trip setpoint. As such, the SG Water Level Low-Low (Normal Containment Environment) channels need not be OPERABLE when the Containment Pressure – EAM channels in the same protection sets are tripped, as discussed in a footnote to Table 3.3.2-1.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST). A loss of suction pressure, coincident with an auxiliary feedwater actuation signal (AFAS), will automatically realign the pump suctions to the safety related Essential Service Water (ESW) System. The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater - Manual Initiation

Manual initiation of Auxiliary Feedwater can be accomplished from the control room. Each of the three AFW pumps has a pushbutton for manual AFAS initiation The LCO requires three channels to be OPERABLE.

b. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays (SSPS)

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

6. Auxiliary Feedwater (continued)

c. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays (BOP ESFAS)

Automatic actuation logic and actuation relays consist of similar features and operate in a similar manner as described for SSPS in ESFAS Function 1.b.

d. Auxiliary Feedwater - Steam Generator Water Level - Low Low

SG Water Level - Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level - Low Low provides input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system, which may then require a protection function actuation, and a single failure in the other channels providing the protection function actuation. Thus, four OPERABLE channels are required to satisfy the requirements with two-out-of-four logic (the Environmental Allowance Modifier (EAM) ~~and Trip Time Delay (TTD)~~ function~~s~~ also uses a two-out-of-four logic). Two-out-of-four low level signals in any SG starts the motor-driven AFW pumps; in two SGs starts the turbine-driven AFW pump. As discussed in Reference 11, the SG Water Level - Low Low trip Function has been modified to allow a lower Trip Setpoint under normal containment environmental conditions. ~~and a delayed trip when THERMAL POWER is less than or equal to 22.41% RTP.~~

The EAM~~/TTD~~ circuitry reduces the potential for inadvertent trips via the EAM, enabled on containment pressure exceeding its setpoint ~~and the TTD, enabling time delays dependent on vessel ΔT~~ as listed in Table B 3.3.2-1. Because the SG Water Level transmitters (d/p cells) are located inside containment, they may experience adverse environmental conditions due to a feedline break. The EAM function is used to monitor the presence of adverse containment conditions (elevated pressure) and enables the Steam Generator Water Level - Low Low (Adverse) trip setpoint to reflect the increased transmitter uncertainties due to this harsh environment. The EAM enables a lower Steam Generator Water Level - Low Low

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

d. Auxiliary Feedwater - Steam Generator Water Level - Low Low (continued)

(Normal) trip setpoint when these conditions are not present, thus allowing more margin to trip for normal operating conditions. ~~The TTD delays AFW actuation on SG Water Level - Low Low, thereby providing additional operational margin during early power ascension by allowing the operator time to recover level when the primary side load is sufficiently small to not require an earlier actuation. The TTD continuously monitors primary side power using Vessel ΔT. Scaling of the Vessel ΔT channels is dependent on the loop specific values for ΔT_0, discussed under the OTΔT and OPΔT trips. Two time delays are provided, based on the primary side power level; the magnitude of the trip delay decreases with increasing power.~~ If the EAM ~~or TTD~~ trip function~~s have~~ has inoperable required channels, it is acceptable to place the inoperable channels in the tripped condition and continue operation. Placing the inoperable channels in the trip mode enables the Steam Generator Water Level - Low Low (Adverse) Function, for the EAM, ~~or removes the trip delay for the TTD.~~ If the Steam Generator Water Level - Low Low (Normal) trip Function has an inoperable required channel, the inoperable channel must be tripped, subject to the LCO Applicability footnote.

The Trip Setpoint reflects the inclusion of both steady state and adverse environment instrument uncertainties. The Trip Setpoints for the SG Water Level - Low Low (Adverse Containment Environment) and (Normal Containment Environment) bistables are ~~≥ 27.0% and ≥ 21.6%~~ ≥21.0% and ≥17.0% of narrow range span, respectively. ~~The Trip Setpoints for the Vessel ΔT (Power-1) and (Power-2) bistables are ≤ Vessel ΔT Equivalent to 12.41% RTP and ≤ Vessel ΔT Equivalent to 22.41% RTP, respectively, with corresponding trip time delays of ≤ 232 seconds and ≤ 122 seconds.~~ The Trip Setpoint for the Containment Pressure - Environmental Allowance Modifier bistables is ≤ 1.5 psig.

e. Auxiliary Feedwater - Safety Injection

An SI signal starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

e. Auxiliary Feedwater - Safety Injection (continued)

repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

f. Auxiliary Feedwater - Loss of Offsite Power

The loss of offsite power (LOP) is detected by a voltage drop on each ESF bus. The LOP is sensed and processed by the circuitry for LOP DG Start (Load Shedder and Emergency Load Sequencer) and fed to BOP ESFAS by relay actuation. Loss of power to either ESF bus will start the turbine driven AFW pump, to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip, and automatically isolate the SG blowdown and sample lines. In addition, once the diesel generators are started and up to speed, the motor driven AFW pumps will be sequentially loaded onto the diesel generator buses.

Functions 6.a through 6.f must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. ~~except Function 6.d.(3) which must be OPERABLE in only MODES 1 and 2. Vessel ΔT is used to limit the allowed trip time delay only when greater than 12.41% RTP. Below 12.41% RTP the maximum time delay is permitted; therefore, no OPERABILITY requirements should be imposed on the Vessel ΔT channels in MODE 3.~~ SG Water Level - Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in any two operating SGs will cause the turbine driven pump to start. The SG Water Level Low-Low (Normal Containment Environment) channels do not provide protection when the Containment Pressure – Environmental Allowance Modifier (EAM) channels in the same protection sets are tripped since that enables the SG Water Level Low-Low (Adverse Containment Environment) channels with a higher water level trip setpoint. As such, the SG Water Level Low-Low (Normal Containment Environment) channels need not be OPERABLE when the Containment Pressure – EAM channels in the same protection sets are tripped, as discussed in a footnote to Table 3.3.2-1. These Functions do not have to be

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

8. Engineered Safety Feature Actuation System Interlocks (continued)

b. Engineered Safety Feature Actuation System Interlocks - Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure - Low and Steam Line Pressure - Low SI signals and the Steam Line Pressure - Low steam line isolation signal (previously discussed). When the Steam Line Pressure - Low steam line isolation signal is manually blocked, a main steam isolation signal on Steam Line Pressure - Negative Rate - High is automatically enabled.

This provides protection for an SLB by closure of the MSIVs. With two-out-of-three pressurizer pressure channels above the P-11 setpoint, the Pressurizer Pressure - Low and Steam Line Pressure - Low SI signals and the Steam Line Pressure - Low steam line isolation signal are automatically enabled. The operator can also enable these trips by use of the respective manual unblock (reset) buttons. When the Steam Line Pressure - Low steam line isolation signal is enabled, the main steam isolation on Steam Line Pressure - Negative Rate - High is disabled. The Trip Setpoint reflects only steady state instrument uncertainties. The Trip Setpoint is ≤ 1970 psig.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

9. Automatic Pressurizer PORV Actuation

For the inadvertent ECCS actuation at power event (a Condition II event), the safety analysis (Ref. 15) credits operator actions from the main control room to terminate flow from the normal charging pump (NCP) and to open both ~~at least one~~ PORV block valves (assumed to initially be closed) and assure the availability of ~~the~~ at least one PORV for automatic pressure relief. Analysis results indicate that

(continued)

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ACTIONS

K.1, K.2, K.3.1, and K.3.2 (continued)

suction valves and, after meeting the sump suction valve open position interlock, the RWST RHR suction valves would close. The 72 hour restoration time for an inoperable channel is consistent with that given in other Technical Specifications affecting RHR operability, e.g., for one ECCS train inoperable and for one diesel generator inoperable.

The Completion Times are justified in Reference 8. If the channel cannot be placed in the tripped condition within 6 hours and returned to OPERABLE status within 72 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The Required Actions are modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 4 hours for surveillance testing of other channels. This bypass allowance is justified in Reference 8.

L.1, L.2.1, and L.2.2

Condition L applies to the P-11 interlock.

With one or more required channel(s) inoperable, the operator must verify that the interlock is in the required state for the existing unit condition by observation of the associated permissive annunciator window. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

~~M.1 and M.2~~

~~Condition M applies to the Trip Time Delay (TTD) circuitry enabled for the~~

(continued)

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M.1 and M.2 ~~(continued)~~

Not used.

~~SG Water Level-Low Low trip Functions when THERMAL POWER is less than or equal to 22.41% RTP in MODES 1 and 2. With one or more Vessel ΔT Equivalent (Power-1, Power-2) channel(s) inoperable, the associated Vessel ΔT channel(s) must be placed in the tripped condition within 6 hours. If the inoperability impacts the Power-1 and Power-2 portions of the TTD circuitry (e.g., Vessel ΔT RTD failure), both the Power-1 and Power-2 bistables in the affected protection set(s) are placed in the tripped condition. However, if the inoperability is limited to either the Power-1 or Power-2 portion of the TTD circuitry, only the corresponding Power-1 or Power-2 bistable in the affected protection set(s) is placed in the tripped condition. With one or more TTD circuity delay timer(s) inoperable, both the Vessel ΔT (Power-1) and Vessel ΔT (Power-2) channels are tripped. This automatically enables a zero time delay for that protection channel with either the normal or adverse containment environment level bistable enabled. The Completion Time of 6 hours is based on Reference 11. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. The unit must be placed in MODE 3 within an additional six hours.~~

N.1, N.2.1, and N.2.2

Condition N applies to the Environmental Allowance Modifier (EAM) circuitry for the SG Water Level-Low Low trip Functions in MODES 1, 2, and 3. With one or more EAM channel(s) inoperable, they must be placed in the tripped condition within 6 hours. Placing an EAM channel in trip automatically enables the SG Water Level-Low Low (Adverse Containment Environment) bistable for that protection channel, with its higher SG level Trip Setpoint (a higher trip setpoint means a feedwater isolation or an AFW actuation would occur sooner). The Completion Time of 6 hours is based on Reference 11. If the inoperable channel cannot be placed in the tripped condition within the specified Completion Time, the unit must be placed in a MODE where this Function is not required to be OPERABLE. The unit must be placed in MODE 3 within an additional six hours and in MODE 4 within the following six hours.

O.1 and O.2

Condition O applies to the Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low trip Function. The Condensate Storage Tank is the highly reliable and preferred suction source for the AFW pumps. This

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.9 (continued)

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable. This does not include verification of time delay relays. These are verified via response time testing per SR 3.3.2.10.

~~Whenever an RTD is replaced in Function 5.e.(3) or 6.d.(3), the next required CHANNEL CALIBRATION of the RTDs is accomplished by an inplace cross-calibration that compares the other sensing elements with the recently installed sensing element.~~

The portion of the automatic PORV actuation circuitry required for COMS is calibrated in accordance with SR 3.4.12.9.

SR 3.3.2.10

This SR verifies the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response time verification acceptance criteria are included in Reference 9. No credit was taken in the safety analyses for those channels with response times listed as N.A. No response time testing requirements apply where N.A. is listed in Reference 9. Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position). The safety analyses include the sum of the following response time components:

~~a.~~ ~~Process delay times (e.g., scoop transport delay and thermal lag associated with the narrow range RCS RTDs used in the SG low-low level Vessel ΔT (Power-1, Power-2) functions) which are not testable;~~

a, ~~b.~~ Sensing circuitry delay time from the time the trip setpoint is reached at the sensor until an ESFAS actuation signal is generated by the SSPS (response time testing associated with LSELS and BOP-ESFAS is discussed under SR 3.3.5.4 and SR 3.3.6.6);

(continued)

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SR 3.3.2.10 (continued)

b. ~~c.~~ Any intentional time delay set into the trip circuitry (e.g., ~~NLL cards (lag) and NPL cards (PROM logic cards for trip time delay) associated with the SG low-low level Vessel ΔT (Power-1, Power-2) trip functions;~~ NLL cards (lead/lag) associated with the steam line pressure high negative rate trip function) to add margin or prevent spurious trip signals; and

c. ~~d.~~ The time for the final actuation devices to reach the required functional state (e.g., valve stroke time, pump or fan spin-up time).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time verification is performed with the time constants set at their nominal values. Time constants are verified during the performance of SR 3.3.2.9. The response time may be verified by a series of overlapping tests, or other verification (e.g., Ref. 10 and Ref. 14), such that the entire response time is verified.

Response time may be verified by actual response time tests in any series of sequential, overlapping, or total channel measurements, or by the summation of allocated sensor, signal processing, and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests); (2) inplace, onsite, or offsite (e.g. vendor) test measurements; or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response

Time Testing Requirements," provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," provides the basis and methodology for using allocated signal processing and actuation logic response time in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning, and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in References 10 and 14 may be replaced without verification testing. One example where

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SURVEILLANCE REQUIREMENTS

SR 3.3.2.12 (continued)

opening the PORVs and depressurizing the RCS. If the PORV block valves are closed, there is not enough pressure to open the PORVs.

REFERENCES

1 FSAR, Chapter 6.

2. FSAR, Chapter 7.

3. FSAR, Chapter 15.

4. IEEE-279-1971

5. 10 CFR 50.49.

6. Callaway Setpoint Methodology Report (NSSS), SNP (UE)-565 dated May 1, 1984, and Callaway Instrument Loop Uncertainty Estimates (BOP), J-U-GEN.

7. Not used.

8. Callaway OL Amendment No. 64 dated October 9, 1991.

9. FSAR Section 16.3, Table 16.3-2.

10. WCAP-13632-P-A, Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements," January 1996.

Callaway OL Amendment No. 43 dated April 14, 1989.

12. SLNRC 84-0038 dated February 27, 1984.

13. Callaway OL Amendment No. 117 dated October 1, 1996.

14. WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests," October 1998.

15. FSAR, Section 15.5.1

16. FSAR, Section 15.6.1

17. Letter from Mel Gray (NRC) to Garry L. Randolph (UE), "Revision 20 of the Inservice Testing Program for Callaway Plant, Unit 1 (TAC No. MA4469)," dated March 19, 1999.

18. Westinghouse letter SCP-04-90 dated August 27, 2004

19. ULNRC-03748 dated February 27, 1998.

Table B 3.3.2-1
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FUNCTION			NOMINAL TRIP SETPOINT [a]
5.	Turbine Trip and Feedwater Isolation		
	a.	Automatic Actuation Logic and Actuation Relays (SSPS)	
	b.	Automatic Actuation Logic and Actuation Relays (MSFIS)	
	c.	SG Water Level - High High (P-14)	≤ ~~78%~~ 91.0% of narrow range instrument span
	d.	Safety Injection	See Function 1 (Safety Injection).
	e.	SG Water Level Low-Low	See Function 6.d, SG Water Level Low-Low.
6.	Auxiliary Feedwater		
	a.	Manual Initiation	
	b.	Automatic Actuation Logic and Actuation Relays (SSPS)	
	c.	Automatic Actuation Logic and Actuation Relays (BOP ESFAS)	
	d.	SG Water Level - Low Low	
		(1) Steam Generator Water Level - Low Low (Adverse Containment Environment)	≥ ~~27.0%~~ 21.0% of narrow range instrument span

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

Table B 3.3.2-1
(Page 4 of 5)

		FUNCTION	NOMINAL TRIP SETPOINT [(a)]
d		SG Water Level - Low Low (continued)	
	(2)	Steam Generator Water Level - Low Low (Normal Containment Environment)	≥ ~~21.6%~~ 17.0% of narrow range instrument span
	(3)	~~Vessel ΔT Equivalent including delay timers Trip Time Delay~~ Not used.	
		~~Vessel ΔT (Power-1)~~	~~≤ Vessel ΔT Equivalent to 12.41% RTP (with a time delay ≤ 232 sec.)~~
		~~Vessel ΔT (Power-2)~~	~~≤ Vessel ΔT Equivalent to 22.41% RTP (with a time delay ≤ 122 sec.)~~
	(4)	Containment Pressure - Environmental Allowance Modifier	≤ 1.5 psig
e.		Safety Injection	See Function 1 (Safety Injection).
f.		Loss of Offsite Power	N.A.
g.		Trip of all Main Feedwater Pumps	N.A.
h.		Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low	≥ 21.71 psia

(continued)

(a) The inequality sign only indicates conservative direction. The as-left value will be within a two-sided calibration tolerance band on either side of the nominal value.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Insertion Limits;" LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

The pressurizer pressure limit of ~~2220~~ 2223 psig and the RCS average temperature limit of ~~592.6°F~~ 590.1°F correspond to analytical limits of ~~2202~~ 2205 psig and ~~595.2°F~~ 592.7°F used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

The RCS total flow rate limit contains a measurement error of ~~2.2%~~ 2.1% based on performing a precision heat balance and using the result to normalize the RCS flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner. The RTDP thermal hydraulic analyses assume an RCS flow measurement uncertainty of 2.1% and a total RCS minimum measured flow of 382,630 gpm. Any fouling that might bias the flow rate measurement can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling.

The LCO numerical values for pressure, temperature, and flow rate have been adjusted for instrument error.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

conservatively bound lower modes of operation. The events which assume only two RCPs in operation include the uncontrolled RCCA bank withdrawal from subcritical and the hot zero power rod ejection events. While all accident/safety analyses performed at full rated thermal power assume that all the RCS loops are in operation, selected events examine the effects resulting from a loss of RCP operation. These include the complete and partial loss of forced RCS flow, RCP locked rotor, and RCP shaft break events. For each of these events, it is demonstrated that all the applicable safety criteria are satisfied. For the remaining accident/safety analyses, operation of all four RCS loops during the transient up to the time of reactor trip is assumed thereby ensuring that all the applicable acceptance criteria are satisfied. Those transients analyzed beyond the time of reactor trip were examined assuming that a loss of offsite power occurs which results in the RCPs coasting down.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the limit values, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP and an OPERABLE SG. ~~in accordance with the Steam Generator Tube Surveillance Program.~~ An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow.

APPLICABILITY

In MODES 1 and 2, the reactor, when critical, has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

(continued)

BASES

LCO (continued)

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, ~~in accordance with the Steam Generator Tube Surveillance Program,~~ which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with the Rod Control System capable of rod withdrawal. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the Rod Control System not capable of rod withdrawal.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

(continued)

BASES

ACTIONS

D.1, D.2, and D.3 (continued)

sets). All operations involving introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and defeating the Rod Control System removes the possibility of an inadvertent rod withdrawal. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation, consistent with Required Action C.1 of LCO 3.3.9, "Boron Dilution Mitigation System (BDMS)." The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

7%

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 4% for required RCS loops. If the SG secondary side narrow range water level is < 4%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

(continued)

BASES (continued)

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be removed from operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the necessary testing, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature ≤ 275°F. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop is comprised of an OPERABLE RCP and an OPERABLE SG, ~~in accordance with the Steam Generator Tube Surveillance Program,~~ which has the minimum water level specified in SR 3.4.6.2.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS or RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation from at least one

RCP for proper mixing so that inadvertent criticality can be prevented. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation, consistent with Required Action C.1 of LCO 3.3.9, "Boron Dilution Mitigation System (BDMS)." The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.2 7%

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 4% for required RCS loops. If the SG secondary side narrow range water level is < 4%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer of this heat either to the steam generator (SG) secondary side coolant via natural circulation (Ref. 1) or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs via natural circulation are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification but is not sufficient for the boron dilution analysis discussed below.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side wide range water levels above 86% ~~66%~~ to provide an alternate method for decay heat removal via natural circulation.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event.

The operation of one RCP in MODES 3, 4, and 5 provides adequate flow to ensure mixing, prevent stratification, and produce gradual reactivity changes during RCS boron concentration reductions. The reactivity change rate associated with boron reduction will, therefore, be within the transient mitigation capability of the Boron Dilution Mitigation System (BDMS). With no reactor coolant loop in operation in either MODES 3, 4, or 5, boron dilutions must be terminated and dilution sources isolated. The boron dilution analysis in these MODES takes credit for the mixing volume associated with having at least one reactor coolant loop in operation. LCO 3.3.9, "Boron Dilution Mitigation System (BDMS)," contains the requirements for the BDMS.

RCS Loops - MODE 5 (Loops Filled) satisfies Criterion 4 of 10CFR50.36(c)(2)(ii).

86%

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side wide range water level ≥ 66%. As shown in Reference 3, any narrow range level indication above 4% will ensure the SG tubes are covered. One RHR loop provides sufficient forced 7% circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side wide range water levels ≥ 66%. Should the operating RHR loop fail, the SGs could be used to remove the decay heat via natural circulation.

86%

Note 1 permits all RHR pumps to be removed from operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests that are required to be performed without flow or pump noise. The 1 hour time period is adequate to perform the necessary testing, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by test procedures:

(continued)

BASES (continued)

LCO (continued)

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation. Boron dilution with coolant at boron concentrations less than required to assure the SDM is maintained is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 3 requires that the secondary side water temperature of each SG be $\leq$ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with any RCS cold leg temperature $\leq$ 275°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. ~~An OPERABLE~~ A SG 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 Tube Surveillance Program.~~

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side wide range water level of at least two SGs is required to be $\geq$ ~~66%.~~ 86%.

(continued)

BASES (continued)

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level" (MODE 6); and
LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

86%

If one RHR loop is inoperable and the required SGs have secondary side wide range water levels < 66%, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Notes 1 and 4, or if no loop is OPERABLE, all operations involving introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent inadvertent criticality during a boron dilution, forced circulation from at least one RCP is required to provide proper mixing. Suspending the introduction of coolant, into the RCS, with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to subcritical operations. Introduction of reactor makeup water into the RCS from the Chemical and Volume Control System mixing tee is not permitted when no RCS loop is in operation, consistent with Required Action C.1 of LCO 3.3.9, "Boron Dilution Mitigation System (BDMS)." The immediate Completion Times reflect the importance of maintaining operation for heat removal.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification may include flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

86%

Verifying that at least two SGs are OPERABLE by ensuring their secondary side wide range water levels are ≥ [illegible] ensures an alternate decay heat removal method is available via natural circulation in the event that the second RHR loop is not OPERABLE. As shown in Reference 3, any narrow range level indication above [illegible] will ensure the SG tubes are covered. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

7%

SR 3.4.7.3

86%

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side wide range water level is ≥ [illegible] in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1 NRC Information Notice 95-35, "Degraded Ability of SGs to Remove Decay Heat by Natural Circulation."

2 FSAR Section 15.4.6.

3. TDB-001, "Tank Data Book, Steam Generators EBB01 (A,B,C,D)."

BASES

BACKGROUND (continued)

undervoltage signal and manually sequenced back onto the Class 1E 4.16-kV buses.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the FSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The ~~maximum pressurizer water level limit, which ensures that a~~ presence of a steam bubble ~~exists~~ in the pressurizer (assured by the pressurizer level control program) satisfies Criterion 2 of 10CFR50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume $\leq$ 1657 cubic feet, which is equivalent to 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is ~~also~~ consistent with analytical assumptions.

The LCO requires two groups of OPERABLE backup pressurizer heaters, each with a capacity $\geq$ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The backup pressurizer heaters may be controlled from either the main control board or the auxiliary shutdown panel.

(continued)

BASES (continued)

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is the need to maintain the availability of pressurizer heaters, capable of being powered from either the offsite power source or the emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1, A.2, A.3, and A.4

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the ~~nominal upper~~ LCO limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the ~~upper limit of this~~ LCO limit is the same as the Pressurizer Water Level - High Trip.

If the pressurizer water level is not within the limit, action must be taken to bring the plant to a MODE in which the LCO does not apply. To achieve this status, within 6 hours the unit must be brought to MODE 3, with all rods fully inserted and incapable of withdrawal (e.g., by de-energizing all CRDMs, by opening the RTBs, or de-energizing the motor generator (MG) sets). Additionally, the unit must be brought to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

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

B.1

If one required group of backup pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss

(continued)

BASES

ACTIONS

B.1 (continued)

of offsite power would be unlikely in this period. Pressure control may be maintained during this time using the remaining OPERABLE backup pressurizer heater group or the variable heater group.

C.1 and C.2

If one group of backup pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

LCO

This SR requires that during steady state operation, pressurizer level is maintained below the ~~nominal upper~~ limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is consistent with the safety analyses assumption of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated backup pressurizer heaters are verified to be at their design rating. This is done by energizing the heaters and measuring circuit current. The Frequency of 18 months is considered adequate to detect heater degradation.

REFERENCES

1. FSAR, Chapter 15.

2. NUREG-0737, November 1980.

BASES

BACKGROUND (continued)

The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal at full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load/turbine trip;

d. Loss of normal feedwater;

e. Loss of non-emergency AC power to station auxiliaries;

f. Locked rotor;

g. Feedwater line break; and

h. Rod cluster control assembly ejection.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation occurs in the FSAR Chapter 15 analysis of events ~~c, f, and g~~ c and f (above) and may be required for any of the above events to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at 2460 psig (slightly below the RCS design pressure of 2485 psig), and within the specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the tolerance requirements assumed in the safety analyses.

(continued)

BASES

BACKGROUND (continued)

overpressure mitigation. See LCO 3.4.12, "Cold Overpressure Mitigation System (COMS)."

APPLICABLE SAFETY ANALYSES

Plant operators may employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

For the inadvertent ECCS actuation at power event (a Condition II event), the safety analysis (Ref. 1) credits operator actions from the main control room to terminate flow from the normal charging pump (NCP) and to open both ~~a~~ PORV block valves (assumed to initially be closed) ~~and~~ to assure the availability of at least one PORV for automatic pressure relief. Analysis results indicate that water relief through the pressurizer safety valves, which could result in the Condition II event degrading into a Condition III event if the safety valves did not reseat, is precluded if operator actions are taken within the times assumed in the Reference 1 analysis to terminate NCP flow and to assure at least one PORV is available for automatic pressure relief. The assumed operator action times conservatively bound the times measured during simulator exercises. Therefore, automatic PORV operation is an assumed safety function in MODES 1, 2, and 3. The PORVs are equipped with automatic actuation circuitry and manual control capability. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions (Ref. 1) to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic operation position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator actions.

The PORVs are also modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR), pressurizer volume, or hot leg saturation criteria are examined (Ref. 3). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint. The DNBR calculation is more conservative, the pressurizer water volume is maximized, and the hot leg saturation temperature is reduced for those transients assuming

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PORV operation. Events that assume this condition include turbine trip, loss of normal feedwater, loss of non-emergency AC power to station auxiliaries, and ~~the~~ feedline break ~~case with no SI~~ (Ref. 3). Automatic operation is assumed in the Reference 3 analyses , but operation of the PORVs has a detrimental impact on the results of the analysis.

Pressurizer PORVs satisfy Criterion 3 of 10CFR50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

The LCO also requires the PORVs and their automatic actuation circuitry to be OPERABLE, in conjunction with the capability to manually open their associated block valves and assure the availability of the PORVs for automatic pressure relief, to mitigate the effects associated with an inadvertent ECCS actuation at power event. The PORVs are considered OPERABLE in either the automatic or manual mode, as long as the automatic actuation circuitry is OPERABLE and the PORVs can be made available for automatic pressure relief by timely operator actions (Ref. 1) to open the associated block valves (if closed) and assure the PORV handswitches are in the automatic operation position. The automatic mode is the preferred configuration, as this provides the required pressure relieving capability without reliance on operator actions.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized, or closed and energized, with the capability to be cycled, since the required safety functions of the block valve are accomplished by manual operation to cycle the block valve. Although typically open to allow PORV operation, the block valve may be OPERABLE when closed to isolate the flow path of an inoperable PORV because of excessive seat leakage. Isolation of an OPERABLE PORV does not render that PORV or block valve inoperable, provided the automatic pressure relief function remains available with timely operator actions (Ref. 1) to open the associated block valve, if closed, and assure the PORV's handswitch is in the automatic operation position. Satisfying the LCO helps minimize challenges to fission product barriers and precludes water relief through the pressurizer safety valves.

An OPERABLE PORV must not be experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criterion, exists when conditions dictate closure of the block valve to limit leakage.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can allow varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.
RCS Operational

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.
Operational

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Except for RCS primary to secondary LEAKAGE, the safety analyses do not address RCS operational LEAKAGE. However, the other forms of RCS ~~other~~ operational LEAKAGE ~~is~~ are related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analyses for events resulting in steam discharge to the atmosphere assume ~~a 1 gpm primary to secondary LEAKAGE as an initial condition.~~ INSERT B 3.4.13A

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. Other accidents or transients involving secondary steam release to the atmosphere include the steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 3) analysis for SGTR assumes the contaminated secondary fluid is released via ~~atmospheric relief valves.~~ a postulated stuck-open atmospheric steam dump (ASD) valve or a partially stuck-open main steam safety valve.

The safety analysis for the SLB accident assumes 1 gpm primary to secondary LEAKAGE in ~~one~~ the affected generator as an initial condition. The dose consequences resulting from the SLB and SGTR accidents are well within the limits defined in 10 CFR 100 (Ref. 5) (i.e., a small fraction of these limits).

The safety analysis for RCS main loop piping for GDC-4 (Ref. 1) assumes 1 gpm unidentified leakage and monitoring per RG 1.45 (Ref. 2) are maintained (Ref. 4).

The RCS operational LEAKAGE satisfies Criterion 2 of 10CFR50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals, gaskets, and instrumentation lines is not pressure boundary LEAKAGE. Instrumentation lines are 3/8 inch tubing for instrument connections to ASME Class 1 fluid piping downstream of the root valves and 1/8 inch core exit thermocouple sheaths. These instrument lines are not part of the reactor coolant pressure boundary (RCPB) nor do they provide a pressure retaining barrier.

(continued)

INSERT B 3.4.13 A

that primary to secondary LEAKAGE through all steam generators (SGs) is one gallon per minute. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 150 gallons per day is significantly less than the conditions assumed in the safety analyses.

BASES

LCO

a. Pressure Boundary LEAKAGE (continued)

Normal charging can accommodate a 3/8 inch break and maintain normal pressurizer level such that the ECCS is not actuated.

b. Unidentified LEAKAGE

leak

in LCO 3.4.15, "RCS Leakage Detection Instrumentation,"

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

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

~~d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)~~

~~Total primary to secondary LEAKAGE amounting to 1 gpm through all SGs produces acceptable offsite doses in the accident analyses involving secondary steam discharge to the atmosphere. Violation of this leakage rate could exceed the offsite dose limits for these accidents. Per Reference 6 and SG tube integrity considerations, the LCO is set lower at 600 gallons per day through all SGs. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE~~

d. ~~e.~~ Primary to Secondary LEAKAGE through Any One SG

~~The 150 gallons per day limit on one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a~~

INSERT B 3.4.13B

(continued)

INSERT B 3.4.13 B

d. Primary to Secondary LEAKAGE Through Any One SG

The limit of 150 gallons per day per SG is based on Reference 6 and the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 7). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, "The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day." The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

BASES

LCO

e. ~~Primary to Secondary LEAKAGE through Any One SG (continued)~~

~~main steam line rupture. If leaked through many cracks, the cracks are very small, and the above assumption is conservative.~~

APPLICABILITY

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

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

LCO 3.4.14, "RCS Pressure Isolation Valve (PIV) Leakage," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

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

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if primary to secondary LEAKAGE is not within limit, or if unidentified LEAKAGE ~~,~~ or identified LEAKAGE ~~, or primary to secondary LEAKAGE~~ cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals, gaskets, and instrumentation lines is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Operational

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

SR 3.4.13.1 is modified by two Notes.

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

Note 1 states

Steady state operation is preferred to perform a proper inventory balance since calculations during non-steady state conditions must account for the changing parameters. ~~For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.~~

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals, gaskets, and instrumentation lines is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

particulate

(continued)

INSERT B 3.4.13C

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

SR 3.4.13.2

INSERT B3.4.13D

~~This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions. This surveillance does not tie directly to any of the leakage criteria in the LCO or to the CONDITIONS; therefore, failure to meet this surveillance is considered failure to meet the integrity goals of the LCO and LCO 3.0.3 applies.~~

REFERENCES

1. 10 CFR 50, Appendix A, GDC 4 and 30.
2. Regulatory Guide 1.45, May 1973.
3. FSAR, Section 15.6.3.
4. NUREG-1061, Volume 3, November 1984.
5. 10 CFR 100.
6. Amendment No. 116 dated October 1, 1996.

INSERT B 3.4.13E

INSERT B 3.4.13 C

Note 2 states that SR 3.4.13.1 is not applicable to primary to secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

INSERT B 3.4.13 D

This SR verifies that primary to secondary LEAKAGE is less or equal to 150 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17, "Steam Generator Tube Integrity," should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Reference 8. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

SR 3.4.13.2 is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary to secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. During normal operation the primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling. In MODES 3 and 4, the primary system radioactivity level may be very low, making it difficult to measure primary to secondary LEAKAGE. If SG water samples are less than the minimum detectable activity for each principal gamma emitter, primary to secondary LEAKAGE may be assumed to be less than 150 gallons per day through any one SG (Ref. 8).

INSERT B 3.4.13 E

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

8. EPRI TR-104788, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1 (continued)

MODE 3 with T_{avg} at least 500°F. The 7 day Frequency considers the unlikelihood of a gross fuel failure during the time.

SR 3.4.16.2

This Surveillance is performed to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering gross activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results. The Note modifies this SR to allow entry into and operation in MODE 2 and in MODE 3 with T_{avg} ≥ 500°F prior to performing the SR. This allows the surveillance to be performed in those MODES, prior to entering MODE 1.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Frequency of 184 days recognizes $\bar{E}$ does not change rapidly.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1 10 CFR 100.11, 1973.

2 FSAR, Section 15.6.3

→ INSERT NEW LCO 3.4.17 BASES (next 7 pages)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

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

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

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity; accident induced leakage; and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

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

BASES (continued)

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a primary to secondary LEAKAGE rate of 1 gpm to the unaffected steam generators, in excess of the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is released to the atmosphere via a postulated stuck-open atmospheric steam dump (ASD) valve or via a partially stuck-open main steam safety valve (see Ref. 2).

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 1 gallon per minute. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 3), 10 CFR 100 (Ref. 4) or the NRC approved licensing basis (e.g., a small fraction of these limits).

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

LCO

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

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

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

BASES

LCO (continued)

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

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

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as the gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation. Tube collapse is defined as follows: For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero. The structural integrity performance criterion provides guidance on assessing loads that significantly affect burst or collapse. In that context, the term significant is defined as follows: An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established. The determination of whether thermal loads are primary or secondary loads is based on the ASME definition in which secondary loads are self-limiting and will not cause failure under single load application. For steam generator tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

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

BASES

LCO (continued)

III, Subsection NB (Ref. 5) and Draft Regulatory Guide 1.121 (Ref. 6).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm total for all four steam generators. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

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

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged in accordance with the Steam Generator

BASES

A.1 and A.2 (continued)

Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

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

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI

BASES

SR 3.4.17.1 (continued)

Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

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

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

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 7). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.17.2

During a SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is removed from service by plugging. The tube repair criteria delineated in Specification 5.5.9 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 and Reference 7 provide guidance for performing operational assessments to verify that the tubes

BASES

SR 3.4.17.2 (continued)

remaining in service will continue to meet the SG performance criteria.

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

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. FSAR Section 15.6.3
3. 10 CFR 50 Appendix A, GDC 19.
4. 10 CFR 100.
5. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
6. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
7. EPRI TR-107569, "Pressurized Water Reactor Steam Generator Examination Guidelines."

BASES

APPLICABLE SAFETY ANALYSES (continued)

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated primarily by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and centrifugal charging pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the centrifugal charging pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators empty themselves by the beginning stages of the reflood phase of a large break LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. For small breaks, an increase in water volume is a peak clad temperature penalty. For large breaks, an increase in water volume can be either a peak clad temperature penalty or benefit, depending on downcomer filling and subsequent spill through the break during the core reflooding portion of the transient. The analysis makes a conservative assumption with respect to ignoring ~~or taking credit for~~ the line water volume from the accumulator to the check valve. Values of 6061 gallons and 6655 gallons are specified.

(continued)

BASES

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves"

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. All equipment hatches are closed and sealed; and

d. The sealing mechanism associated with each penetration (e.g. welds, bellows, or O-rings) is OPERABLE.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA) and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.2% of containment air weight per day for the first 24 hours and 0.1% of containment air weight per day for the remainder of the accident (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting design bases LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.2% of containment air weight per day ~~in the safety analysis~~ at P_a = 48.1 psig, ~~(Ref. 3).~~ This is a conservative value for P_a since the calculated peak containment pressure for LOCA is 46.25 psig. Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

The personnel air lock is nominally a right circular cylinder, approximately 10 ft in diameter, with a door at each end. The emergency air lock is approximately 5 ft 9 in inside diameter with a 2 ft 6 in door at each end. On both air locks, doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure sealed doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide local indication of door position.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analyses.

APPLICABLE SAFETY ANALYSES

The DBA that result in a release of radioactive material within containment is a loss of coolant accident (Ref. 2). In the analysis of this accident, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.2% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B, (Ref. 1) L_a as the maximum allowable containment leakage rate at the calculated peak containment internal pressure, P_a = 48.1 psig following a design basis LOCA. This

(See the Applicable Safety Analyses Bases for LCO 3.6.1, "Containment.")

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or main steam line break (MSLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and MSLB, which are analyzed using computer codes developed to predict the containment pressure transients. The worst case MSLB generates larger mass and energy release than the worst case LOCA. Thus, the MSLB event bounds the LOCA event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 14.7 psia (0.0 psig). This resulted in a calculated ~~maximum~~ peak pressure from a MSLB of ~~48.1~~ 44.8 psig. The containment analysis ~~(Ref. 1)~~ shows that the ~~maximum~~ peak calculated containment pressure, P_a, results from the limiting ~~MSLB.~~ LOCA. The ~~maximum~~ calculated containment pressure resulting from the worst case LOCA, ~~47.3~~ 46.25 psig, does not exceed the containment design pressure, 60 psig.

P_a, as specified in Administrative Control Specification 5.5.16.b, will be left at 48.1 psig. Design basis evaluations will continue to cite this value and the peak pressure reported in the FSAR will continue to be 48.1 psig.

The containment was also designed for an external pressure load equivalent to -3 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure. The initial pressure condition used in this analysis was 14.7 psia. This resulted in a minimum pressure inside containment of -2.72 psig, which is less than the design load.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or main steam line break (MSLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and MSLB. The DBA LOCA and MSLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the ~~loss of one ESF bus, which is the~~ worst case single active failure, ~~resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.~~ A spectrum of MSLBs was analyzed, ~~assuming the worst single active failure.~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBA for the maximum peak containment air temperature is an MSLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 120°F. This resulted in a maximum calculated containment air temperature of ~~384.9°F.~~ 352.8°F (assuming the failure of an MSIV to close). Design basis evaluations will continue to cite 384.9°F and the peak temperature reported in the FSAR will continue to be 384.9°F. The design temperature is 320°F.

The spectrum of MSLBs cases are used to establish the environmental qualification operating envelope for containment. The performance of required safety-related equipment, including the containment structure itself, is evaluated against this operating envelope to ensure the equipment can perform its safety function. The maximum peak containment air temperature was calculated to exceed the containment design temperature for only a few seconds during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the equipment surface temperatures remained below the design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA MSLB (Ref. 3).

The temperature limit is also used in the Containment external pressure analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System (Ref. 1).

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a MSLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the maximum containment temperature analyzed in Ref. 3. As a result, the ability of containment to perform its design function is ensured.

(continued)

BASES

BACKGROUND

Containment Cooling System (continued)

with the Containment Ventilation system, is designed to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically in slow speed if not already running. If running in high (normal) speed, the fans automatically shift to slow speed. The fans are operated at the lower speed during accident conditions to prevent motor overload from the higher mass atmosphere. The temperature of the ESW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limits the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest ~~peak~~ calculated containment pressure is ~~48.1~~ 46.25 psig (experienced during a LOCA ~~SLB~~). The analysis shows that the calculated ~~peak~~ containment temperature is 352.8°F ~~384.9°F~~ (experienced during an SLB). Both results meet the intent of the design basis which is evaluated against peak values of 48.1 psig and 384.9°F as reported in the FSAR. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level of 102%, one containment spray train and one containment cooling train operating, and initial (pre-accident) containment conditions of 120°F and 0 psig. The analyses assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment

(continued)

BASES (continued)

APPLICABILITY	In MODES 1, 2, and 3, five MSSVs per steam generator are required to be OPERABLE to limit secondary system pressure. In MODES 4, 5 and 6 there are no credible transients requiring the MSSVs.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

<u>A.1</u>

In the case of only a single inoperable MSSV on one or more steam generators when the Moderator Temperature Coefficient is not positive a reactor power reduction alone is sufficient to limit primary side heat generation such that overpressurization of the secondary side is precluded for any RCS heatup event. Furthermore, for this case there is sufficient total steam flow capacity provided by the turbine and remaining insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Therefore, Required Action A.1 requires an appropriate reduction in reactor power within 4 hours. Required Action A.1 is only applicable when the Moderator Temperature Coefficient is negative at all power levels.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to References 6 and 7, with an appropriate allowance for calorimetric power uncertainty.

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

Continued operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

B.1 and B.2

In the case of multiple inoperable MSSVS on one or more steam generators, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program (Ref. 5).

The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a +3%/-1% setpoint tolerance for OPERABILITY; however, the valves are reset to $\pm$ 1% during the Surveillance to allow for drift. The liftsettings pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected, if necessary, to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1 FSAR, Section 10.3.2, Main Steam Supply System - System Description.

2. ASME, Boiler and Pressure Vessel Code, Section III, Article NC-7000, Class 2 Components.

3. FSAR, Section 15.2, Decrease in Heat Removal by the Secondary System.

4. NRC Information Notice 94-60, "Potential Overpressurization of the Main Steam System," August 22, 1994.

5. ASME, Boiler and Pressure Vessel Code, Section XI.

6. Westinghouse Letter SCP-99-129, dated July 7, 1999.

7 WCAP-16215-P, "Callaway Replacement Steam Generator Program NSSS Licensing Report," September 2004.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Condenser Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIV is a 28 inch gate valve with dual-redundant hydraulic actuators. The assumed single failure of one of the redundant actuators will not prevent the MSIV from closing.

The MSIVs close on a main steam isolation signal generated by low steam line pressure, high steam line negative pressure rate or High-2 containment pressure. The MSIVs fail as is on loss of control or actuation power.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the FSAR, Section 6.2.1.4 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the FSAR, Section 15.1.5 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The limiting case for the containment pressure analysis is the ~~SLB~~ LOCA inside containment, with initial reactor power at ~~25%~~ 102% with loss of offsite power and the failure of one emergency diesel generator, ~~(Ref. 6).~~ Because of increased energy storage in the primary plant, increased heat transfer in the steam generators, and the additional energy generation in the nuclear

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is $\leq$ 5.0 seconds from each actuator train when tested pursuant to the Inservice Test Program. The MSIV isolation time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. (space)

The Frequency is in accordance with the Inservice Testing Program.

This test is conducted in MODE 3 with the unit at nominal operating temperature and pressure. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

This SR verifies that each MSIV is capable of closure on an actual or simulated actuation signal. The manual fast close (space) handswitch in the Control Room provides an acceptable actuation signal. This Surveillance is normally performed upon returning the unit to operation following a refueling outage in conjunction with SR 3.7.2.1. However, it is acceptable to perform this surveillance individually. The frequency of MSIV testing is every 18 months. The 18 month Frequency for testing is based on the refueling cycle. This Frequency is acceptable from a reliability standpoint. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those necessary to perform SR 3.7.2.1 and SR 3.7.2.2 concurrently.

REFERENCES

1 FSAR, Section 10.3, Main Steam Supply System.

2. FSAR, Section 6.2, Containment Systems.

(continued)

BASES

BACKGROUND (continued)

valves. The motor driven pumps supply flow to the steam generators through a normally open motor operated valve that automatically throttles flow to prevent pump runout conditions under all steam generator pressure conditions. One pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

(i.e., at the lowest MSSV lift setting plus 3% tolerance).

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the lowest pressure setpoint of the MSSVs plus 3% accumulation. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ASDs.

The motor driven AFW pumps start automatically on steam generator water level - low-low in any steam generator, on trip of both main feedwater pumps, upon actuation of AMSAC, on actuation by the LOCA sequencer and the shutdown sequencer. The turbine driven AFW pump is automatically started by steam generator water level -low-low in any two steam generators, NB01 or NB02 undervoltage, and upon actuation of AMSAC.

The AFW System is discussed in the FSAR, Section 10.4.9 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3% accumulation (tolerance).

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB),

b. Main Steam Line Break; and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Loss of MFW. (begin new ¶ here)

In addition, the minimum available AFW flow and system characteristics are considerations in the analysis of a small break loss of coolant accident (LOCA). The AFW System design is such that it can perform its function following an FWLB between the MFW isolation valves and containment, combined with a loss of offsite power following turbine trip, and a single active failure of one motor driven AFW pump. This results in minimum assumed flow to the intact steam generators. One motor driven AFW pump would deliver to the broken MFW header at a flow rate throttled by the motor operated "smart" discharge valve until the problem was detected, and flow terminated by the operator. Sufficient flow would be delivered to the intact steam generators by the residual flow from the affected pump plus the turbine driven AFW pump (Ref. 5).

INSERT B 3.7.5 A

The BOP ESFAS automatically actuates the ~~AFW~~ turbine driven AFW pump when required to ensure an adequate feedwater supply to the steam generators during loss of power. Air operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of decay heat removal for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps (MDAFPs) be OPERABLE in two diverse paths, each capable of automatically transferring the suction from the CST to an ESW supply line and supplying AFW to two steam generators. The turbine driven AFW pump (TDAFP) is required to be OPERABLE with redundant steam supply lines from each of two main steam lines upstream of theMSIVs, and shall be capable of automatically transferring the suction from the CST to two

(continued)

INSERT B 3.7.5 A

The FSAR Chapter 15 analysis of the Loss of Normal Feedwater (LONF) event (see Reference 7) assumes that both motor-driven AFW pumps provide auxiliary feedwater flow to all four steam generators. The limiting single failure in the analysis of this event is the failure of the turbine-driven AFW pump.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.5.3 (continued)

engineering judgement and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

REFERENCES

1. FSAR, Section 10.4.9, Auxiliary Feedwater System.
2. ASME, Boiler and Pressure Vessel Code, Section XI.
3. FSAR, Section 9.3.1, Compressed Air System.
4. Amendment No. 55 to facility Operating License No. NPF-30, dated 7/27/90.
5. FSAR 15.2.8, Feedwater System Pipe Break.
6. Request for Resolution (RFR) 21816A.
7. WCAP-16265-P, "Callaway Replacement Steam Generator Program NSSS Licensing Report," September ~~August~~ 2004.

ATTACHMENT 5

SUMMARY OF REGULATORY COMMITMENTS

SUMMARY OF REGULATORY COMMITMENTS

The following table identifies those actions committed to by AmerenUE in this document. Any other statements in this submittal are provided for information purposes and are not considered to be commitments. Please direct questions regarding these commitments to Mr. Dave E. Shafer, Superintendent Licensing, (314) 554-3104.

COMMITMENT	Due Date/Event
AmerenUE will adopt the NRC-approved revision of TSTF-449.	Amendment supplement to be submitted, if needed, within 60 days of NRC approval of final revision to TSTF-449
AmerenUE will provide documentation regarding effective mitigation measures to be applied at the Alloy 82/182 pressurizer nozzle safe end weld.	November 30, 2004
A separate amendment application will be submitted to revise Technical Specification 3.7.3 to be consistent with Revision 3 of the STS NUREG 1431, adding the main feedwater control and bypass valves to LCO 3.7.3 with 72 Completion Times in Conditions A, B, and C.	Amendment to be submitted by November 30, 2004
The proposed changes to the Callaway Technical Specifications will be implemented prior to MODE 5 entry ascending during startup from Refuel 14.	Prior to MODE 5 entry ascending during startup from Refuel 14
A separate amendment application will be submitted to revise Technical Specification 3.7.2 if a decision is made to install new MSIV actuators during Refuel 14 that would increase the valve stroke time to 15 seconds. The RSG analyses support this stroke time increase.	Amendment to be submitted by November 30, 2004

NERA-04-0067
September 3, 2004

Dave Shafer:

Subject: Transmittal of WCAP 16265 Open Items for the RSG Project

Attached to this letter is a matrix of AmerenUE open items identified in Westinghouse RSG Licensing Report WCAP 16265. Also included in this matrix are the AmerenUE responses to these items. All open items have been addressed in sufficient detail to support OL Amendment # 1248.

Keith A Mills 03 Sept 04

K. A. Mills
Safety Analysis Supervisor

DEM/KAM: shs

Attachments

cc. T. E. Herrmann
B. E. Huhmann
W. M. Cryderman
A160.0444

OPEN ITEMS FOR CALLAWAY RSGs

ITEM	DESCRIPTION	AUE RESPONSE	STATUS FOR OL-#1248 SUBMITTAL
Pressurizer Water Level	Revise nominal level from linear between 25% at 0% power to 61.5% at 100% power to the following: – linear between 25% at 0% power and the 100% power level defined as follows: 1.2429 * FLTAVG – 671.3 (% of span), where FLTAVG = measured auctioneered high full power Tavg. FLTAVG can range between 570.7°F and 588.4°F.	MP 00-1013 component modification addresses the change in pressurizer programmed level. Plant procedures requiring revision will be identified as part of the modification process.	Closed
Pressurizer Relief Tank (PRT) Setpoints	Revise PRT level alarm setpoints as follows: – at full power Tavg of 588.4°F, with 60% water level: high level alarm setpoint = 80%; low level alarm setpoint = 59% – at full power Tavg of 570.7°F, with 38% water level: high level alarm setpoint = 76%; low level alarm setpoint = 69%	MP 00-1013 component modification addresses the revised PRT alarm setpoints. Plant procedures requiring revision will be identified as part of the modification process.	Closed
Pressurizer Spray Line Low Temperature Alarm Setpoint	Current value is 545°F. With RSG, minimum Tcold temperature could be as low as 538°F. Spray line temperature could be lower than low-temperature alarm setpoint if the setpoint is not lowered. AmerenUE to review possible need to change.	The Pressurizer Spray Line Low Temperature Alarm Setpoint will be revised when Tavg Coastdown is implemented. No changes or LAR discussions are necessary at this time.	Closed
SG Low-Low Water Level Reactor Trip	There is expected to be adequate margin to the low-low SG level setpoint during low power operation, but this depends to some extent on the response of the FW control valves, and the experience of the plant operators when the control system is in manual. AmerenUE should review plant performance data following RSG implementation to determine the amount of margin to the trip setpoint.	This operational issue will be addressed by the SGR Start-up Group.	Closed

OPEN ITEMS FOR CALLAWAY RSGs

ITEM	DESCRIPTION	AUE RESPONSE	STATUS FOR OL-#1248 SUBMITTAL
Full-Power Tavg Operation	Full-power plant operating Tavg would have to be greater than 573°F for the current steam dump setpoints to be adequate to withstand a 50% load rejection transient and reactor trip from full-power transient. Other NSSS areas are acceptable down to 570.7°F. The 573°F limit should not be a problem for the plant since full power will not be achievable at that reduced temperature anyway. AmerenUE should decide whether any procedures need to be put in place.	This issue would be revisited when Tavg Coastdown is implemented. Plant procedures requiring revision would be identified as part of the modification process to implement the change. No changes or LAR discussions are necessary at this time.	Closed
Fuel Assembly Holddown Spring Capability	Assumption made that last reactor coolant pump startup would occur with RCS temperature of 140°F or greater. This is higher than the previous conservative assumption of 70°F and was agreed to by AmerenUE. AmerenUE should determine what procedures, if any, need to be put into place to ensure that the last pump startup temperature is not less than 140°F.	Incorporated prior to RF13 in plant procedure OTN-BB-00003, Rev. 15, Step 2.19.	Closed
Overtemperature and Overpower T Setpoints	AmerenUE has the scope to determine whether any changes are required to the K1 and K4 values for the OT T and OP T setpoint equations in the Technical Specifications.	Based on a review of AmerenUE calculation BB-50, Rev. 1 and addenda, this item is not impacted by the RSG project.	Closed
SG Level Setpoints	Revise Water Level Setpoints as Follows: – High-High protection system setpoint from 78% to 91.0% – Low-Low protection system setpoint from 21.6% (normal), 27.0% (adverse) to 17.0% (normal), 21.0% (adverse) – Nominal control setpoint from constant level of 50.0% to constant level of 51.3%	MP 00-1013 component modification addresses the identified setpoints. Plant procedures requiring revision will be identified as part of the modification process.	Closed

OPEN ITEMS FOR CALLAWAY RSGs

ITEM	DESCRIPTION	AUE RESPONSE	STATUS FOR OL-#1248 SUBMITTAL
Spent Fuel Pool Cooling	The spent fuel pool cooling system is a Bechtel Design. It is not expected that the change in heat loads due to the RSG will exceed the heat load increases that were previously predicted for the Callaway uprate analysis (to 3,579 MWt). Verification should be provided by Bechtel or AmerenUE, since this system is not within the Westinghouse original scope of supply.	MP 00-1013 component modification evaluates the impact on the Essential Service Water System as a result of RSGs.	Closed
SG Blowdown System Control Valves	The minimum full-load steam pressure could be as low as 867 psia or 41 psi lower than the current minimum full-load pressure (908 psia). This decrease in blowdown system inlet pressure will impact the required maximum lift of the blowdown flow control valves. Therefore, the design of the blowdown system control valves must be reviewed by AmerenUE to determine if blowdown flow control is adequate for the range of NSSS design parameters approved for the RSGs.	MP 00-1013 component modification evaluates the blowdown system control valves.	Closed
Reactor Coolant Loop Supports	The data and loadings applied to the building structures were provided to AmerenUE for further evaluation.	MP 00-1013 component modification addresses the follow-up evaluation in the component modification.	Closed
Leak Before Break	The LBB licensing bases were evaluated and were shown to remain valid. The LBB basis for surge line is still being reviewed by the NRC. At this time, that approval is still unclear. If approval is not obtained prior to RSG implementation, some additional work would have to be performed, as discussed in Westinghouse letter SCP-04-43.	Discussed in the commitment section of OL #1248.	Closed

OPEN ITEMS FOR CALLAWAY RSGs

ITEM	DESCRIPTION	AUE RESPONSE	STATUS FOR OL-#1248 SUBMITTAL
Containment Response Analysis	In the original RSG contract, Westinghouse had scope to provide the LOCA and main steam line break mass and energy releases to AmerenUE for further evaluation. Subsequently, AmerenUE contracted Westinghouse to provide the containment response analysis. The containment response analysis is not documented in the RSG Engineering Report, WCAP 16140. The results of the LOCA mass and energy releases are documented in WCAP-16140 Section 6.5. The results of the main steam line break mass and energy releases are documented in WCAP-16140 Section 6.6. The results of the containment response analysis are being documented separately. AmerenUE must incorporate the results into their integrated licensing submittal.	The containment response results have been transmitted to AUE in W letter SCP-04-74. The results are addressed in OL #1248.	Closed
Radiological Consequences	In the original RSG contract, Westinghouse had scope to provide the steam generator tube rupture (SGTR) and other accident analysis releases to AmerenUE for further evaluation. Subsequently, AmerenUE contracted Westinghouse to provide radiological consequences analysis. The radiological consequences analysis is not documented in the RSG Engineering Report, WCAP-16140. The results are being documented separately. AmerenUE must incorporate the results into their integrated licensing submittal.	Radiological consequences from the RSG project have been transmitted to AUE in W letter SCP-04-74. The results are addressed in OL #1248.	Closed
Trip Time Delay Elimination	Westinghouse provided the necessary licensing documentation to accomplish the modification. AmerenUE must incorporate the results into their integrated licensing submittal.	TTD elimination is evaluated under AmerenUE modification 04-1004.	Closed

APPENDIX A

WCAP-16265-NP
CALLAWAY REPLACEMENT STEAM GENERATOR PROGRAM
NSSS LICENSING REPORT
(NON-PROPRIETARY VERSION)

Proprietary Information Notice

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10CFR2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) contained within parentheses located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the affidavit accompanying this transmittal pursuant to 10CFR2.390(b)(1).

Copyright Notice

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

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

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-04-1868

August 12, 2004

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-16265-P, "Callaway Replacement Steam Generator Program NSSS Licensing Report" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-04-1868 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by AmerenUE.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-04-1868, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: W. Macon, NRC
E. Peyton, NRC
S. Bloom, NRR/OWFN/DRPW/PD1V2 (Rockville, MD)

bcc: J. A. Gresham (ECE 4-7A) 1L
R. Bastien, 1L (Nivelles, Belgium)
C. Brinkman, 1L (Westinghouse Electric Co., 12300 Twinbrook Parkway, Suite 330, Rockville, MD 20852)
RCPL Administrative Aide (ECE 4-7A) 1L, 1A (letter and affidavit only)

CAW-04-1868

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 12th day
of August, 2004

Sharon L. Fiori
Notary Public

Notarial Seal
Sharon L. Fiori, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires January 29, 2007
Member, Pennsylvania Association Of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-16265-P, "Callaway Replacement Steam Generator Program NSSS Licensing Report" (Proprietary), dated August, 2004, being transmitted by AmerenUE Company letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by AmerenUE for the Callaway Nuclear Plant is expected to be applicable for other licensee submittals in response to certain NRC requirements for steam generator replacement.

This information is part of that which will enable Westinghouse to:

(a) Provide documentation of the methods for determining acceptable plant operation at the Replacement Steam Generator conditions.

(b) Provide the specific analysis or evaluation results related to the parameters that are considered for the Replacement Steam Generator project.

(c) Assist the customer to obtain NRC approval.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting NRC requirements for licensing documentation.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculation, evaluation and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended for developing analytical methods and performing tests.

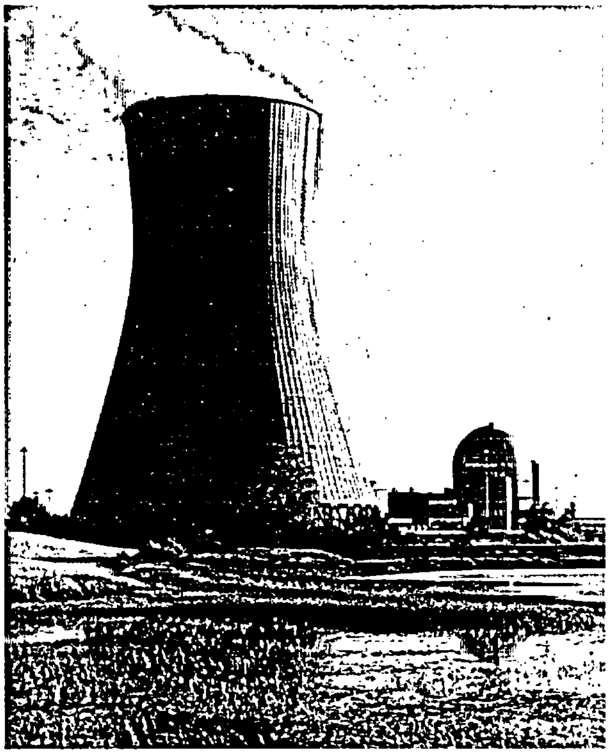
Further the deponent sayeth not.

Westinghouse Non-Proprietary Class 3

WCAP-16265-NP

August 2004

Callaway Replacement Steam Generator Program NSSS Licensing Report



Westinghouse

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LIST OF ACRONYMS AND ABBREVIATIONS

ACC	accumulator
A/E	architect/engineer
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AIA	analysis input assumptions
AMSAC	ATWS mitigation system actuation circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
AO	axial offset
AOR	analysis of record
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
B&PV	Boiler and Pressure Vessel Code
BHP	brake horsepower
BIH	boron injection header
BOC	beginning of cycle
BOL	beginning of life
BOP	balance of plant
BRS	boron recycle system
BTRS	boron thermal regeneration system
C&FS	condensate and feedwater system
CCW	component cooling water
CFR	Code of Federal Regulations
CH	charging
CHF	critical heat flux
CIPs	crud-induced power shift
CLH	capped latch housing
COLR	Core Operating Limits Report
COMS	cold overpressure mitigation system
CPI	control and protection interaction
CRDM	control rod drive mechanism
CSA	channel statistical allowance
CST	condensate storage tank
CVCS	chemical and volume control system
DECLG	double-ended cold leg guillotine
DEG	double-ended guillotine
DEHL	double-ended hot leg
DEPS	double-ended pump suction
DER	double-ended rupture
DNB	departure from nucleate boiling

LIST OF ACRONYMS AND ABBREVIATIONS (cont.)

DNBR	departure from nucleate boiling ratio
DPC	Doppler power coefficient
EAM	environmental allowance monitor
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFPD	effective full-power day
EFW	emergency feedwater
EM	evaluation model
EOC	end of cycle
EOL	end of life
EOP	emergency operating procedures
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety features actuation system
FCV	feedwater control valve
FF	fouling factor
FIV	flow-induced vibration
FL	full length
FLB	feedwater line break
FON	fraction of nominal
FRV	flow regulator valve
FSAR	Final Safety Analysis Report
FW	feedwater
FWI	feedwater isolation
FWIV	feedwater isolation valve
GDC	General Design Criteria
GWPS	gaseous waste processing system
HA	hot assembly
HDR	Heissdampfreaktor
HFP	hot full power
HHSI	high-head safety injection
HI	heat injection
HR	hot rod
HX	heat exchanger
HZP	hot zero power
ID	inner diameter
IFBA	integral fuel burnable absorber
IFM	intermediate flow mixer
IHSI	intermediate-head safety injection

LIST OF ACRONYMS AND ABBREVIATIONS (cont.)

ITDP	Improved Thermal Design Procedure
J-T	J integral-tearing modulus
LBB	leak before break
LBLOCA	large-break LOCA
LCP	lower core plate
LHSI	low-head safety injection
LOCA	loss-of-coolant accident
LOF	loss of flow
LOL	loss of load
LONF	loss of normal feedwater
LOOP	loss of offsite power
LPP	low pressurizer pressure
LPS	last pump startup
LR	locked rotor
LSGWL	low-low steam generator water level
LSP	low steam pressure
LT	long term
LTOPS	low-temperature overpressure system
LWPS	liquid waste processing system
M	manual
M&E	mass and energy
MFIV	main feedwater isolation valve
MFW	main feedwater
MI	mass injection
MMF	minimum measured flow
MS	main steam
MSIV	main steam isolation valve
MSLB	main steam line break
MSS	main steam system
MSSV	main steam safety valve
MST	main steam tunnel
MTC	moderator temperature coefficient
NAI	Numerical Applications, Inc.
NCP	normal charging pump
NEMA	National Electrical Manufacturers' Association
NRC	Nuclear Regulatory Commission
NRS	narrow-range span
NSSS	nuclear steam supply system
NTS	nominal trip setpoint
NUPPSCO	Nuclear Power Plant Standards Committee

LIST OF ACRONYMS AND ABBREVIATIONS (cont.)

OBE	operating basis earthquake
OD	outer diameter
OTΔP	overtemperature delta-T
OTΔT	overtemperature delta-T
PBSR	pressure boundary summary report
PCT	peak cladding temperature
PORV	power-operated relief valve
PRT	pressurizer relief tank
PSV	pressurizer safety valve
PWR	pressurized water reactor
PZR	pressurizer
QMS	quality management system
RAOC	relaxed axial offset control
RCCA	rod cluster control assembly
RCDT	reactor coolant drain tank
RCL	reactor coolant loop
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RHRS	residual heat removal system
RIP	rod internal pressure
RPS	reactor protection system
RPV	reactor pressure vessel
RSAC	reload safety analysis checklist
RSE	reload safety evaluation
RSG	replacement steam generator
RTD	resistance temperature detector
RTDP	Revised Thermal Design Procedure
RTP	rated thermal power
RTS	reactor trip system
RWST	refueling water storage tank
SAL	safety analysis limit
SBLOCA	small-break LOCA
SCP	Callaway
SER	Safety Evaluation Report
SG	steam generator
SGBS	steam generator blowdown system
SGTP	steam generator tube plugging
SGTR	steam generator tube rupture
SI	safety injection

LIST OF ACRONYMS AND ABBREVIATIONS (cont.)

SIS	safety injection system
SLB	steam line break
SLBAP	steam line break event at full power
SRP	Standard Review Plan
SRSS	square root of the sum of the squares
SSDC	systems standard design criteria
SSE	safe shutdown earthquake
SSPS	solid-state protection system
ST	short term
STDP	standard thermal design procedure
SV	safety valve
TA	total allowance
TDF	thermal design flow
TPR	thimble plug removal
TT	turbine trip
TTD	trip time delay
UCP	upper core plate
VCT	volume control tank
WABA	wet annular burnable absorbers
WIN	Westinghouse integral nozzle

EXECUTIVE SUMMARY

The Callaway plant currently has Westinghouse Model F steam generators installed. Framatome designed Model 73/19T replacement steam generators (RSGs) will be installed prior to Cycle 15 operation (in fall of 2005). In support of this change to the Callaway plant, Westinghouse has performed analytical work to address the nuclear steam supply system (NSSS) areas that are affected. This work was completed under what is termed the Callaway RSG NSSS Engineering and Licensing Program. The results and conclusions of those analyses are included in this NSSS Licensing Report.

NSSS LICENSING REPORT

The NSSS Licensing Report documents the results of analyses and evaluations performed by Westinghouse in support of the Callaway RSG Program. In addition to the RSG change, this program also considered the incorporation of a vessel average temperature (Tavg) range into the Callaway design basis, as well as an accident analysis re-baseline effort to update the analyses. The analyses and evaluations were performed in accordance with the bases, criteria, and requirements currently applicable to the Callaway nuclear plant. This Licensing Report and other licensing documentation will support the AmerenUE submittal of the RSG license amendment request to the Nuclear Regulatory Commission (NRC).

Nuclear Fuel and NSSS Accident Analysis

Analyses and evaluations were performed for the nuclear fuel and the NSSS accidents that are impacted by the RSG to demonstrate that applicable licensing criteria and requirements are satisfied at the revised conditions.

NSSS Systems and Components

Those portions of the design of the NSSS systems and NSSS components that are impacted by the RSG will be analyzed or evaluated to demonstrate that they continue to comply with applicable codes, standards, and requirements.

APPROACH

The NSSS portion of the overall Callaway RSG Program is consistent with established methodology that has been used successfully on many other RSG programs. The analyses and evaluations were performed in conformance with Westinghouse and industry codes, standards, and regulatory requirements applicable to Callaway. The analyses and evaluations of NSSS systems, components, and accident analyses were completed based on the NSSS design parameters, the NSSS design transients, and the detailed analysis input assumptions (AIA) established at the beginning of the program.

CONCLUSION

The results of the Westinghouse analyses and evaluations demonstrate that applicable licensing criteria and requirements are satisfied for RSG conditions for those systems, components, and accidents analyses within the Westinghouse scope of supply for this project.

1 INTRODUCTION

1.1 BACKGROUND

The Callaway plant currently has Westinghouse Model F steam generators installed. Framatome designed Model 73/19T replacement steam generators (RSGs) will be installed prior to Cycle 15 operation (in fall of 2005). In support of this change to the Callaway plant, Westinghouse has performed analytical work to address the nuclear steam supply system (NSSS) areas that are affected. This work was completed under what is termed the Callaway RSG NSSS Engineering and Licensing Program. The results and conclusions of those analyses are included in this NSSS Licensing Report.

1.2 PURPOSE

The purpose of this NSSS Licensing Report is to document the results of analyses and evaluations performed by Westinghouse in support of the Callaway RSG Program. The results demonstrate that those aspects of the Callaway plant documented in this report are in compliance with the applicable licensing criteria and regulatory requirements and the plant can continue to safely operate with the RSGs installed.

1.3 MAJOR INPUT ASSUMPTIONS

The Westinghouse analyses and evaluations performed to support the RSG are based on the following major input assumptions:

- The current NSSS power level of 3,579 MWt (3,565 MWt core power)
- A range of nominal feedwater temperatures from 390° to 446°F
- The current fuel type of 17x17 V5 remains unchanged
- The current thermal design flow (TDF) of 93,600 gpm/loop is maintained
- Full-power normal operating vessel average temperature (Tavg) range from 570.7° to 588.4°F is considered

  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 RSG conditions, provided that the full-load Tavg is no lower than 573°F.
- Steam generator tube plugging (SGTP) range of 0 to 5 percent

Additional specific assumptions and acceptance criteria are presented in the appropriate sections of the report.

The Tavg range of 570.7° to 588.4°F is a change to the current Callaway analysis basis and required additional analytical work to demonstrate the acceptability of the plant. The range was incorporated to allow operating flexibility as well as the capability for an end-of-cycle Tavg coastdown.

The analyses and evaluations were performed based on the Westinghouse methods, the current analyses of record and the detailed analysis input assumption (AIA) list. The AIA list was developed to document and control the inputs to the Westinghouse analyses and evaluations. The list was reviewed and approved by AmerenUE.

1.4 LICENSING REPORT SCOPE

The analyses and evaluations described herein were performed in accordance with the bases, criteria, and requirements currently applicable to the Callaway nuclear plant. This section briefly describes the work scope associated with the Callaway RSG effort. This Licensing Report and other licensing documentation will support the AmerenUE submittal of the RSG license amendment request to the Nuclear Regulatory Commission (NRC).

Nuclear Fuel and NSSS Accident Analysis

Analyses and evaluations were performed for the nuclear fuel and the NSSS accidents that are impacted by the RSG to demonstrate that applicable licensing criteria and requirements are satisfied at the revised conditions.

NSSS Systems and Components

Those portions of the design of the NSSS systems and NSSS components that are impacted by the RSG were analyzed or evaluated to demonstrate that they continue to comply with applicable codes, standards, and requirements.

1.5 APPROACH AND METHODOLOGY

The NSSS portion of the overall Callaway RSG Program is consistent with established methodology that has been used successfully on many other RSG programs. The analyses and evaluations were performed in conformance with Westinghouse and industry codes, standards, and regulatory requirements applicable to Callaway. The analyses and evaluations of NSSS systems, components, and accident analyses were completed based on NSSS design parameters (Section 2.0) and the NSSS design transients (Section 3.0), along with the detailed AIA list.

The following approach was used to assess the impact of the RSG on NSSS components for operation at the revised conditions:

- Revise the NSSS design transients (that is, temperature/pressure profiles) to be applicable to RSG conditions.
- Use the revised NSSS design transient profiles to analyze the NSSS components to determine the fatigue usage factors for RSG conditions.
- The fatigue usage factors were then compared to the code acceptance limits to show that the NSSS components comply with American Society of Mechanical Engineers (ASME) Code acceptance criteria and can operate acceptably at RSG conditions.

The NSSS design parameters provided in Section 2.0 were selected to establish conservative values for some fundamental parameters (such as, reactor coolant system (RCS) TDF) and conservative bounding ranges for other fundamental parameters (such as, RCS Tavg and SGTP level).

The NSSS analyses and evaluations were performed in accordance with Westinghouse quality assurance requirements defined in the Westinghouse Quality Management System (QMS) procedures, which comply with the Code of Federal Regulations (CFR) 10 CFR 50 Appendix B criteria.

1.5.1 Analysis Methodologies and Computer Codes

The evaluations or analyses were performed using currently approved analytical techniques to demonstrate compliance with the licensing criteria and standards that apply to Callaway. The NRC-approved techniques are the same as those used for current Callaway analyses and are described in the Callaway Final Safety Analysis Report (FSAR).

Exceptions to the above are as follows. These analyses areas employ the first-time application of the following NRC approved methods for Callaway:

- LOCA Mass and Energy (M&E) Release
  - "Westinghouse LOCA Mass and Energy Release Model for Containment Design – March 1979 Version," WCAP-10325-P-A, May 1983 (Refer to Section 6.5)
- Non-LOCA, Steam Generator Tube Rupture and Steam Line Break M&E Release
  - "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A, April 1999 (Refer to Sections 6.3, 6.4, and 6.6.1)

The following non-LOCA areas are also first-time applications of methodologies for the Callaway plant.

<u>Excessive Increase In Secondary Steam Flow Event - FSAR Section 15.1.3</u>

This analysis was addressed by Westinghouse using a statepoint analysis instead of an explicit analysis via the RETRAN code. This transient does not typically result in the actuation of any reactor protection system (RPS) function (that is, no reactor trip). The effect of this transient on the minimum departure from nucleate boiling ratio (DNBR) was evaluated by applying conservatively large deviations on the initial conditions for power, average coolant temperature, and pressurizer pressure at the normal full-power operating conditions in order to generate a limiting set of statepoints. These deviations bound the variations that could occur as a result of an excessive load increase incident and are only applied in the direction that had the most adverse impact on DNBR (increased power and coolant temperature, and decreased pressure). The reactor condition statepoints (power, temperature, and pressure) are then compared to the conditions corresponding to operation at the departure from nucleate boiling (DNB) safety analysis limit.

The results of the statepoint analysis performed to support the RSG Program show that the acceptance criteria (for example, minimum DNBR, etc.) are met. This type of statepoint analysis has been previously used by Westinghouse on other RSG and power uprate programs. These previous analyses have been accepted by the NRC and the NRC will again review the results of this statepoint analysis as part of the RSG license amendment.

Loss Of Normal Feedwater (LONF) Event - FSAR Section 15.2.7

This analysis was addressed by Westinghouse using the RETRAN code. However, in conjunction with the FSAR analysis, a separate analysis is performed to address the reliability of the auxiliary feedwater system (AFWS). The analysis is performed in a manner similar to that described above for the FSAR Chapter 15 analysis, but assuming that only a single motor-driven auxiliary feedwater (AFW) pump is available to feed two of the four steam generators. The cases considered in this additional analysis assume better-estimate conditions for several key input parameters. Specifically, initial conditions (NSSS power, RCS pressure and temperature, pressurizer level), and reactor trip and equipment setpoints are assumed to be at their nominal values. Most importantly, a better-estimate decay heat model, consistent with American Nuclear Society (ANS) 1971 full decay heat with no uncertainties, is used. This is the first implementation of the dual-analysis approach to separately address Chapter 15 and AFWS reliability concerns for the loss of normal feedwater event for Callaway. Previously, a single bounding analysis had been performed combining the conservative Chapter 15-type assumptions and the reduced AFW flow consistent with a single motor-driven AFW pump. This resulted in an analysis that was overly conservative. Utilizing the dual-analysis approach, with both analyses assuming the failure of the turbine-driven AFW pump as the limiting single failure, allows the plant to address both concerns separately while continuing to show that the conservative acceptance criterion used by Westinghouse for this event (preventing pressurizer filling) is met for both scenarios. By demonstrating that acceptable results are achieved in this separate analysis crediting a single motor-driven AFW pump, the Chapter 15 analysis can be performed assuming the operation of both available motor-driven AFW pumps. The dual-analysis approach has been previously used by Westinghouse in at least one other loss of normal feedwater analysis of a Westinghouse-designed plant.

The dual-analysis approach has been previously used by Westinghouse in one other LONF analysis of a Westinghouse-designed plant. That previous analysis has been accepted by the NRC and the NRC will again review the results of this dual-analysis approach as part of the RSG license amendment.

- Core Thermal-Hydraulic Design
  - "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A, October 1999 (Refer to Section 7.1)

The WCAP references given above have the "-A" designation included in the number. This indicates that these methodologies are approved by the NRC and that an NRC Safety Evaluation Report (SER) was issued. The reports typically contain the NRC SER or refer to the SER.

The following is a listing of the NRC SER letters for the WCAP references given above:

Report	NRC SER Reference
WCAP-10325-P-A	Safety Evaluation Report from C. Rossi (NRC) to W. Johnson (Westinghouse), February 17, 1987
WCAP-14882-P-A	Safety Evaluation Report from F. Akstulewicz (NRC) to H. Sepp (Westinghouse), February 11, 1999
WCAP-14565-P-A	Safety Evaluation Report from T. Essig (NRC) to H. Sepp (Westinghouse), January 19, 1999

Table 1-1 contains a list of the computer codes used in each analytical area, along with the applicable section of this Licensing Report. Table 1-2 provides brief descriptions of the computer codes used.

1.6 WESTINGHOUSE PROPRIETARY INFORMATION DESIGNATIONS

There is information contained in this report that Westinghouse considers to be Westinghouse Proprietary. The specific information is contained within the brackets with designated superscripted letters (a through f), for example:

[Westinghouse Proprietary Information][a,c]

The reason for marking Westinghouse Proprietary information in this report is so that, if any portion of this report is used to prepare documents to be submitted to the NRC (for example, a licensing report or license amendment request), the authors will be aware of exactly which information is proprietary to Westinghouse and can protect the information accordingly. When a licensing report or any other document is submitted to the NRC for review, either the information proprietary to Westinghouse Electric Company LLC must be omitted from the submittal, or a non-proprietary version suitable for public disclosure must also be submitted.

Table 1-1 Callaway RSG Program - Westinghouse Computer Codes Used		
Report Section	**Analysis**	**Computer Code[1, 2]**
4.3	NSSS Control Systems	LOFTRAN
5.2.1	Heat Generation Rates	DORT/BUGLE-96
5.2.2	Reactor Vessel Internals	WECAN/Plus ANSYS
5.5.1	Reactor Coolant Loop Piping	WESTDYN WECAN
6.2	LBLOCA	SATAN-VI BASH COCO LOCBART
	SBLOCA	NOTRUMP SBLOCTA
6.3	Non-LOCA Transients	RETRAN ANC VIPRE LOFTRAN
6.4	SGTR	RETRAN
6.5	LOCA LT/ST M&E	SATAN VI WREFLOOD FROTH EPITOME
6.6	MSLB M&E Releases Inside and Outside Containment	RETRAN LOFTRAN
6.7	Steam Tunnel (Area 5) Analysis	GOTHIC
6.8	LOCA Hydraulic Forces	MULTIFLEX 3.0 LATFORC FORCE2 THRUST
7.1	Core Thermal-Hydraulic Design	VIPRE
7.2	Fuel Core Design	ANC PHOENIX-P
7.3	Fuel Rod Design and Performance	PAD 3.4; PAD 4.0

Notes for Table 1-1:

1. See Table 1-2 for a brief description of each code.
2. All codes listed are maintained under Westinghouse configuration control.

Table 1-2 Computer Code Description
ANC
ANC is an advanced nodal code capable of two-dimensional and three-dimensional neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, and so forth. In addition, three-dimensional ANC validates one-dimensional and two-dimensional results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.
Reference:
WCAP-10965-P-A, "ANC: A Westinghouse Advanced Nodal Computer Code," September 1986.
ANSYS 6.1
The ANSYS computer code is a general-purpose finite element code with capabilities including structural and thermal-hydraulic static and dynamic analyses.
Reference:
Letter LTR-SST-02-33, "Release of ANSYS 6.1 on NT 4.0, HPUX 11 & Solaris 2.8," September 26, 2002.
BASH
The BASH code calculates the refill and reflood portions of the large-break-loss-of-coolant-accident (LOCA) transient. During refill, the storage and transport of water from the emergency core cooling system (ECCS) injection points to the reactor vessel lower plenum are modeled. During reflood, BASH performs the core thermal-hydraulic and heat transfer calculations, as well as the RCS transient response calculations. BASH calculates the reflood rate and inlet enthalpy which are input to LOCBART, as well as the mass and energy discharge rates from the RCS to containment during reflood for the COCO code.
Reference:
WCAP-10266-P-A, Revision 2 (Proprietary), "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," March 1987.
COCO
Calculation of containment pressure and temperature is accomplished by use of the digital computer code COCO. COCO is a mathematical model of a generalized containment. The proper selection of various options in the code allows the creation of a specific model for a particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and found acceptable to calculate containment pressure transients for many dry containment plants. Transient phenomena within the RCS affect containment conditions by means of convective M&E transport through the pipe break.
For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water (pool) phase and a steam-air phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each system, together with appropriate boundary conditions. As thermodynamic equations of state and conditions may vary during the transient, the equations have been derived for all possible cases of superheated or saturated steam and subcooled or saturated water. Switching between states is handled automatically by the code.
The COCO code is also run interactively with the LBLOCA BASH code and models the containment behavior for dry containment plants during the large-break LOCA transient. It calculates the pressure and temperature transients inside the containment during the depressurization and post-blowdown phase following a LOCA.

Table 1-2 (cont.) Computer Code Description

References:

1. WCAP-8327 (Proprietary) and WCAP-8326 (Non-Proprietary), "Containment Pressure Analysis Code (COCO)," F. M. Bordelon and E. T. Murphy, June 1974.
2. WCAP-8471-P-A (Proprietary), "The Westinghouse ECCS Evaluation Model: Supplementary Information," April 1975.

DORT/BUGLE-96

The DORT discrete ordinates transport module of the DOORS 3.1 code package, in conjunction with the BUGLE-96 cross-section library, is used to determine the neutron flux and gamma-ray heating rate environment. This code and the associated cross-section library have been used by Westinghouse to calculate vessel fluences and reactor internals heating rates for other projects that have been submitted to, and approved by, the NRC. Furthermore, these calculation tools are specified in Regulatory Guide 1.190 for this type of work.

References:

1. RSICC Computer Code Collection CCC-650, "DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System," August 1996.
2. RSICC Data Library Collection DLC-185, "BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross-Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications," March 1996.
3. Regulatory Guide RG-1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," U. S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, March 2001.

EPITOME (See also SATAN-VI, WREFLOOD, and FROTH)

The EPITOME code continues the FROTH post-reflood portion of the transient from the time at which the secondary side equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times. EPITOME is essentially an automated hand calculation.

Reference:

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

FORCE2 (See also MULTIFLEX)

The FORCE2 program calculates the hydraulic forces that the fluid exerts on the vessel internals in the vertical direction by utilizing a detailed geometric description of the vessel components and the transient pressures, mass velocities, and densities computed by the MULTIFLEX code. The analytical basis for the derivation of the mathematical equations employed in the FORCE2 code is the conservation of linear momentum (one-dimensional). Note that the computed vertical forces in the LOCA forces analyses do not include body forces on the vessel internals, such as dead-weight or buoyancy. The dead-weight and other factors are part of the dynamic system model to which the LOCA forces are provided as an external load. When the vertical forces on the reactor pressure vessel internals are calculated, pressure differential forces, flow stagnation on, unrecoverable orifice losses across, and friction losses on, the individual components are considered. These force types are then summed together, depending upon the significance of each, to yield the total vertical force acting on a given component.

References:

1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977.
2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977.

Table 1-2 (cont.) **Computer Code Description**

FROTH (See also SATAN-VI, WREFLOOD, and EPITOME)

The FROTH code is used for computing the post-reflood transient. The FROTH code is used for the steam generator heat addition calculation from the broken and intact loop steam generators.

The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. During the FROTH calculation, ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH computer code calculates the heat removal from the secondary mass until the secondary side equilibrates to the saturation temperature at the containment design pressure.

References:

1. WCAP-9221-NP-A, Revision 1, "Westinghouse ECCS Evaluation Model – 1981 Version."
2. WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Non-Proprietary), "Westinghouse LOCA Mass and Energy Release Model for Containment Design – March 1979 Version," May 1983.

GOTHIC

The GOTHIC code is a state-of-the-art program for modeling multiphase flow. GOTHIC actually consists of three separate programs. The preprocessor allows the user to rapidly create and modify an input model. The solver performs the numerical solution for the problem. The postprocessor, in conjunction with the preprocessor, allows the user to rapidly create graphical and tabular outputs for virtually any parameter in the model.

GOTHIC solves the integral form of the conservation equations for mass, momentum, and energy for multi-component, two-phase flow. The conservation equations are solved for three fields; continuous liquid, liquid drops, and the steam/gas phase. The three fields may be in thermal non-equilibrium within the same computational cell. This would allow the modeling of subcooled drops (e.g., containment spray) falling through an atmosphere of saturated steam. The gas component of the steam/gas field can be comprised of up to eight different non-condensable gases with mass balances performed for each component. Relative velocities are calculated for each field as well as the effects of two-phase slip on pressure drop. Heat transfer between the phases, surfaces, and the fluid are also allowed.

The GOTHIC code is capable of performing calculations in three modes. The code can be used in the lumped parameter nodal network mode, the two-dimensional finite difference mode, and the three-dimensional finite difference mode. Each of these modes may be used within the same model. The capability of multi-dimensional analyses greatly enhances the ability to study non-condensable gases and stratification as well as allowing the calculation of flow field details within any given volume.

The GOTHIC code also contains the options to model a large number of structures and components. These include, but are not limited to, heated and unheated conductors, pumps, fans, a variety of heat exchangers, and ice condensers. These components can be coupled to represent the various systems found in any typical containment.

The GOTHIC code has undergone extensive review and validation against an impressive array of tests. The code has been validated against a number of Battelle-Frankfurt tests performed to study steam blowdowns and hydrogen releases. A selection of Hanford Engineering Development Laboratory tests were modeled to simulate steam-hydrogen jets. The LACE tests were modeled to validate rapid depressurization events with aerosols. A variety of the Heissdampfreaktor (HDR) full-scale containment tests were modeled to study steam and water blowdowns and hydrogen releases in a full-scale multi-compartment containment geometry.

GOTHIC has been used to study hydrogen distributions, containment pressure and temperature transients, perform flow field calculations for particle transport purposes, and surge-line flooding studies for loss of residual heat removal (RHR) cooling events during shutdown operations. The flexible noding and conservation equation solutions in the code allow its application to a wide variety of problems, not necessarily just containment pressure and temperature calculations.

Table 1-2 (cont.) **Computer Code Description**

Reference:

NAI 8907-02, Revision 14, "GOTHIC Containment Analysis Package User Manual," Version 7.1, January 2003.

LATFORC (See also MULTIFLEX)

The LATFORC computer code utilizes MULTIFLEX generated field pressures, together with geometric vessel information (component radial and axial lengths), to determine the horizontal forces on the vessel wall and core barrel. The LATFORC code represents the vessel region with a model that is consistent with the model used in the MULTIFLEX blowdown calculation. The downcomer annulus is subdivided into cylindrical segments, formed by dividing this region into circumferential and axial zones. The results of the MULTIFLEX/LATFORC analysis of the horizontal forces are typically stored on magnetic tape and are calculated for the initial 500 msec of the blowdown transient. These forcing functions serve as required input in determining the resultant mechanical loads on primary equipment and loop supports, vessel internals, and fuel grids.

References:

1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977.
2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977.

LOCBART

The LOCBART code calculates fuel rod temperature profiles, cladding burst, and cladding oxidation during the large-break LOCA sequence. The mass flow, pressure, and enthalpy information during blowdown is obtained from SATAN-VI, and the flooding rate and inlet enthalpy during reflood are obtained from BASH.

Reference:

WCAP-10266-P-A, Revision 2 (Proprietary), "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," March 1987.

LOFTRAN

The LOFTRAN computer program is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. LOFTRAN simulates up to four-loop systems by modeling the reactor vessel, hot and cold leg piping, steam generators (tube and shell sides), and pressurizer. The pressurizer heaters, spray, relief, and safety valves are also considered in the program. Point-model neutron kinetics and reactivity effects of the moderator, fuel, boron and rods are included. The secondary sides of the steam generators utilize a homogeneous, saturated mixture for the thermal transients, and a water level correlation for indication and control. The reactor protection system simulation includes reactor trips on neutron flux, overpower and overtemperature ΔT, high and low pressure, low flow, and high pressurizer water level. Control systems, including rod control, steam dump, feedwater control, and pressurizer pressure controls are also simulated. The safety injection system, including the accumulators, is also modeled.

LOFTRAN is a versatile program suited to accident evaluation and control studies as well as parameter sizing. It is also used in performing loss of normal feedwater anticipated transient without scram (ATWS) and loss-of-load ATWS evaluations and control systems analysis.

Reference:

WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), "LOFTRAN Code Description," April 1984.

MULTIFLEX (See also LATFORC, FORCE2, and THRUST)

The analysis for LOCA hydraulic forces used the NRC-accepted MULTIFLEX computer code, which is the current Westinghouse analytical tool used for analyzing LOCA hydraulic forces. The code was used to generate the

Table 1-2 (cont.) Computer Code Description
transient hydraulic forcing functions on the vessel and internals. This code was previously used for LOCA hydraulic forces analyses. MULTIFLEX 3.0 is an engineering design tool that is used to analyze the coupled fluid-structural interactions in a PWR system during the transient following a postulated pipe rupture in the main RCS. The thermal-hydraulic portion of the MULTIFLEX code is based on the one-dimensional homogeneous model expressed in a set of mass, momentum, and energy conservation equations. These equations are quasi-linear, first order, partial differential equations solved by the method of characteristics. The employed numerical method utilizes an explicit time scheme along the respective characteristics. MULTIFLEX considers the interaction of the fluid and structure simultaneously, whereby the mechanical equations of vibration are solved through the use of the modal analysis technique. MULTIFLEX 3.0 generates the input for the post-processing codes LATFORC, FORCE2, and THRUST. References: 1. WCAP-8708-PA-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977. 2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977. 3. WCAP-9735, Revision 2 (Proprietary) and WCAP-9736, Revision 1 (Non-Proprietary), "MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model," February 1998. 4. WCAP-15029-P-A, Revision 0 (Proprietary) and WCAP-15030-NP-A, Revision 0 (Non-Proprietary), "Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions," January 1999.
NOTRUMP/SBLOCTA The approved codes for Appendix K small-break LOCA analyses are NOTRUMP and SBLOCTA. The NOTRUMP computer code is a one-dimensional general network code consisting of a number of advanced features. Among these features is the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat-transfer correlations. Additional features of the code are condensation heat-transfer model applied in the steam generator region, loop seal model, core reflux model, flow regime mapping, etc. The SBLOCTA computer code is used to model the fuel rod response to the small-break LOCA transient. It models three rods in the hot assembly (hot, average, and adjacent), modeling simultaneous radial and axial conduction. Other modeling features include various skewed axial power shapes, assembly blockage model due to cladding swell, and rupture and zirc/water reaction. NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time-dependent values of various core region parameters, such as system pressure, temperature, fluid levels, and flow rates. These are provided as boundary conditions to SBLOCTA. SBLOCTA then uses these conditions and various hot channel inputs to calculate the rod heatup and ultimately, the peak cladding temperature (PCT) for a given transient. Additional variables calculated by SBLOCTA are cladding pressure, strain, and oxidation. References: 1. WCAP-10079-P-A (Proprietary), "NOTRUMP, A Nodal Transient Small Break and General Network Code," August 1985. 2. WCAP-10054-P-A (Proprietary), "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," Lee et. al., August 1985.

Table 1-2 (cont.) Computer Code Description
3. WCAP-10054-P-A, Addendum 2, Revision 1 (Proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," Thompson et. al., July 1997. 4. WCAP-8301 (Proprietary), "LOCTA-IV Program: Loss of Coolant Transient Analysis," F. M Bordelon et al., June 1974.
PAD 3.4/4.0 The NRC-approved PAD code, with NRC-approved models for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power. Fuel rod design and safety analyses are based on updated values (up to 100-percent helium gas release) for the integral fuel burnable absorber (IFBA) helium gas release model. PAD is a best-estimate fuel rod performance model. In most cases, the design criterion evaluations are based on a best-estimate plus uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties are measured for some critical inputs (e.g., fuel pellet diameter), and when available, can be used in lieu of the fabrication uncertainties. References: 1. WCAP-12610-P-A, "VANTAGE + Fuel Assembly Reference Core Report," April 1995. 2. WCAP-10851-P-A, "Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluations," August 1988. 3. WCAP-15063-P-A, Revision 1, with Errata (Proprietary), "Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)," J. P. Foster and S. Sidener, July 2000.
PHOENIX-P PHOENIX-P is a 2-dimensional, multi-group transport theory computer code. The nuclear cross-section library used by PHOENIX-P contains cross-section data based on a 70-energy-group structure derived from ENDF/B-VI files. PHOENIX-P performs a two-dimensional 70-group nodal flux calculation which couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique. This 70-group solution is normalized by a coarse energy group flux solution derived from a discrete ordinates calculation. PHOENIX-P is capable of modeling all cell types needed for PWR core design applications. Reference: WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," T. Q. Nguyen et al., June 1988.
RETRAN RETRAN is used for studies of transient response of a PWR system to specified perturbations in process parameters. This code simulates a multiloop system by a lumped parameter model containing the reactor vessel, hot and cold leg piping, reactor coolant pumps, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves may also be modeled. RETRAN includes a point neutron-kinetics model and reactivity effects of the moderator, fuel boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RPS simulated in the code includes reactor trips on high neutron flux, OTΔT and OPΔT, low RCS flow, high and low pressurizer pressure, high pressurizer water level, and low-low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS),

Table 1-2 (cont.) Computer Code Description
including the accumulators, may be modeled. RETRAN approximates the transient value of DNBR based on input from the core thermal safety limits. Reference: WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D. S. Huegel et al., April 1999.
SATAN-VI The SATAN-VI code calculates the thermal-hydraulic behavior of the reactor core and RCS during the blowdown phase of the large-break LOCA transient. The code provides thermal-hydraulic parameters that define the blowdown boundary conditions in the BASH and LOCBART codes. It also provides M&E discharge rates from the RCS to containment for the COCO code. References: 1. WCAP-8302 (Proprietary), "SATAN VI Program: Comprehensive Space-Time Dependent Analysis of Loss-of-Coolant," June 1974. 2. WCAP-8471-P-A (Proprietary), "The Westinghouse ECCS Evaluation Model: Supplementary Information," April 1975.
THRUST (See also MULTIFLEX) The THRUST program calculates the hydraulic forces that the fluid exerts on the reactor coolant loop. The THRUST code uses the MULTIFLEX LOCA pressure transient as input in the calculation of the loop forces. In the THRUST computer code, the loop piping is represented by a series of control volumes. The pressure forces are calculated by THRUST wherever there are changes in either loop area or direction. The LOCA loop forces are then transmitted to the appropriate structural analysis group where they are then combined with the other design-basis loads (i.e., seismic, thermal and system shaking loads) where they are used to qualify the reactor coolant loops under the design-basis loads. References: 1. WCAP-8708-P-A-V1 (Proprietary) and WCAP-8709-A (Non-Proprietary), "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," September 1977. 2. WCAP-8252, Revision 1, "Documentation of Selected Westinghouse Structural Analysis Computer Codes," May 1977.
VIPRE VIPRE-01 (VIPRE) is a three-dimensional subchannel code that has been developed to account for hydraulic and nuclear effects on the enthalpy rise in the core and hot channels. The VIPRE code is based on a knowledge and understanding of the heat transfer and hydrodynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The use of the VIPRE analysis provides a realistic evaluation of the core performance and is used in the thermal-hydraulic analysis. The VIPRE core model as approved by the NRC (Reference 1) is used with the applicable DNB correlations to determine DNBR distributions along the hot channels of the reactor core under all expected operating conditions. The VIPRE code is described in detail in Reference 2, including discussion on code validation with experimental data. The VIPRE modeling method is described in Reference 1, including empirical models and correlations used. The effect of crud on the flow and enthalpy distribution in the core is not directly accounted for in the VIPRE evaluations. However, conservative treatment by the VIPRE modeling method has been demonstrated to bound this effect in DNBR calculations.

Table 1-2 (cont.) **Computer Code Description**

References:

1. WCAP-14565-P-A and WCAP-15306-NP-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," Y. X. Sung et al, October 1999.
2. NP-2511-CCM-A, "VIPRE-01: A Thermal-Hydraulic Code for Reactor Core, Volume 1-3 (Revision 3, August 1989; Volume 4 (April 1987)," Electric Power Research Institute, C. W. Stewart et al.

WECAN

The WECAN computer code is a general-purpose finite element code with capabilities including structural and thermal-hydraulic static and dynamic analyses. It is a direct descendant of the mainframe-version of the WECAN code that has been used in the nuclear industry since the early 1970s. It has been used by Westinghouse for safety-related work for many years on essentially all Westinghouse-provided NSSS analyses such as core structural design (analyses including static, dynamic, and thermal), primary piping, primary equipment supports, primary equipment components, and spent fuel rack design.

The WECAN computer program can be used to solve a large variety of structural analysis problems. These problems can be one-, two-, or three-dimensional in nature. It is capable of static elastic and inelastic analysis, steady-state hydraulic analysis, standard and reduced modal analysis, harmonic response analysis, and transient dynamic analysis.

The WECAN program is based on the finite element method of analysis. The analyst must model, or idealize the structure in terms of discrete elements and apply loadings and boundary conditions to these elements. The stiffness (or conductivity) matrix for each element is assembled into a system of simultaneous linear equations for the entire structure. This set of equations is then solved by a variation of the Gaussian elimination method known as the wave front technique. This type of solution makes it possible to solve systems with a large number of degrees of freedom using a minimum amount of core storage. The maximum number of allowed degrees of freedom in the wave front depends on the amount of core available, which in turn depends on the type of analysis being performed.

WECAN is organized in such a way that additional structural elements can be added with a minimum of effort. Input formats are similar for all elements and all types of analysis. Input used in the static analysis of a structure can be used for a dynamic analysis with only minor modifications.

References:

1. Letter EDRE-EMT-362, "WECAN 97 Release Letter," December 19, 1997.
2. Letter LTR-SGDA-20-15, "Release of WECAN/Plus Version 99 on the HP-UX 10.20ACE and HP-UX 11.0 System States," January 18, 2002.

WESTDYN

WESTDYN, a computer program used for the structural analysis of piping systems, calculates displacement, internal forces, and stress distributions in three-dimensional piping models while subjecting them to static and dynamic loads.

The static analysis includes pressure, dead-weight, thermal expansion, distributed and point loads, anchor motion, and uniformly applied accelerations.

The dynamic analysis includes seismic or hydrodynamic response spectra and time-history dynamic analysis. The time-history dynamic analysis includes options for non-linear supports, support gaps, and unidirectional single acting restraints.

In addition, WESTDYN utilizes post-processors for the stress analysis of ASME 1, 2, 3, or American National Standards Institute (ANSI) B31.1 piping and also for generating support load summary sheets and equipment and component qualification input data.

Table 1-2 (cont.) Computer Code Description
WESTDYN automatically calculates stress indices for standard ANSI fittings by user selection of the ASME piping evaluation code and edition. Allowable piping stress limits, coefficients of thermal expansion, and moduli of elasticity for a wide range of materials are also automatically calculated with user-supplied design and operating data. Reference: EDRE-SMT-98-121 "Release of WESTDYN Version 7.1," W. R. Morrison, C. K. Ng, November 3, 1998.
WREFLOOD (See also SATAN-IV, FROTH, and EPITOME) The WREFLOOD code is used for computing the reflood transient. It addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and when water supplied by the ECCS refills the reactor vessel and provides cooling to the core. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped safety injection and accumulators, reactor coolant pump performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters such as core flooding rate, core downcomer water levels, fluid thermodynamic conditions (i.e., pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. References: 1. WCAP-9221-NP-A, Revision 1, "Westinghouse ECCS Evaluation Model – 1981 Version." 2. WCAP-8264-P-A, Revision 1 (Proprietary), WCAP-8312-A (Non-Proprietary), "Westinghouse Mass and Energy Release Data for Containment Design," August 1975.

2 NUCLEAR STEAM SUPPLY SYSTEM DESIGN PARAMETERS

2.1 INTRODUCTION

The nuclear steam supply system (NSSS) design parameters are the fundamental parameters used as input in all of the NSSS analyses. They provide the primary- and secondary-side system conditions (temperatures, pressures, and flow) that are used as the basis for all of the NSSS analyses and evaluations. It was necessary to revise the current Callaway parameters due to the Replacement Steam Generator (RSG) Program. The new parameters are identified in Table 2-1. These parameters have been incorporated, as required, into the applicable NSSS systems and components evaluations, as well as safety analyses, performed in support of the RSG Program.

2.2 INPUT PARAMETERS AND ASSUMPTIONS

The NSSS design parameters provide the reactor coolant system (RCS) and secondary-side system conditions (temperatures, pressures, and flow) that are used as the basis for the design transients, systems, components, accidents, and fuel analyses and evaluations.

The major input parameters and assumptions used in the calculation of the four cases of NSSS design parameters established for the RSG Program are summarized below:

- The parameters are applicable to Framatome RSG Model 73/19T steam generators (SGs).
- The current NSSS power level of 3,579 MWt (3,565 MWt core power + 14 MWt RCS net heat input) was maintained for the RSG
- A range of nominal feedwater temperatures (Tfeed) from 390° to 446°F was selected for the analyses.
- The parameters are applicable to 17x17 V5 fuel.
- The design core bypass flow was assumed to be 8.6 percent, which accounts for intermediate flow mixers (IFMs) and thimble plug removal (TPR).
- The thermal design flow of 93,600 gpm/loop was maintained.
- A range of full-power normal operating Tavg from 570.7° to 588.4°F was selected for the analyses. This is a change from the current design, which considered a range from 583.4° to 588.4°F.
- The steam generator tube plugging (SGTP) levels assumed were 0 and 5 percent at both Tavgs.
- The reactor coolant pressure of 2,250 psia assumed is the current operating value.
- A maximum steam generator moisture carryover of 0.10 percent was utilized.

2.3 DISCUSSION OF PARAMETER CASES

Table 2-1 provides the NSSS design parameter cases generated and used as the basis for the RSG Program.

Cases 1 and 2 represent parameters based on the maximum Tavg of 588.4°F. Case 1 provides conservatively high secondary-side performance conditions since it is based on 0-percent SGTP and maximum design Tavg. Note that all primary-side temperatures are identical for these 2 cases.

Cases 3 and 4 represent parameters based on the minimum Tavg of 570.7°F. Case 4 yields the minimum secondary-side steam generator pressure and temperature. Note that all primary-side temperatures are identical for these 2 cases.

The RSG design resulted in changes to the steam pressure compared to the current analyses of record. The steam pressure increased by 52 psi for parameters at the same conditions.

These changes were evaluated by each of the analytical areas discussed in this report.

2.4 ACCEPTANCE CRITERIA FOR DETERMINATION OF PARAMETERS

The primary acceptance criteria for the determination of the NSSS design parameters were that they are not overly conservative that they penalize the RSG Program analysis results, and that they provide AmerenUE with adequate flexibility and margin in the operation of the plant.

2.5 CONCLUSIONS

The resulting NSSS design parameters shown in Table 2-1 were issued and used by Westinghouse in all the analytical efforts. Westinghouse performed the analyses and evaluations based on the parameter sets that were most limiting, so that the analyses would support operation over the range of conditions specified.

Table 2-1 NSSS Design Parameters for Callaway RSG Program

BASIC COMPONENTS			
Reactor Vessel, ID, in.	173	Isolation Valves	No
Core		Number of Loops	4
Number of Assemblies	193	Steam Generator	
Rod Array	17x17 V5	Model	(1)
Rod OD, in.	0.360	Shell Design Pressure, psia	1200
Number of Grids	6Z/2I/3IFM	Reactor Coolant Pump	
Active Fuel Length, in.	144	Model/Weir	93A1/Yes
Number of Control Rods, FL	53	Pump Motor, hp	7000
Internals Type	SCP	Frequency, Hz	60

	Replacement Steam Generator Program(1)			
THERMAL DESIGN PARAMETERS	Case 1	Case 2	Case 3	Case 4
NSSS Power, %	100	100	100	100
MWt	3579	3579	3579	3579
10^6 Btu/hr	12,212	12,212	12,212	12,212
Reactor Power, MWt	3565	3565	3565	3565
10^6 Btu/hr	12,164	12,164	12,164	12,164
Thermal Design Flow, Loop gpm	93,600	93,600	93,600	93,600
Reactor 10^6 lb/hr	139.4	139.4	142.9	142.9
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	8.6(2)	8.6(2)	8.6(2)	8.6(2)
Reactor Coolant Temperature, °F				
Core Outlet	625.2	625.2	608.7	608.7
Vessel Outlet	620.0	620.0	603.2	603.2
Core Average	593.0	593.0	575.1	575.1
Vessel Average	588.4	588.4	570.7	570.7
Vessel/Core Inlet	556.8	556.8	538.2	538.2
Steam Generator Outlet	556.6	556.6	538.0	538.0
Steam Generator				
Steam Temperature, °F	547.2(3)	546.5	528.3	527.5
Steam Pressure, psia	1022(3,4)	1016(4)	872(4)	867(4)
Steam Flow, 10^6 lb/hr total	15.96/14.78(3,5)	15.95/14.78(5)	15.85/14.69(5)	15.84/14.68(5)
Feed Temperature, °F	446/390	446/390	446/390	446/390
Moisture, % max.	0.1	0.1	0.1	0.1
Tube Plugging, %	0	5	0	5
Zero Load Temperature, °F	557	557	557	557

HYDRAULIC DESIGN PARAMETERS		
Minimum Measured Flow, gpm total	382,630	
Mechanical Design Flow, gpm	109,200	

Notes:

1. Parameters reflect Framatome RSG, Model 73/19T.
2. Core bypass flow includes 2.3% due to TPR and IFMs.
3. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 1033 psia, steam temperature of 548.6°F and steam flow of 15.96×10^6 lb/hr total should be assumed. This is to cover the possibility that the plant could operate with better than expected SG performance with the RSGs.
4. 11 psi SG internal pressure drop incorporated.
5. Steam flow values correspond to feedwater temperatures of 446°F and 390°F, respectively.

3 NSSS DESIGN AND AUXILIARY EQUIPMENT TRANSIENTS

3.1 NSSS DESIGN TRANSIENTS

This section discusses the generation of nuclear steam supply system (NSSS) design transients for Callaway Replacement Steam Generator (RSG) Program. The NSSS design transients were reviewed to determine if they could be used for RSG conditions. This review shows that, with some clarifications, the NSSS design transients remain applicable for the RSG conditions. The transient curves for the RSG were provided to all system and component designers for use in their specific analyses and evaluations for the RSG.

3.1.1 Introduction and Background

As part of the original design and analyses of the NSSS components for Callaway, NSSS design transients (i.e., temperature, pressure, and flow transients) were specified for use in the analyses of the cyclic behavior of the NSSS components. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients selected for use in component fatigue analyses are representative of operating conditions that would be considered to occur during plant operations of possible significance to component cyclic behavior due to their severity or frequency. The selected transients are representative of plant transients which, when used as a basis for component fatigue analyses, would provide confidence that the component was acceptable for its application over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

3.1.2 Input Parameters and Assumptions

The NSSS design transients are based primarily on the NSSS design parameters as discussed in Section 2.1 of this report.

3.1.3 Description of Analyses and Evaluations

The current NSSS design transients for Callaway were based on conservative NSSS design parameters. Therefore, if the current design parameters (Thot, Tcold, Tsteam, and feedwater temperature) bound the Callaway RSG design parameters, then the current NSSS design transients will also be applicable for the Callaway RSG Program.

The RCS primary-side temperatures (Thot and Tcold) for the RSG are identical to those assumed in the current transients. The NSSS design transients are based on the thermal design flow (TDF). The TDF is also identical to that assumed.

The minimum (lower end) steam pressure assumed in the current design transients is 807 psia, which bounds the Callaway RSG minimum design steam pressure of 867 psia. The minimum steam pressure conditions (that is, 5-percent steam generator tube plugging (SGTP) level condition) produce the largest parameter deviation for the NSSS design transients. Therefore, the current design transients remain bounding for the Callaway RSG. The maximum (upper end) steam pressure assumed in the current design transients is 950 psia, which is 66 psi lower than the Callaway RSG maximum design steam pressure of 1,016 psia. Again, since the lower steam pressure is limiting (produces largest parameter deviation) for the NSSS design transients, the current design transients remain bounding for the Callaway RSG. However, necessary adjustments to the curves are made to address the higher steam pressure for the RSG.

The minimum (lower end) feedwater temperature assumed in the current design transients is 390°F, which is the same as for the RSG. The maximum (upper end) feedwater temperature assumed is also identical to the Callaway RSG parameters. There are minor differences in the steam flow with the Callaway RSG. These differences will have no significant impact on the NSSS design transients.

There are some minor differences between the Framatome Model 73/19T RSGs and the Westinghouse Model F current steam generators. The effect of these differences on the NSSS design transients is insignificant.

Based on the comparison of design parameters and the above evaluation, it is concluded that the current NSSS design transients remain applicable for the Framatome Model 73/19T RSG.

3.1.4 Acceptance Criteria and Results

The NSSS design transients are input to the primary- and secondary-component structural and fatigue analysis/evaluations. The final acceptance is determined by the component stress and fatigue analyses presented in Section 5.

3.1.5 Conclusions

Consistent with the current NSSS design transients, the NSSS design transients for the RSG are conservative representations of transients which, when used as a basis for component fatigue analyses, provide confidence that the component is appropriate for its application over the operating license period of the plant. Also, consistent with the original NSSS design transients, the number of transient occurrences are based on an operating license period of 40 years.

3.2 AUXILIARY EQUIPMENT DESIGN TRANSIENTS

3.2.1 Introduction

The Callaway auxiliary equipment design specifications included transients that were used to design and analyze the class 1 auxiliary nozzles connected to the reactor coolant system (RCS) and certain nuclear steam supply system (NSSS) auxiliary systems piping, heat exchangers, pumps, and tanks. These transients are described by variations in pressure, fluid temperature, and flow. They represent umbrella cases for operational events postulated to occur during the plant lifetime. To a large extent, the transients are based on engineering judgment and experience and are considered to be of such magnitude and/or frequency as to be significant in the component design and fatigue evaluation processes. The transients are sufficiently conservative such that, when used as a basis for component fatigue analysis, they provide confidence that the component will perform as intended over the operating license period of the plant.

For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

As part of the Callaway RSG Program, the auxiliary equipment design transients were reviewed to assess continued applicability.

3.2.2 Input Parameters and Assumptions

The review of the auxiliary equipment design transients was performed based on the range of NSSS design parameters developed to support the RSGs (shown previously in Table 2-1).

The approved range of NSSS design parameters for the RSG was compared with the NSSS design parameters used to develop the current design-bases transients. The current design-bases transients for Callaway are contained in Reference 1.

3.2.3 Description of Analyses and Evaluation

An evaluation of the current design transients was performed to determine which transients could be potentially affected by the RSG. The evaluation concluded that the only design transients that could be potentially impacted by the RSG are those temperature transients affected by full-load RCS (Tcold) design temperatures.

These temperature transients are defined by the differences between the temperature of the coolant in the RCS loops and the temperature of the coolant in the auxiliary systems connected to the RCS loops. The greater the temperature difference, the greater the impact these temperature transients have on auxiliary component design and fatigue evaluation processes. Since the design coolant temperatures in the auxiliary systems are not affected by the RSG, the temperature difference between the coolant in the auxiliary systems and the coolant in the RCS loops is only impacted by changes in the RCS design temperatures.

The current design temperature transients are based on a full-load Tcold of 560°F. This full-load temperature was assumed for equipment design to ensure that the temperature transients would be conservative for a wide range of NSSS design parameters.

3.2.4 Acceptance Criteria and Results

A comparison of the range of NSSS design temperatures for the RSG Program at full-load (that is Tcold between 538.2° and 556.8°F) with the Tcold value used to develop the current design transients indicates that the RSG temperature range is lower. These lower full-load design temperatures result in less severe transients, since the temperature differences between RCS loop temperatures and the lower design temperatures in the auxiliary systems connected to the RCS are less. For example, the temperature transients imposed on the chemical and volume control system letdown and charging nozzles associated with starting and stopping letdown and charging flow would be less severe, since the temperatures assumed for the RSG Program (538.2° to 556.8°F) are less than the 560°F considered for the original transients. Therefore, the current body of auxiliary design transients is conservative for the RSG design parameters.

3.2.5 Conclusions

The only auxiliary equipment transients that can be potentially impacted by the RSG are those temperature transients related to full-load NSSS design temperatures. A review of these temperature transients indicates that, if these transients were based on the RSG design parameters, they would be less severe. Therefore, the current auxiliary equipment design transients for Callaway remain bounding for the revised RSG design conditions. These transients are used as the basis for the evaluation of all the NSSS auxiliary equipment, as discussed in Section 5 of this report.

3.2.6 References

1. Westinghouse Systems Standard Design Criteria (SSDC) Document 1.3X, Rev. 0, September 1998.