October 12, 2001

Mr. James Scarola, Vice President
Shearon Harris Nuclear Power Plant
Carolina Power & Light Company
Post Office Box 165, Mail Code: Zone 1
New Hill, North Carolina 27562-0165

SUBJECT: SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1 - ISSUANCE OF AMENDMENT RE: STEAM GENERATOR REPLACEMENT AND POWER UPRATE (TAC NOS. MB0199 AND MB0782)

Dear Mr. Scarola:

The Nuclear Regulatory Commission has issued Amendment No. 107 to Facility Operating License No. NPF-63 for the Shearon Harris Nuclear Power Plant, Unit 1 (HNP), in response to your request dated October 4, 2000, for the Steam Generator Replacement (SGR) and December 14, 2000, for an approximate Power Uprate (PU). These applications were supplemented by letters dated March 8, 2001, March 27, April 26, May 14, May 18, June 4, June 11, June 26, June 29, July 3, July 16 (2 letters), July 17, August 17, and September 20, 2001.

The SGR application requested a license amendment that allows HNP operations with Westinghouse Model Delta 75 steam generators (SGs), replacing the current HNP W Model D4 SGs. The PU application allows the HNP operations at a maximum power level of 2900 megawatts thermal (MWt) (an approximate 4.5 percent increase from the current licensed power of 2775 MWt).

This amendment also revises the accident analyses to adopt the alternate source term (AST) methodology, using the guidance of Nuclear Regulatory Commission Regulatory Guide 1.183.

A copy of the related Safety Evaluation is enclosed. Notice of Issuance will be included in the Commission's regular bi-weekly Federal Register notice for the SGR and AST portions of this amendment. With respect to the portion of this amendment related to the PU, a Notice of Issuance will be forwarded to the Office of the Federal Register for publication.

Sincerely,

/RA/
N. Kalyanam, Acting Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-400

Enclosures:
1. Amendment No. 107 to NPF-63
2. Safety Evaluation
3. Notice of Issuance for PU portion of amendment

cc w/enclosures:
See next page

cc:

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A copy of the related Safety Evaluation is enclosed. Notice of Issuance will be included in the Commission's regular bi-weekly Federal Register notice for the SGR and AST portions of this amendment. With respect to the portion of this amendment related to the PU, a Notice of Issuance will be forwarded to the Office of the Federal Register for publication.

Sincerely,

/RA/
N. Kalyanam, Acting Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-400

Enclosures:
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Subject to comments

OGC NLO	D:DLPM	AD:NRR	OD:NRR	
AFernandez	JZwolinski	BSheron	JJohnson for/SCollins	
10/02/01	10/10/01	10/11/01	10/12/01	
YES/NO	YES/NO	YES/NO	YES/NO	

The SEs from the following technical Branches were incorporated without any major change

DSSA/SRXB	DSSA/SPSB	DE/EMCB	DE/EMEB	DSSA/SPLB	DE/EEIB	DIPM/IOLB
FAkstulewicz	MReinhart	ESullivan/ KWichman	KManoly	GHubbard	AMarinos/ CHolden	DTrimble
03/15/01/ 08/14/01	08/24/01	08/27/01	09/10/01/ 09/10/01	09/06/01	07/27/01/ 03/05/01	07/11/01

CAROLINA POWER & LIGHT COMPANY, et al.

DOCKET NO. 50-400

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 107
License No. NPF-63

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

   A. The application for amendment by Carolina Power & Light Company, (the licensee), dated October 4, 2000, for the Steam Generator Replacement, and December 14, 2000, for an approximate Power Uprate, as supplemented March 8, 2001, March 27, April 26, May 14, May 18, June 4, June 11, June 26, June 29, July 3, July 16 (2 letters), July 17, August 17, and September 20, 2001, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications, as indicated in the attachment to this license amendment; and paragraph 2.C.(2) of Facility Operating License No. NPF-63 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 107, are hereby incorporated into this license. Carolina Power & Light Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA by Jon R. Johnson for/
Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

Attachments:
1. License page 4
2. Changes to the Technical Specifications

Date of Issuance: October 12, 2001

ATTACHMENT TO LICENSE AMENDMENT NO. 107

FACILITY OPERATING LICENSE NO. NPF-63

DOCKET NO. 50-400

Replace the following pages of License No. NPF-63 and the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

License

Remove Page	Insert Page
4	4

Technical Specifications

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Index page xiii	Index page xiii
1-2a	1-2a
1-5	1-5
2-2	2-2
2-4	2-4
2-5	2-5
2-7	2-7
2-8	2-8
2-9	2-9
2-10	2-10
B 2-1	B 2-1
B 2-6	B 2-6
3/4 1-11	3/4 1-11
3/4 2-14	3/4 2-14
3/4 3-28	3/4 3-28
3/4 3-30	3/4 3-30
3/4 3-31	3/4 3-31
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3/4 3-34	3/4 3-34
3/4 4-2	3/4 4-2
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3/4 4-16a	---
3/4 4-17	3/4 4-17
3/4 4-19	3/4 4-19
3/4 4-20	3/4 4-20
3/4 4-20a	3/4 4-20a
3/4 4-29	3/4 4-29
3/4 4-30	3/4 4-30
3/4 4-31	3/4 4-31
3/4 7-2	3/4 7-2
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B 3/4 1-3	B 3/4 1-3
B 3/4 2-6	B 3/4 2-6
B 3/4 4-1	B 3/4 4-1
B 3/4 4-2	B 3-4 4-2
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B 3/4 4-5	B 3/4 4-5
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B 3/4 7-2	B 3/4 7-2
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6-19c	6-19c
6-24a	6-24a
6-24b	6-24b
6-24c	6-24c

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 107 TO FACILITY OPERATING LICENSE NO. NPF-63

CAROLINA POWER & LIGHT COMPANY

SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-400

1.0 INTRODUCTION

By letter dated October 4, 2000 (Ref. 1), Carolina Power & Light Company (CP&L, the licensee) submitted a request for changes to the Shearon Harris Nuclear Power Plant, Unit 1 (HNP) Facility Operating License and Technical Specifications (TS). The application requested a license amendment that allows HNP operations with Westinghouse Model Delta 75 steam generators (SGs), replacing the current HNP W Model D4 SGs. The Model Delta 75 SGs have thermally treated alloy 690 tube material, which would increase corrosion resistance compared to the Inconel 600 tube material in the Model D4 SGs. The replacement with the Model Delta 75 SGs is to avoid corrosion and cracking of SG tubes similar to that experienced at other plants with similar Model D SGs. In conjunction with the SG replacement (SGR) application, the licensee also proposed to increase the normal reactor coolant average temperature (T_{avg}) from 580.8^{o}F to 588.8^{o}F.

By letter dated December 14, 2000 (Ref. 2), the licensee submitted a power uprate (PU) application requesting HNP operations at a maximum power level of 2900 megawatts thermal (MWt) (an approximate 4.5 percent increase from the current licensed power of 2775 MWt).

The applications for SGR and PU were supplemented by letters dated March 8, 2001, March 27, April 26, May 14, May 18, June 4, June 11, June 26, June 29, July 3, July 16 (2 letters), July 17, August 17, and September 20, 2001. These supplements contained clarifying information only, and did not change the initial no significant hazards consideration determination, or expand the scope of the initial application.

In the July 17, 2001, letter, as supplemented August 17, 2001, CP&L proposed to revise the analyses of radiological consequences previously provided by Ref. 1 and Ref. 2. Regulatory Guide (RG) 1.183 provides guidance on application of alternative source terms (ASTs) in revising the accident source terms used in the design basis radiological consequences analyses, as allowed by Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.67. The licensee used the AST methodology as established in RG 1.183 to calculate the offsite and control room radiological consequences for HNP to support the increase of the control room unfiltered leakage.

The two amendment requests are intertwined very closely and the subjects overlap considerably. In view of this, the staff is issuing one amendment for both applications. The review of both applications was done by various technical disciplines and the Safety Evaluation (SE) is arranged by areas of review, as listed below:

Section 2.0 Transient and Accident Analyses Evaluation
Section 3.0 Radiological Consequences
Section 4.0 Pressure Vessel Fluence Evaluation
Section 5.0 Component and Structural Integrity
Section 6.0 Systems, Structures, and Components Evaluation
Section 7.0 Balance of Plant Systems
Section 8.0 Electrical Power
Section 9.0 Instrumentation and Control Systems
Section 10.0 Human Factors

2.0 TRANSIENT AND ACCIDENT ANALYSES EVALUATION

2.1 Background

In support of the SGR and PU applications, the licensee submitted a transient and loss-of-coolant accident (LOCA) analysis, and proposed TS changes (Refs. 1 and 2) to the Nuclear Regulatory Commission (NRC) for the staff to review and approve.

The licensee has reanalyzed the design basis transients and LOCAs to address its compliance with the applicable licensing criteria and requirements for the SGR and PU applications. The staff's review is to confirm that the licensee performs safety analyses with acceptable methods, to verify that the analytical results meet the required acceptance criteria, and to ensure that the proposed TS appropriately reflect the results of the acceptable safety analyses. The following evaluation is based on the staff review of the licensee's safety analysis, proposed TS changes (Refs. 1 and 2) and the licensee's response (Refs. 4 and 5) to the staff Request for Additional Information (RAI). This evaluation includes the staff's review of the following areas: (1) analytical methods, (2) LOCA analysis, (3) transient analysis, and (4) proposed TS changes.

2.2 Analytical Methods

The methods used for the LOCA and non-LOCA analyses are discussed in Sections 6.1.1.2 and 6.1.2.2 of Ref. 3 and the response to RAI 1 of Ref. 4. The small break LOCA (SBLOCA) and large break LOCA (LBLOCA) analyses have been performed with the NRC previously approved Siemens Power Corporation (SPC) evaluation models (EMs) (Refs. 7, 8, and 9). The EMs consist of the following computer codes:

- RELAP4-EM for determination of hydraulic parameters for the reactor coolant system (RCS) and safety injection flow during the blowdown phase of an LBLOCA

- REFLEX for calculation of the RCS behavior during the reflood phase of an LBLOCA

- ANF-RELAP for calculation of the hydraulic parameters of the reactor coolant primary system and secondary side of the SGs during an SBLOCA

- RODEX2 for calculation of the initial fuel stored energy, fission gas release and fuel cladding gap conductance during an LBLOCA or SBLOCA, and

- TOODEE2 for determination of the fuel rod heatup during an LBLOCA or SBLOCA.

The non-LOCA analysis is performed with the NRC-approved SPC methodology (Ref. 10). The approved methods for the non-LOCA analysis include the following computer codes:

- ANF-RELAP (Ref. 10) for a simulation of the RCS and calculations of RCS parameters such as core power, RCS flow, and primary and secondary temperatures and pressures during a non-LOCA transient

- XCOBRA-IIIC (Refs. 11 and 12) for a simulation of the hot channel thermal-hydraulic analysis and determination of the departure from nucleate boiling ratios (DNBRs) using the approved critical heat flux (CHF) correlations; and

- XTGPWR (Ref. 13) for calculation of axial and radial power distributions and reactivity feedback functions.

In response to the staff's question regarding compliance with the conditions specified in the staff's SEs for the referenced methodologies, the licensee stated in Ref. 4 that, in January 1999, it conducted an on-site assessment of Framatome-ANP's (FRA-ANP, formerly Siemens Power Corporation) follow-through of the plan and commitments outlined in its February 24, 1998, response to the NRC addressing FRA-ANP's compliance with SE restrictions. The licensee's on-site review confirmed that FRA-ANP had identified, clarified with the NRC, and implemented the identified methodology commitments and restrictions into FRA-ANP engineering analysis and design procedures. For the analysis to support the PU and SGR applications, the licensee specified to FRA-ANP that the methods and models used must be reviewed and approved methodologies. During the licensee's oversight of the LOCA and non-LOCA analysis, the licensee continued to follow FRA-ANP analysis issues, including procedure maintenance activities that implement the FRA-ANP commitment to identify and meet SE restrictions. As a result, the licensee confirmed that a specific calculation section entitled "SER Restrictions," prepared by FRA-ANP in safety analyses, had clearly addressed each identified methodology restriction for applicable calculations. Based on the results of the licensee's on-site review of FRA-ANP's programs to follow the SE restrictions and the analysis for PU and SGR applications to show the compliance with the SE restrictions, the staff concludes that the licensee has provided reasonable assurance to ensure that the SE conditions (contained in Refs. 7, 8, 9, and 10) for use of the methodologies are met.

2.2.1 Methods for DNBR Calculations

As described in Section 7.1.2 of Enclosure 6 to Ref. 1, the licensee calculated DNBRs with XCOBRA-IIIC for SPC high temperature performance (HTP) fuels using the HTP CHF correlation. For the steamline break event that resulted in thermal-hydraulic conditions outside the range analyzed for the HTP correlation, the licensee calculated DNBRs using the Biasi correlation for SPC HTP fuels. The safety DNBR limits have been imposed by the licensee to assure that there is at least a 95 percent probability at a 95 percent confidence that the hot rod in the core does not experience a DNB during transients. The staff finds that the XCOBRA-IIIC code, CHF correlations and the associated safety DNBR limits are the NRC-approved methods

(Refs. 12 and 14) for calculating the DNBRs for the SPC HTP fuel. Therefore, the staff concludes that the licensee's methods for DNBR calculations are acceptable.

2.2.2 Event Classification

The licensee assigned initial events to the following categories in accordance with Chapter 15 of NUREG-0800, "Standard Review Plan (SRP) for the Safety Analysis Reports for Nuclear Power Plants": (1) increase in heat removal by the secondary system, (2) decrease in heat removal by the secondary system, (3) decrease in RCS flow, (4) reactivity and power distribution anomalies, (5) increase in reactor coolant inventory, and (6) decrease in reactor coolant inventory.

The licensee classified the design basis events according to their anticipated frequency of occurrence identified as Condition I normal operation and operational transients; Condition II faults of moderate frequency; Condition III infrequent faults; and Condition IV limiting faults. In Table 6.2.0-1 of Ref. 3, the licensee listed the design basis events evaluated or analyzed under Conditions II, III and IV. The staff finds that the classification of these events is consistent with the guidance of the SRP and current licensing practices, with the exception of the complete loss of forced reactor coolant flow event and withdrawal of a rod cluster control assembly (RCCA) event are listed in the Table as Condition III events with the SRP acceptance criteria that allow failure of a small fraction of the fuel in the core. The event categorization is inconsistent with SRP 15.3.1 and 15.4.3 that classify the complete loss of forced reactor coolant flow event and withdrawal of an RCCA event as Condition II events with the acceptance criteria that require no violation to the DNBR safety limits. Nonetheless, the licensee has analyzed the complete loss of forced reactor coolant flow as presented in Section 6.2.15 of Ref. 3 to satisfy the acceptance criteria for a Condition II event. Thus, the staff concludes that the licensee's approach for the analysis of the complete loss of reactor coolant flow event is acceptable.

The withdrawal of an RCCA event was allowed to be classified as a Condition III event for reactors manufactured by Westinghouse because of its very low probability of occurrence (WCAP-9272-A, "Westinghouse Reload Safety Evaluation Methodology"). Since the HNP has a reactor manufactured by Westinghouse, the licensee's classification of the withdrawal of an RCCA event as a Condition III event is consistent with the current licensing practices, and is acceptable.

2.2.3 Transients and LOCA Analyses

The licensee analyzed LOCA and non-LOCA transients and discussed the analysis in Ref. 3. The licensee analyzed and identified the limiting case for each event category discussed in Chapter 15 of the Final Safety Analysis Report (FSAR) with consideration of the effects of changes in values of plant parameters (such as an increase in the core power, increases in SG primary side volume and heat transfer area, reduction in the core peaking factors, and changes in the setpoints for the reactor trips and engineered safety actuation systems) on plant transients and accidents. For the transient and LOCA analysis that supports the PU and SGR applications, the licensee considered the following plant conditions:

- A maximum core power of 2900 MWt (increased from the current core power of 2775 MWt),

- A full-power normal T_{avg} of 588.8^{0}F (increased from 580.8^{0}F),
- The reactor coolant volume of 10,300 cubic feet at a nominal T_{avg} of 588.8^{0}F (increased from 9,410 cubic feet at a nominal T_{avg} of 580.8^{0}F to reflect a larger primary SG volume),
- A 3 percent SG tube plugging and a smaller secondary SG volume,
- The revised values of setpoints for the engineered safety features actuation systems (Table 2.2 of Ref. 6) and reactor trips (Table 6.2.0-3 of Ref. 3),
- Design core bypass flow of 7.1 percent of the core flow (increased from the current value of 6.3 percent),
- A core with all SPC HTP fuel, and
- A total peaking factor of 2.41 (decreased from the current value of 2.52) and a nuclear enthalpy rise factor of 1.66 (decreased from the current value of 1.73.)

The required minimum RCS flow specified in the current TS was used as the total RCS flow in the analysis (Enclosure 3 of Ref. 4). For each transient, the licensee considered the limiting single failure. The limiting single failure for each transient was selected on an event-specific basis. While a loss of offsite power (LOOP) was chosen, the timing of a LOOP and events analyzed with a LOOP were consistent with the current transient and accident analysis in the FSAR.

2.3 LOCA Analysis

The licensee has performed the LOCA analysis and documented the results in Sections 6.1.1 through 6.1.4 of Ref. 3. The staff's evaluation of the LBLOCA, and SBLOCA analysis and post-LOCA long-term cooling analysis is as follows.

2.3.1 Large Break LOCA Analysis

The licensee analyzed LBLOCA events and presented the results of the original analysis in Section 6.1.1 of Ref. 3. Subsequently, the licensee submitted to NRC the results of an LBLOCA reanalysis in Ref. 2 for the staff to review. The reanalysis corrected an error in the calculation of normalized axial power shape in the original analysis. The licensee stated that in the reanalysis there were no changes to methods or assumptions. The methods used were the NRC-approved SPC evaluation models. The analysis included the following assumptions: (1) the power level at 102 percent of the uprated power, (2) a 3 percent SG tube plugging, (3) a total peaking factor of 2.41 and a nuclear enthalpy rise factor of 1.66, and (4) the maximum reactor vessel average coolant temperature of 588.8^{0}F (increased from 580.8^{0}F). The licensee assumed that a LOOP occurred simultaneously with the LOCA. For assessment of the effect of axial power shapes on the LOCA calculational results, the licensee considered both (1) beginning of cycle (BOC) stored energy with both BOC and middle-of-cycle (MOC) axial power shapes, and (2) MOC stored energy with an end of cycle (EOC) axial shape. For single failure considerations, the licensee considered the loss of a diesel generator and a loss of the low head safety injection pump (LHSIP) in the analysis, and determined that the loss of the

low-pressure safety injection (LPSI) resulted in the most limiting peak cladding temperature (PCT), and therefore, was the limiting single failure event.

The licensee analyzed eight LOCA cases for slot and guillotine breaks with the break sizes up to a full double-ended break. The results show that the worst case is the double-ended-cold-leg guillotine break with a discharging factor of 0.8, an MOC axial power and BOC stored energy. The analysis for the worst case shows that the calculated PCT is 2090°F, the maximum localized oxidation is 7.58 percent of the total cladding thickness, and the maximum hydrogen generation is less than one percent of the total amount of zircaloy in the core.

These results meet the acceptance criteria of 10 CFR 50.46: the calculated PCT of less than 2200°F; the maximum localized oxidation of less than 17 percent; and the maximum hydrogen generation of less than one percent. Therefore, the staff concludes that the LBLOCA analysis is acceptable.

2.3.2 Small Break LOCA Analysis

The licensee performed the SBLOCA analysis with the NRC-approved SPC SBLOCA evaluation models and included the results in Section 6.1.2 of Ref. 3. The analysis included the following assumptions: (1) the power level at 102 percent of the uprated power, (2) a 3 percent SG tube plugging, (3) a total peaking factor of 2.41 (decreased from the current limit of 2.52) and a nuclear enthalpy rise factor of 1.66 (decreased from the current limit of 1.73), and (4) the maximum reactor vessel average coolant temperature of 588.8^{0}F (increased from 580.8^{0}F.) The worst single failure identified was the loss of a diesel generator with a coincident LOOP assumed to occur simultaneously with a reactor trip. In order to determine the limiting size break, the licensee performed analyses for SBLOCA events for breaks of 2.0, 3.0 and 4.0-inch diameter in the pump discharge cold-leg. The analysis shows that the results of the limiting case of a 3-inch break meet the acceptance criteria specified in 10 CFR 50.46: the calculated PCT is less than 2200°F, the highest localized oxidation is less than 17 percent, and the total oxidation is less than 1 percent. Therefore, the SBLOCA analysis is acceptable.

2.3.3 Post-LOCA Long-Term Cooling (LTC) Analysis

The licensee performed an analysis to determine the effects of the PU and SGR applications on post-LOCA LTC, and described the results in Section 6.1.3 of Ref. 3. The analysis determined the minimum mean sump boron concentrations (MMSBC) required to maintain a post-LOCA subcritical core. For the MMSBC calculations, the licensee assumed that all available LOCA boron sources (including the refueling water storage tank (RWST), the RCS, the accumulators, various emergency core cooling systems (ECCSs), and containment spray system (CSS) piping) to the sump were at minimum volumes, liquid inventories and boron concentrations, while assumed that all boron diluted sources (including the containment spray additive tank and associated piping and the deactivated boron injection tank and associated piping) to the sump were at maximum volumes, liquid inventories, and minimum (0 ppm) boron concentration. The staff finds that the assumptions made in the analysis result in higher values for the required MMSBC and are conservative; therefore, the staff concludes that the calculated MMSBC values are acceptable for use to maintain a subcritical core during post-LOCA conditions.

2.3.4 Post-LOCA Hot-Leg Switchover (HLSO) Analysis

The licensee performed a post-LOCA HLSO analysis and presented the results in Section 6.1.4 of Ref. 3. The methods used for the analysis were consistent with the Westinghouse methods used for the current HLSO analysis in the FSAR. The analysis determined: (1) the maximum allowable HLSO time to prevent boron precipitation, and (2) the minimum allowable HLSO time to ensure sufficient injection flow and preclude a reduction of the core liquid inventory following the HLSO. The results show that allowable range of the HLSO time is from 3 hours to 8.5 hours. The staff finds that the required HLSO time of 6.5 hours documented in the current FSAR 6.3.2.5.2.3 is within the allowable range of the HLSO times calculated for the PU and SGR applications. Therefore, the staff concludes that the current required HLSO time remains acceptable to prevent boron precipitation and ensure sufficient injection flow for a post-LOCA core.

2.4 Non-LOCA Transient Analysis

The licensee analyzed the design transients with the NRC-approved methods: the ANF-RELAP code for the calculations of RCS response and the XCOBRA-IIIC code for the DNBR calculations, and documented the analysis in Sections 6.1.5, 6.2, 6.3 and 6.8 of Ref. 3. The staff discusses its evaluation of the transient analysis for each event in the following sections.

2.4.1 Control Rod Assembly Ejection

The licensee analyzed the control rod assembly ejection event using the approved computer codes: XTGPWR for calculations of rod worth and power peaking factors, ANF-RELAP for the RCS response calculations, and XCOBRA-IIIC for DNBR calculations. The input parameters and the associated uncertainties assumed in the analysis were consistent with the current analysis in the FSAR. The licensee also used the methods documented in SPC Topical Report (TR) XN-NF-78-44(A), “A Generic Analysis of Control Rod Ejection Transient for Pressurized Water Reactors,” for determination of the pellet energy deposition. Two sets of cases were analyzed by the licensee for this event: one initiated at hot full power (HFP) and one initiated at hot zero power (HZP). Both of these cases were analyzed using BOC and EOC kinetics. The results show that the peak pellet enthalpy remains below the limit of 280 cal/gm. The licensee’s analysis also identified that the limiting DNBR occurred at the HFP with the BOC kinetics, and the limiting fuel centerline temperature occurred at the HZP with the EOC kinetics. For both limiting cases, the calculated DNBRs and fuel centerline temperatures are within the safety limits, thus ensure no fuel failure during this event. The results meet the acceptance criteria of SRP 15.4.8, and therefore, are acceptable.

2.4.2 Decrease in Feedwater Temperature

The licensee’s analysis for the limiting case was based on initial full power conditions with a decrease in feedwater temperature caused by the inadvertent opening of a low pressure feedwater heater bypass valve. The decreased feedwater temperature event resulted in an increase in thermal load less than the 10 percent thermal load increase assumed in the increased steam flow event. Therefore, this event was bounded by the increased steam flow event. The staff review of the analysis for the increased steam flow event is discussed below in Section 2.4.4 of this evaluation.

2.4.3 Increase in Feedwater Flow

The increased feedwater flow event was assumed to initiate from a full-open main feedwater valve. The licensee analyzed the following HFP cases with conditions of: (1) a minimum (BOC) reactivity feedback and automatic rod control, (2) a maximum (EOC) reactivity feedback and manual rod control and (3) a maximum reactivity feedback and automatic rod control. The HZP case was assumed to initiate from a step change in main feedwater flow from 0 to 120 percent with a maximum reactivity and manual rod control.

The analysis shows that the results meet the acceptance criteria of SRP 15.1.2. Specifically, the calculated peak RCS primary and secondary pressures are below 110 percent of the design pressures, and the calculated DNBRs remain above the DNBR safety limit; therefore, the analysis is acceptable.

2.4.4 Increase in Steam Flow

The licensee analyzed two increased steam flow cases with a 10 percent step load increase from the rated power conditions: one case with a minimum neutronics feedback (BOC) and the other case with maximum neutronics feedback (EOC). Both cases were analyzed with automatic rod control. During the course of the review, the staff requested the licensee to perform an additional analysis to show that the cases with the automatic rod control were more limiting than the cases without automatic rod control. In response, the licensee analyzed two additional cases with manual rod control for both BOC and EOC core conditions, and confirmed (RAI 15 of Ref. 5) that the case with automatic rod control and BOC conditions resulted in the lowest DNBR, and therefore, was the limiting case.

For all the cases analyzed, the results show that the calculated peak RCS primary and secondary pressures are less than 110 percent of the design pressures, and the calculated minimum DNBR remains above the DNBR safety limit. These results meet the acceptance criteria of SRP 15.1.3; therefore, the analysis is acceptable.

2.4.5 Inadvertent Opening of a SG Relief Valve or Safety Valve

The licensee analyzed this event based on initial full power conditions with an increase in steam flow caused by the inadvertent opening of an SG relief, safety or dump valve. This event was initiated with a maximum steam flow through a credible SG valve, which was less than 10 percent of the rated steam flow assumed in the analysis of the increased steam flow event. Therefore, the results of this event were bounded by the increased steam flow event. The staff's evaluation of the analysis of the increased steam flow event is discussed above in Section 2.4.4.

2.4.6 Steam System Piping Failure Inside and Outside of Containment

The steamline break (SLB) event was analyzed for cases initiated from the HFP and HZP conditions with a maximum break size. The maximum break is a double-ended-guillotine break in a main steamline outside containment between the flow restrictor at the SG outlet nozzle and the main steam isolation valve (MSIV). Both cases with and without LOOP were analyzed. In response to the staff's question concerning compliance with the restrictions on the use of the NRC-approved SLB methodology, the licensee stated (RAI 16 of Ref. 4) that it complied with

the restrictions on use of the NRC-approved methods documented in TR EMF-84-093(A) Revision 1. The licensee used the following conservative input assumptions for the SLB analysis: (1) the core conditions with a maximum worth control rod stuck in a fully withdrawn position to maximize a radial peaking factor, (2) EOC core conditions to yield the maximum negative moderator reactivity feedback, (3) an assumed steam blowdown through the break to maximize the cooldown effect, and (4) a limiting single failure assuming failure of one of two high head safety injection (HHSI) pumps to delay the transport of boron to the core.

The analysis identified that the worst case, resulting in a lowest DNBR, was an SLB initiated from HZP conditions with offsite power available and with a stuck rod. The results of the limiting SLB case show that, due to the low DNBR, no fuel failure is predicted to occur.

The SLB analysis uses acceptable methodology and the results are within the acceptable criteria of SRP 15.1.5 that allows failure of a small fraction of fuel rods in the core for an SLB event. Therefore, the analysis is acceptable.

2.4.7 Loss of External Electrical Load, Turbine Trip, Closure of the MSIVs and Loss of Condenser Vacuum

The loss of load event was assumed to initiate with the loss of external electrical load that resulted in automatic closure of the turbine control valves. The turbine trip event was initiated with a turbine trip that resulted in rapid closure of the turbine stop valves. Since the turbine stop valves closed more rapidly than the turbine control valve, the turbine trip event resulted in a more severe transient than the loss of load event.

An inadvertent closure of the MSIVs resulted in a complete loss of steam flow similar to the turbine trip. Since the turbine stop valves closed more rapidly than the MSIVs, the turbine trip event resulted in a more severe transient.

A loss of condenser vacuum event precluded the use of steam dump to the condenser and resulted in a turbine trip. The licensee's analysis of the turbine trip event neglected the direct reactor trip resulting from a turbine trip signal and took no credit for steam dump to the condenser. Therefore, the analysis of the turbine trip event bounded the loss of load event, an inadvertent closure of MSIVs event and the loss of condenser vacuum event. The staff's evaluation of the analysis for the turbine trip event is discussed below.

The licensee analyzed three turbine trip cases with the BOC kinetics to maximize the increase in reactor power during the transient. The licensee assumed a complete loss of steam load from full power without a direct reactor trip signal from any of the sensors on the turbine stop valves. During the transient, the reactor was tripped from trip signals other than the turbine trip signal. The assumptions used for the three cases were consistent with the current analysis in the FSAR to maximize the RCS primary and secondary pressurization and minimize the calculated minimum DNBR.

For all the cases analyzed, the results show that the calculated DNBRs are above the safety DNBR limit, and the RCS primary and secondary pressures remain below 110 percent of the design pressures. The results meet the acceptance criteria of SRP 15.2.3; therefore, the analysis is acceptable.

2.4.8 Loss of Non-Emergency Alternating Current (AC) Power to Station Auxiliaries

The complete loss of non-emergency AC power (LOAC) was assumed to initiate from a completed loss of the offsite grid accompanied by a turbine-generator trip. An LOAC event resulted in the loss of all power to station auxiliaries, including the reactor coolant pumps. A loss of power to all reactor coolant pumps caused a reduction in coolant flow through the reactor core. The reduced coolant flow rate resulted in an increase in the average coolant temperature and a decrease in the margin to DNB. During the event, loss of main feedwater occurred on turbine trip. The decreased main feedwater to the SGs decreased the primary-to-secondary system heat transfer rate and resulted in an increase in the RCS coolant average temperature and pressure.

The licensee performed the analysis of this event with the approved ANF-RELAP computer code. The input parameters and the associated uncertainties assumed in the analysis reflected the plant operating conditions for PU and SGR applications, and were consistent with the current analysis in the FSAR. The single failure assumption was the loss of the turbine-driven auxiliary feedwater (AFW) pump, with no credit given to one of the two motor-driven AFW pumps.

The results show both the RCS primary and secondary system pressures remain below 110 percent of the design pressures and the calculated DNBRs are above the DNBR safety limit. The results meet the acceptance criteria of SRP 15.2.6; therefore, the analysis is acceptable.

2.4.9 Loss of Normal Feedwater Flow

The loss of normal feedwater flow event was assumed to initiate from a trip of the main feedwater pumps or a malfunction in the feedwater control valves, which resulted in a total loss of all main feedwater flow to the SGs. The loss of main feedwater flow decreased the subcooling margin in the secondary side downcomer, which decreased the RCS primary-to-secondary system heat transfer and led to an increase in the RCS primary coolant temperature. The increased primary coolant temperature caused overpressurization of the RCS.

The licensee performed the analysis of this event with the approved ANF-RELAP computer code. The input parameters and the associated uncertainties assumed in the analysis reflected the plant operating conditions for PU and SGR applications, and were consistent with the current analysis in the FSAR.

The results of the analysis show that the calculated DNBRs for this event are bounded by the turbine trip (RAI 13 of Ref. 4) and are greater than the safety DNBR limit, and the peak RCS primary and secondary pressures do not exceed the 110 percent of the design pressures. The pressurizer is not predicted to go water solid and the assumed minimum motor-driven AFW flow is sufficient to prevent SG dryout and to accomplish long-term decay heat removal. The results meet the acceptance criteria of SRP 15.2.7; therefore, this analysis is acceptable.

2.4.10 Feedwater System Pipe Breaks Inside and Outside Containment

The licensee performed the analysis of the feedline break (FLB) event with the approved ANF-RELAP computer code. This event was assumed to initiate from HFP conditions with an assumed double-ended guillotine break of the main feedwater line adjacent to the SG. The

most limiting single failure, failure of the available turbine-driven AFW pump, was included in the analysis (RAI 5 of Ref. 4). The FLB cases with and without LOOP were analyzed. A sensitivity study was also performed to determine the worst time for the occurrence of LOOP to maximize the calculated peak RCS pressure. The input parameters and the associated uncertainties for the analysis reflected the plant operating conditions for PU and SGR applications, and were consistent with the current analysis in the FSAR. The analysis identified the following two limiting cases: (1) for an FLB with offsite power available, the limiting case was the HFP case with BOC kinetics, a maximum HHSI and failure of the turbine-driven AFW pump, and (2) for an FLB with LOOP, the limiting case was the HFP case with EOC kinetics and a maximum HHSI and failure of the turbine-driven AFW pump.

The results for the FLB analysis show that the calculated peak RCS pressure is less than 110 percent of the design pressure, and meets the acceptance criteria of SRP 15.2.8. Therefore, the analysis is acceptable.

2.4.11 Partial and Complete Loss of Forced Reactor Coolant Flow

The partial loss of reactor coolant flow event was assumed to initiate from the mechanical or electrical failure in an RCP or a fault in an RCP bus. The complete loss of reactor coolant flow event was initiated from a simultaneous loss of electrical supplies to all RCPs. At initiation of the events, the RCP began to coast down. Since a loss of all RCPs resulted in a larger amount of RCS flow reduction and greater rate of flow decrease, the complete loss of RCS flow event resulted in a more severe transient than the partial loss of RCS flow event. Therefore, the analysis of complete loss of flow event bounded the partial loss of flow event.

Two cases were analyzed for the complete loss of reactor coolant flow event initiated from the HFP conditions: one for a reactor trip actuated by the pump power supply undervoltage trip, and the other for a reactor trip actuated by the pump power supply underfrequency trip with a maximum grid frequency decay rate of 5 Hz/sec. In addition, a 70 percent power case was analyzed to verify that the full-power cases were limiting. The licensee analyzed the event using the approved computer codes ANF-RELAP and XCOBRA-IIIC. The input parameters and associated uncertainties assumed for this analysis were consistent with the current analysis in the FSAR.

The results of the analysis identify that the limiting case is the underfrequency event with a moderator temperature coefficient of 0.0 pcm/^{0}F. For the limiting case, the results show that the calculated DNBRs are greater than the DNBR safety limit and the fuel centerline temperatures are less than the melting temperature limit. The results of the analysis for the complete loss of RCS flow event meet the SRP 15.3.2 acceptance criteria; therefore, the analysis is acceptable.

2.4.12 RCP Locked Rotor and RCP Shaft Break

The locked rotor event was assumed to initiate from an instantaneous seizure of an RCP rotor. The RCP shaft break event was initiated from the instantaneous shearing of an RCP shaft. During the events, the RCS flow through the affected loop rapidly reduced. The flow reduction resulting from the locked rotor event was more severe than that for an RCP shaft break; however, the potential for flow reverse was greater for the RCP shaft break. For both events, the RCS temperature increased because of the reduced RCS flow. The increased RCS

temperature and reduced RCS flow resulted in an increase in the RCS pressure and a decrease in a margin to the DNB.

The licensee analyzed two cases for both events: one case was for RCS overpressurization, and one case was for a decreased DNBR. The approved computer codes ANF-RELAP and XCOBRA-IIIC were used for the analysis. The input parameters and associated uncertainties assumed for this analysis were consistent with the current analysis in the FSAR.

The analysis identifies that the limiting event is the locked rotor event. The results of the analysis for the locked rotor event show that the peak primary and secondary pressures remain within the design limit of 110 percent of the design pressures. Although DNB is predicted to occur, the calculated failed fuel rods are less than 5.1 percent of fuel rods in the core. The results meet the acceptance criteria of SRP 15.3.3 that allow failures of a small fraction of the fuel rods during a locked rotor event. Therefore, the analysis is acceptable.

2.4.13 Uncontrolled RCCA Bank Withdrawal from a Subcritical or Low Power Startup Condition

This analysis was performed with the NRC-approved codes: ANF-RELAP for calculations of system response, and XCOBRA-IIIC for DBNR calculations. The case was analyzed at HZP conditions with BOC neutronics conditions. One RCP was assumed inoperable to minimize the RCS flow. The input parameters and the associated uncertainties assumed in the analysis were consistent with the current analysis in the FSAR.

The analysis shows that the minimum DNBR remains greater than the safety DNBR limit and the maximum fuel centerline temperatures predicted to occur are less than the melting temperature limit. The results meet the SRP 15.4.1 acceptance criteria; therefore, the analysis is acceptable.

2.4.14 Uncontrolled RCCA Bank Withdrawal at Power

To identify the limiting case, the licensee analyzed this event for cases with both minimum and maximum reactivity coefficients at power levels of 60 and 100 percent of uprated power and with reactivity insertion rates ranging from 0 to 100 pcm/sec. This analysis was performed with the NRC-approved codes ANF-RELAP and XCOBRA-IIIC. The input parameters and the associated uncertainties assumed in the analysis were consistent with the current analysis in the FSAR.

The analysis identified (RAI 20 of Ref. 4) that the limiting case is the full-power case with the reactivity insertion rate of 27.6 pcm/sec for EOC neutronics conditions. The results of the limiting case show that the calculated peak RCS primary and secondary pressures are less than 110 percent of the design pressures, and the calculated DNBRs are above the DNBR safety limit. The staff finds that the results have met the SRP 15.4.2 acceptance criteria; therefore, they are acceptable.

2.4.15 Control Rod Misoperation

Control rod misoperation events were assumed to initiate from: (1) a dropped full-length RCCA, (2) a statistically misaligned RCCA, and (3) withdrawal of a single full-length RCCA. The licensee analyzed the three control rod misoperation events using the approved computer codes: XTGPWR for calculations of rod worth and power peaking factors; ANF-RELAP for the

system response calculations; and XCOBRA-IIIC for DNBR calculations. The input parameters and the associated uncertainties assumed in the analysis were consistent with the current analysis in the FSAR.

The results show that for the event with a dropped full-length RCCA or a statistically misaligned RCCA, the calculated peak RCS primary and secondary pressures are less than 110 percent of the design pressures, and the calculated DNBRs remain above the DNBR safety limit. The staff finds that the results have met the SRP 15.4.3 acceptance criteria and concludes the results are acceptable.

For the withdrawal of a single full-length RCCA event, the staff finds that the licensee's categorization of the event as a Condition III is consistent with the current practice for the Westinghouse plants (WCAP-9272-A), and concludes the event categorization is acceptable. The analysis shows that for this event, fuel failure resulting from the fuel experiencing DNB is less than 0.64 percent of the fuel in the core. The results meet the acceptance criterion for a Condition III event that allows failures of a small fraction of the fuel rods in the core. Therefore, the analysis of the withdrawal of a single full-length RCCA is acceptable.

2.4.16 Startup of an Inactive RCP at an Incorrect Temperature

The licensee did not analyze this event at Modes 1 and 2 because the current TS do not allow operation with an RCS loop out of service for Modes 1 and 2.

In Modes 3 through 6, the reactor is subcritical and there is no significant load on the plant. The potential for significant reactivity excursion during this event is very small. The licensee used the analysis for the event of the uncontrolled RCCA bank withdrawal from a subcritical condition to bound the inactive RCP startup event at Modes 3 through 6. The staff evaluation of the analysis for the event of the uncontrolled RCCA bank withdrawal from a subcritical condition is discussed above in Section 2.4.13.

2.4.17 Uncontrolled Boron Dilution

In SRP 15.4.6, the staff requires that at least 15 minutes is available from the time the operator becomes aware of the unplanned boron dilution event to the time a total loss of shutdown margin occurs during Modes 1 through 5. A warning time of 30 minutes is required during Mode 6. The licensee analyzed the uncontrolled boron dilution events at Modes 1 through 5 using the methods consistent with the methods for the current analysis in the FSAR. The input parameters and the associated uncertainties used in the analysis were consistent with the analysis of the record. The analysis of deboration events initiated from each of Modes 1 through 5 shows that Mode 1 gives the shortest available time for detecting and terminating the event. The minimum possible time required to reach criticality for Mode 1 is 16.6 minutes (RAI 22 of Ref. 4), which is greater than the required time of 15 minute specified in SRP 15.4.6.

The administrative controls require that for the plant in Mode 6, all valves that connected to systems that may inject unborated water to be locked in the closed position. The controls will preclude the deboration event from occurring during Mode 6. Therefore, this event is not analyzed for Mode 6. Since results of the licensee's analysis show that sufficient time is available to meet the SRP 15.4.6 requirements, the analysis is acceptable.

2.4.18 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position

The licensee analyzed this event using the approved computer codes: XTGPWR for calculations of rod worth and power peaking factors, and XCOBRA-IIIC for DNBR calculations.

The fuel misloading events was assumed to initiate from full power for cases with the following conditions: (1) interchange of an exposed assembly with another exposed assembly, (2) interchange of an exposed assembly with a fresh assembly, and (3) interchange of fresh assemblies with different enrichment and/or burnable absorber characteristics. The results of the analysis show that for each case analyzed, less than 4 percent of the fuel is predicted to fail based on the DNBR criterion and less than 2 percent of the fuel is predicted to fail based on the fuel centerline melting temperature limit. The analytical results have met the SRP 15.4.7 acceptance criteria that allow failures of a small fraction of fuel rods in the core for a fuel assembly misloading event. Therefore, the analysis is acceptable.

2.4.19 Inadvertent Operation of ECCS (IOECCS) During Power Operation

The original description for the analysis for this event discussed in Section 6.2.26 of Ref. 3 is applicable only for operations at the current licensed power with the replaced SGs. The licensee has reanalyzed this event for PU and SGR applications and described the analysis in Enclosure 4 of Ref. 2. The following evaluation is based on the staff's review of the licensee's reanalysis.

The licensee analyzed this event with the approved ANF-RELAP computer codes. The boron reactivity feedback model from the approved SLB methodology was implemented to ANF-RELAP for this analysis. In this boron model, the negative reactivity associated with the boron injection was delayed until the borated water reached to the top of the core. This delay increased potential for higher core power levels that resulted in a lower minimum DNBR. Therefore, the boron model used in this analysis is conservative and acceptable.

Three cases were analyzed for this event. Two cases were performed to determine the minimum DNBRs with BOC and EOC kinetics. For both cases, the event was initiated from full power and an average temperature of 588.8^{0}F to minimize the initial DNBR margin. The third case was performed to determine pressurizer overfill and the thermal-hydraulic conditions at the pressurizer power-operated relief valve (PORV) and safety relief valve (SRV) inlets.

The results of the analysis for the first two cases show that the calculated DNBRs increase during the transient, and thus do not impose a challenge to the safety DNBR limit. The analytical results for the third case show that the calculated peak RCS primary and secondary pressures are less than 110 percent of the design pressures. The analysis also shows that the calculated inlet pressures and temperatures required for the PORV and SRV to operate in a water environment are within the valve operable ranges, and thus ensure that the PORV and SRV are operable during the transient. The valve operable ranges were previously determined by the licensee to support operability of the PORV and SRV during the discharge of subcooled water in accordance with the NUREG-0737 II.D.1 requirements.

Since the analysis meets the acceptance criteria of SRP 15.5.1 with respect to the RCS pressure limit and the DBNR limit, the analysis is acceptable.

2.4.20 Charging and Volume Control System (CVCS) Malfunction that Increases Reactor Coolant Inventory

This event was assumed to initiate from an operator error, or an erroneous electrical signal that resulted in the inadvertent operation of the charging pumps. This event resulted in an increase in RCS inventory. The response of RCS pressure and temperature of this event was similar to the IOECCS event that was initiated by the inadvertent of the charging pumps. The licensee analyzed the IOECCS event to bound this event for RCS pressurization consideration.

For both this event (Section 6.2.27 of Ref. 3) and the deboration event (Section 6.2.23 of Ref. 3), the malfunction of the CVCS that resulted in an increase in unborated water to the RCS through the charging pumps created a significant challenge to the required shutdown margin in the core. Since the initiating event was the same for malfunction of the same plant components, a decrease in the rate of the reactivity shutdown margin for both events in Sections 6.2.23 and 6.2.27 (Ref. 3) was equivalent. Therefore, the licensee analyzed the CVCS malfunction resulting in a deboration event (Section 6.2.23) to bound Section 6.2.27 consideration of the adequate shutdown margin. The results of the staff's evaluation of the deboration event and the IOECCS event are discussed above in Sections 2.4.17 and 2.4.19 of this evaluation, respectively.

2.4.21 Inadvertent Opening of a Pressurizer Pressure Safety Valve (PSV) or PORV

This event was assumed to initiate from an inadvertent opening of a pressurizer PSV or PORV, which resulted in blowdown of the reactor coolant through the faulted valve. During the transient, the RCS pressure rapidly decreased until the pressurizer liquid was depleted. The decreased RCS pressure and inventory caused a challenge to the DNBR safety limit. The licensee analyzed this event using the approved computer codes ANF-RELAP for the system response calculations, and XCOBRA-IIIC for DNBR calculations. The analysis assumed a steam flow rate from the pressurizer equivalent to the maximum flow capacity for one PSV, resulting in a maximum depressurization rate. The input parameters and the associated uncertainties assumed in the analysis were consistent with the current analysis in the FSAR.

Since the calculated RCS primary and secondary pressures are within 110 percent of the design pressures and the calculated minimum DNBR is greater than the DNBR safety limit, the staff concludes that the results of the analysis meet the SRP 15.6.1 acceptance criteria, and therefore, are acceptable.

2.4.22 Steam Generator Tube Rupture (SGTR) Transient

As indicated in Section 6.3 of Ref. 3, the licensee analyzed the SGTR event and showed that the consequences of the radiological releases met the acceptance criteria specified in SRP 15.6.3. For the radiological release calculations, the licensee assumed that water overfill in the ruptured SG would not occur during an SGTR event. For the PU and SGR applications, the licensee analyzed two SGTR cases. One was for SG-overfill calculations to confirm adequacy of the radiological release calculations by showing no SG overfill to occur, and the other was for mass release analysis to determine the total mass release for use in the radiological release calculations.

2.4.22.1 SG Overfill Analysis

The licensee performed the SG-overfill analysis with the approved LOFTTER2 computer code and methods documented in TR Report WCAP-10698-A, “SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill.” The event was assumed to initiate with a double-ended break of one SG tube located at the top of the tube sheet on the outlet (cold-leg) side of the SG. At initiation of an SGTR, the reactor was assumed at full power. A LOOP was assumed following the reactor trip and the highest worth control assembly was assumed to be stuck in its fully withdrawn position at the reactor trip. The worst single failure, the failure of a main steam power-operated relief valve (MSPORV) on one of the two intact SGs to open on demand, was included in the analysis to maximize the reduction in a margin to the SG overfill. The additional assumptions used to minimize the margin to the SG overfill included: a maximum (10 percent) SG tube plugging; a simulation of turbine runback based on the calculated reactor trip time; a conservative high initial SG secondary mass; and the conservative high AFW flow to the ruptured SG. These assumptions for the initial plant conditions are either consistent with or more restrictive than the current SG-overfill analysis in the FSAR.

The operator actions for the SGTR recovery provided in the HNP emergency operating procedures (EOPs) number EOP-path 2 were modeled in this analysis. The operator actions modeled included identification and isolation of the ruptured SG, cooldown and depressurization of the RCS to restore the inventory, and termination of safety injection (SI) to stop primary-to-secondary leakage. The corresponding operator action times used in the analysis were listed in Table 6.3.1-1 of Ref. 3. The action times were determined by the licensee based on its STGR EOP and verified by the results of the licensee’s simulator tests (RAI 25 of Ref. 4).

The analysis shows that the peak ruptured SG water volume of 5285 ft^3 is less than the secondary volume of the replaced SG, and thus demonstrates that the SG overfill will not occur in the ruptured SG during an SGTR event. Since approved methods are used for the analysis, the assumptions are consistent with the current SG-overfill analysis in the FSAR, operator actions and the associated required times are based on the plant EOPs, and the results show no SG overfill to occur in the ruptured SG, the staff concludes that the SG-overfill analysis is acceptable to support the adequacy of the radiological release analysis for an SGTR event.

2.4.22.2 Mass Release Analysis

The licensee performed the mass release analysis for an SGTR with the LFTTR2 code and most of the plant conditions and assumptions used for the SG-overfill analysis. The major assumptions different from the SG-overfill analysis included: no SG tube plugging; no simulation of turbine runback; a conservative low initial SG secondary mass; and the conservative low AFW flow to the ruptured SG. When calculating the fraction of break flow that flashed to steam, 100 percent of the break flow was assumed to come from the hot-leg side of the break.

The operator actions and associated required times used in the SG-overfill analysis were also used in the mass release analysis. The worst single failure, the failed-open MSPORV on the ruptured SG at the time the ruptured SG was isolated, was included in the analysis to maximize the mass releases. Before proceeding with the recovery operations, the failed-open MSPORV was assumed to be isolated by locally closing the associated block valve. It was assumed that

the ruptured MSPORV was isolated at 20 minutes after the valve was assumed to fail open. The assumption for the operator action time of 20 minutes is consistent with the current SGTR analysis (RAI 26 of Ref. 5).

The analysis shows that for the case with power level at 2912.4 MWt, approximately 138,300 lbm of steam is released to the atmosphere from the ruptured SG within the first 2 hours. After 2 hours, 35,100 lbm of steam is released to the atmosphere from the ruptured SG. A total of 167,900 lbm of the RCS primary water is transferred to the secondary side of the ruptured SG before the break flow is terminated. A total of 10,843 lbm of this break flow is calculated to flash to steam upon entering the SG.

For the case with power level at 2787.4 MWt, the results indicate that approximately 135,700 lbm of steam is released to the atmosphere from the ruptured SG within the first 2 hours. After 2 hours, 34,400 lbm of steam is released to the atmosphere from the ruptured SG. A total of 165,400 lbm of the RCS primary water is transferred to the secondary side of the ruptured SG before the break flow is terminated. A total of 10,598 lbm of this break flow is calculated to flash to steam upon entering the SG.

Since approved methods are used for the analysis, the assumptions are consistent with the current mass release analysis in the FSAR, and the operator actions and the associated required times are based on the plant EOPs, the staff concludes that the calculated mass releases are acceptable for use in the radiological release analysis for an SGTR event.

2.4.23 Anticipated Transient Without Scram (ATWS)

An ATWS event is defined as an anticipated operational occurrence (such as loss of normal feedwater, loss of condenser vacuum, or LOOP) combined with an assumed failure of the reactor trip system to shut down the reactor. For the pressurized water reactors (PWRs) manufactured by Westinghouse, the basic requirements of the ATWS rule are specified in paragraph (c)(1) of 10 CFR 50.62. The licensee satisfies the ATWS rule by installing the NRC-approved ATWS Mitigating System Actuation Circuitry (AMSAC).

The licensee performed an analysis to assess the effects of the PU and SGR applications on the current ATWS licensing basis analysis documented in Section 15.8 of the FSAR, which referenced the applicable ATWS analysis discussed in Westinghouse TR WCAP-8330, “Westinghouse Anticipated Transient Without Trip Analysis.” Based on the methods for the current ATWS analysis, the licensee used control-grade equipment to mitigate consequences and used nominal system performance characteristics in the analysis of this event. The conditions of moderator temperature coefficients assumed in the analysis were consistent with those supporting the current licensed plant operation of the HNP. The new AMSAC setpoint was assumed at 20 percent of the SG narrow range span with a timing delay of 25 seconds.

The analysis was performed with the approved computer codes LOFTRAN (WCAP-7907-A) for the system response calculations, and NOTRUMP (WCAP-10079-A) for the SG response simulation. The limiting cases previously identified in the licensing ATWS analysis, the loss of normal feedwater and loss of load ATWS event, were reanalyzed.

The results show that the calculated peak RCS pressure is within the American Society of Mechanical Engineers (ASME) Service Level C Stress level specified as the limit in the current

licensing ATWS analysis. Since the results of the ATWS satisfy the acceptance criterion specified in the current licensing ATWS analysis, the staff concludes the ATWS analysis is acceptable.

2.5 Technical Specification Changes

The licensee submitted to the NRC the proposed TS changes (Refs. 1 and 2) in its support of safe operations of the HNP plant with replaced SGs and at a maximum power level of 2900 MWt. The following is the staff review of the TS changes.

2.5.1 TS 1.28 - Rated Thermal Power

The TS defines 2900 MWt (increased from 2775 MWt) as the rated thermal power. The TS change is acceptable since the power level of 2900 MWt was considered as the rated power in the acceptable transient and accident analysis for the PU and SGR applications.

2.5.2 TS Figure 2.1-1 and Base 2.1.1- Core Safety Limit Plot, TS 3.2.5.a and TS Base 3/4.2.5 - DNB Parameters

TS Figure 2.1-1 shows plots that represent core operating limits for the combination of thermal power, RCS pressure and T_{avg} to prevent cladding failure caused by exceeding the DNBR safety limit. The proposed Base 2.1.1 deletes the referenced DNB correlations applicable to Westinghouse fuel. Since the revised core operating limits are determined by using the NRC-approved SPC methods listed in TS 6.9.1.6 for uprated power operating conditions with the replaced SGs and SPC-only fuel, the staff concludes that the revised core operating limits in TS figure 2.1-1 and the proposed Base 2.1.1 are acceptable.

TS 3.2.5.a and TS Base 3/4.2.5 change the allowable maximum T_{avg} from 586^0F to 594.8^0F. Since the proposed value for T_{avg} is the maximum initial T_{avg} with uncertainties assumed in the transient and accident analysis, the staff concludes that the proposed changes are acceptable.

2.5.3 TS Table 2.2-1 - Reactor Trip System Instrumentation Trip Setpoints, and Table 3.3-4 - Engineered Safety Features Actuation System Instrumentation Trip Setpoints

TS Tables 2.2-1 and 3.3-4 list the required instrumentation setpoints for a number of reactor trips and engineered safety features actuation systems (ESFAS), respectively. For each required function, the setpoint is specified in terms of the following five items: (1) total allowance (TA) representing the difference between setpoint and safety analysis limit; (2) the “Z” term specifying the statistical summation of analysis errors without inclusion of sensor and rack drift and calibration uncertainties; (3) sensor error (S) characterizing sensor drift and calibration uncertainties; (4) trip setpoint defining a norminal setpoint; and (5) allowable value accommodating the instrument drift assumed between operational tests and the accuracy to which setpoint can be measured and calibrated.

As indicated in Table 2.2-1, the following ten functions of the required 18 reactor trips are affected by the proposed TS: (1) power range (neutron flux - high positive rate); (2) power range (neutron flux - high negative rate); (3) over-temperature delta T; (4) overpower delta T; (5) pressurizer pressure - low; (6) pressurizer pressure - high; (7) pressurizer water level - high;

(8) reactor coolant flow - low; (9) SG water low - low; and (10) SG water level low and low SG level coincident with steam and feedwater flow mismatch.

As indicated in Table 3.3-4, the changes to the ESFAS setpoints involve the following functions: (1) the signal of containment pressure (high-1), pressurizer pressure (low) or steamline pressure (low) that initiates the SI actuation system; (2) the containment pressure (high-3) signal that actuates the containment spray system; (3) the signal of the containment pressure (high-2) or negative steamline pressure rate (high) that actuates the main steamline isolation system; (4) the SG water level (high-high) signal that initiates the turbine trip and feedwater isolation system; (5) the signal of the SG water level (low-low) or SG differential pressure (high) that initiates the AFW system; and (6) the signal of pressurizer pressure (P-11 or not P-11) that initiates the ESFAS interlocks.

Ref. 6 provides a discussion of the setpoint calculations for the reactor trips and the ESFAS, including the methods, assumptions and results. Based on its review of the information included in Ref. 6, the staff finds that the methods used to determine the proposed setpoints are the NRC-approved Westinghouse methods; and the results show that after accounting for applicable channel measurement uncertainties, the required TS trip setpoints are bounded by their corresponding analytical setpoint values (shown in Table 2-2 and 2-3 of Ref. 6) used in the acceptable safety analysis to support the PU and SGR applications. Therefore, the staff concludes that the proposed TS setpoints presented in TS Tables 2.2-1 and 3.3-4 are acceptable.

2.5.4 TS 3.1.2.5 - Borated Water Source - Shutdown and its Associated TS Base 3/4.1.2

The TS specifies the minimum-required borated water volume during shutdown. The TS requirement is to ensure that sufficient borated water sources provide the required shutdown margin after xenon decay and cooldown from 200°F to 140°F. The proposed minimum borated water volume is increased from 6,650 to 7,150 gallons for the boric acid tank with the associated water level of 23 percent (increased from 21%). The revised borated water volume reflects the results of licensee's analysis, accounting for the increased volume of the replaced SGs for maintaining the TS required shutdown margin. Therefore, the revised TS is acceptable.

2.5.5 TS Table 3.7-1 - Maximum Power Range Neutron Flux High Setpoint with Inoperable MSSVs

Operability of all the main steam line safety valves ensures that the secondary system pressure is limited to less than 110 percent of its design pressure during the most severe transient. With less than full main steam safety valves capacity available, operation may be allowed at reduced power levels. TS Table 3.7-1 lists the maximum allowable setpoints for high power range neutron flux trip for conditions with the main steam safety valves inoperable. The revised table lowers the trip setpoints from 53, 35, and 17 percent of the original rated thermal power of 2775 MWt to 50, 33, 16 percent of the uprated power of 2900 MWt for operating conditions with a maximum number of inoperable safety valves of 1, 2 and 3 on any operating SG, respectively. The proposed trip setpoints (in term of MWt) are lower than the setpoints of the current TS, and are more restrictive; therefore, the TS changes are acceptable.

2.5.6 TS 4.4.1.2.2, 4.4.1.3.2, 3.4.1.4.1.b, 4.4.1.4.1.1 and the Associated TS Base 3/4.4.1 - RCS Loop (Modes 3, 4 and 5)

The TS specify the minimum SG secondary water level required for decay heat removal using SGs. A water level above the top of the SG tube bundle is needed to ensure an adequate heat sink. Since the elevation of the level instrument taps relative to the top of the tube bundle is different for the replaced SGs, the values that ensure an appropriate minimum water level is revised. For Modes 3 through 5, the value of the narrow range level (including allowances of instrumentation uncertainties and process measurement errors) is changed from 10 percent to 30 percent of the span. For Modes 4 and 5 operations, the TS specify that the wide range channels shall be used unless they are inoperable and the minimum SG wide range level is not greater than 74 percent of the span. An added paragraph in TS Base 3/4.4.1 clarifies that the surveillance requirement is to ensure the SG water level to be above the top of the SG tubes in order to maintain adequate capability for decay heat removal. The proposed TS reflect the new required water levels for the replaced SGs, and the clarification provided in the associated Base is consistent with the definition specified in the current TS for the required SG water levels for decay heat removal, therefore, the TS changes are acceptable.

2.5.7 TS Base 3/4.7.1.1 - SG Safety Valves

The minimum relieving capacity of the SG safety valves is required to limit the SG secondary side pressure within 110 percent of the design pressure during the most severe design transient. The Base for current TS 3/4.7.1.1 states that the required total relieving capacity of all safety valves on all of the steam lines is 1.36×10^7 pounds/hour (lbs/hr), which is 111 percent of the total secondary steam flow of 12.2×10^6 lbs/hr at 100 percent rated thermal power. For the PU and SGR applications, the proposed TS Base clarifies that the required total capacity of all safety valves is 1.36×10^7 lbs/hr (unchanged), which is in excess of 105 percent of the total secondary steam flow of 12.9×10^6 lbs/hr at 100 percent uprated thermal power. Since the changes reflect the acceptable transient and accident analysis, the proposed TS Base is acceptable.

2.5.8 TS Base 3/4.7.1.2 - Auxiliary Feedwater System

TS Base 3/4.7.1.2 clarifies that the requirement of the minimum AFW pump performance is based on a maximum allowable degradation (changed from a 4-percent degradation specified in the current TS Base) of the pump performance curves. The revised TS Base does not change the current TS Base that requires the minimum AFW flow to be consistent with the assumptions used in the transient and accident analysis, thus, the minimum allowable pump performance remains unchanged. Therefore, the proposed Base is acceptable.

2.5.9 TS Base 3/4.7.1.3 - Condensate Storage Tank

TS 3.7.1.3 specifies a condensate storage tank (CST) to be operable with a contained volume of at least 270,000 gallons of water. The current CST water volume was determined based on current rated power with the assumptions of a hot standby time of 12 hours followed with the longest cooldown time to the residual heat removal (RHR) entry point. For the PU and SGR applications, the licensee's analysis shows (RAI 29 of Ref. 4) that the current TS-required minimum CST water has adequate margin to support a cooldown with a period of 6 hours at hot standby followed with the longest cooldown time to the RHR entry point. The proposed TS

Base 3.7.1.3 clarifies that the required CST water volume will support hot standby for 6 hours instead of the 12 hours hot standby assumed in the current cooldown analysis. The 6-hour period is (1) consistent with the licensee's revised cooldown analysis that accounts for increased volume of the replaced SGs and uprated power of 2900 MWt, and (2) longer than the minimum required time of 4 hours specified in SRP 5.4.7; therefore, the proposed Base is acceptable.

2.5.10 TS 3.10.4.b, 3.4.1.2, and 4.10.4.3 - Special Test Exception (Reactor Coolant Loop)

The special test exception stated in current TS 3.10.4.b and 3.4.1.2 allows the hot rod drop testing during Mode 3 with less than all three reactor coolant pumps (RCPs). The revised TS delete the test exception. Since the licensee will perform the rod drop test only with all three RCPs operating to simulate a reactor trip under actual conditions, the staff concludes that the proposed TS changes to delete the test exception of TS 3.10.4.b and 3.4.1.2, and the corresponding surveillance of TS 4.10.4.3, are acceptable.

2.5.11 TS 5.4.2 - Design RCS Volume

The revised TS 5.4.2 specifies that the total water and steam volume of the RCS is 10,300 (increased from 9,410) cubic feet at a nominal T_{avg} of 588.8 (increased from 580.8) ^{0}F. The proposed RCS increase reflects the design volume of the replaced SGs (with greater number and length of U-tubes) calculated at the proposed nominal T_{avg} of 588.8 ^{0}F. The proposed values are appropriately considered in the acceptable analysis to support the PU and SGR applications; therefore, the revised TS is acceptable.

2.5.12 TS 6.9.1.6 - Core Operating Limits Report

Since the transient and accident analysis for the PU and SGR applications is performed by the SPC for the licensee, the licensee proposes to delete the following three Westinghouse technical reports from TS 6.9.1.6:

17. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985;
18. WCAP-10266-P-A, Rev. 2, "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the Bash Code," March 1987; and
19. WCAP11837-P-A, "Extension of Methodology for Calculating Transition Core DNBR Penalties," January 1990.

The revised TS 6.1.9.6 reflects the appropriate references of analytical methodologies used for the transient and accident analysis to support the PU and SGR applications with installed all-SPC fuel in the core; therefore, the TS is acceptable.

2.6 Summary

The staff has reviewed the licensee's analysis and proposed TS changes to support operations of the HNP plant with the replaced W Model Delta 75 SGs and at a maximum core power level of 2900 MWt. Based on this review, the staff finds that the supporting safety analysis is performed with the previously NRC-approved methods, the input parameters of the analysis adequately represent the plant conditions at the uprated power level and with the replaced SGs, and the analytical results are within the applicable acceptance criteria. Therefore, the staff

concludes that the supporting analyses are acceptable. The staff also finds that the proposed TS changes discussed in Section 2.5 of this evaluation adequately reflect the results of the acceptable supporting analysis, and therefore, concludes that the proposed TS are acceptable for the PU and SG replacement applications.

3.0 RADIOLOGICAL CONSEQUENCES

3.1 Steam Generator Replacement

3.1.1 Background

By letter dated July 17, 2001, (Ref. 15) as supplemented August 17, 2001, (Ref. 16), the licensee revised its radiological consequence analyses of the design basis SGTR accident originally submitted on October 4, 2000 (Ref. 1). In its revised radiological consequence analyses, the licensee proposed full implementation of the AST and revised the offsite and control room operator doses using the proposed AST. The full implementation of the AST would replace the current accident source term used in the design basis radiological consequence analyses with an AST pursuant to 10 CFR 50.67, “Accident Source Term.” As part of the full implementation of the AST, the total effective dose equivalent (TEDE) acceptance criteria in SRP Section 15.0.1 and 10 CFR 50.67 replace the previous whole body and thyroid dose guidelines provided in 10 CFR 100 and GDC 19.

This review is limited to the radiological aspects of the requested SGR as grouped in Ref. 1 as Group III, “Specific Activity and Dose,” and as revised by Ref. 15 and Ref. 16. The staff also reviewed re-analysis of a design basis SGTR accident submitted by the licensee using the AST.

The proposed amendment would, among other things:

(1) Revise TS 3/4.4.8, “Specific Activity” and associated TS Bases to add the reactor coolant specific activity limit of 60 microcuries per gram (µCi/gm) dose equivalent iodine 131 (DEI-131) at all power levels as a single analysis limit, deleting Figure 3.4-1, “Dose Equivalent I-131 Reactor Coolant Specific Activity Limit vs Percent of Rated Thermal Power with the Reactor Coolant Specific Activity >µCi/gram Dose Equivalent I-131.”

(In Ref. 1, the licensee also requested to reduce the current reactor coolant specific activity limit of 1.0 µCi/gm DEI-131 to 0.35 µCi/gm DEI-131. Subsequently, by Ref. 14 and Ref. 15, the licensee withdrew this portion of the request.)

(2) Revise TS 1.11 definition of dose equivalent iodine-131 to read in part,

The thyroid dose conversion factors used for this calculation shall be those listed in the International Commission on Radiological Protection (ICRP), “Limits for Intakes of Radionuclides by Workers,” ICRP Publication 30, Volume 3, No. 1-4, 1979 (or equivalently, Federal Guidance Report No. 11, “Limiting Values of Radionuclides Intake and Air Concentration and dose Conversion Factors for Inhalation, submission, and Ingestion,” EPA 520/1-88-020, September 1988).

3.1.2 Evaluation

The licensee reevaluated the radiological consequences of an SGTR accident, which result from the release of radioactive materials to the environment following the transfer of radioactive reactor coolant to the secondary side of the SG. The total primary-to-secondary leak rate is assumed to be 1.0 gallons per minute (gpm) as specified in the TS, and the leak is assumed to be distributed, with 0.7 gpm to the two intact SGs and 0.3 gpm to the faulted steam generator. The leakage to the intact SGs is assumed to persist for the duration of the accident. The duration of this accident is assumed to be 8 hours. Offsite power is assumed to be lost at the reactor trip; consequently, the main condenser was not available for the steam dump. The licensee performed a thermal-hydraulic analysis to maximize steam break flow and steam release through the ruptured SG PORV.

The iodine transport model used in the licensee's analyses accounts for flashing of the SG break flow, steaming, and iodine partitioning. The model assumes that a fraction of the iodine carried by the break flow immediately becomes airborne as a result of flashing and atomization. All iodine in the flashed break flow becomes airborne and is immediately released to the environment. The remaining fraction of the break flow that is not assumed to become airborne immediately mixes with the secondary water and is assumed to become airborne at a rate proportional to the steaming from the faulted SG.

The licensee analyzed two SGTR accident cases. The first case assumed that a pre-existing iodine spike occurred before the SGTR. For this case, the reactor coolant specific activity was assumed to be at 60 µCi/gm of dose equivalent iodine-131 (DEI-131) as a result of an iodine spike. The secondary coolant iodine specific activity was assumed to be at the secondary coolant specific activity equilibrium value of 0.1 µCi/gm of DEI-131.

For the second case, the licensee assumed that the SGTR event initiated the iodine spike concurrent with the accident. Immediately before the accident, the reactor coolant was assumed to be at the reactor coolant activity level of 1 µCi/gm of DEI-131. The SGTR accident was assumed to initiate an iodine spike that would result in a release of iodine from the fuel gap to the reactor coolant at a rate that is 335 times the normal iodine release rate necessary to maintain the reactor coolant activity level of 1 µCi/gm of DEI-131. The licensee further assumed that the spike continued for 8 hours from the start of the SGTR accident.

In its submittals, the licensee concluded that the release of fission products following the SGTR accident will result in doses that are small fractions of the dose criteria specified in 10 CFR 50.67 for the exclusion area boundary (EAB), low population zone (LPZ), and control room. The staff has reviewed the licensee's analysis and finds that the major assumptions, parameters, and methods used by the licensee for its radiological consequence analyses are consistent with those provided in SRP Section 15.0.1, and RG 1.183 for assessing the radiological consequences of the postulated SGTR accident.

To verify the licensee's analyses, the staff performed a confirmatory radiological consequence dose calculation and compared its results to those calculated by the licensee. Although the staff performed independent calculations to confirm the licensee's results, the staff's acceptance is based on the licensee's analyses. The staff's analysis confirmed the licensee's conclusion that the radiological consequences would not exceed the dose criteria specified in 10 CFR 50.67 for the EAB, LPZ, and control room. The radiological consequences calculated

by both the licensee and the staff are small fractions of the radiation dose criteria set forth in 10 CFR 50.67.

Table 1 provides the radiological consequences for a fuel handling accident (FHA), Table 2 provides the parameters and assumptions used in the radiological consequences calculations in an SGTR accident, and Table 3 provides the parameters and assumptions used in the control room radiological consequences calculations in an SGTR accident.

3.1.3 Summary

The staff concludes that the license amendment requested by the licensee to delete the existing TS Figure 3.4-1 and revise TS 3/4.4.8 is acceptable. The staff further finds that the proposed AST implementation and re-analyses of the design basis SGTR accident using the AST are acceptable. The bases for the staff's acceptance are that the resulting radiological consequences from the postulated SGTR accident are small fractions of the dose criteria specified in 10 CFR 50.67, and that the methodologies used by the licensee for its dose calculations are consistent with the guidelines provided in RG 1.183.

Table 1

Radiological Consequences for
Fuel Handling Accident
(rem as TEDE)

	Pre-Accident iodine Spike	Acceptance Criteria
Exclusion Area Boundary	2.2	25[(1)]
Low Population Zone	0.6	25[(1)]
Control Room	1.6	5.0[(1)]

	Accident-Initiated iodine Spike	Acceptance Criteria
Exclusion Area Boundary	1.3	2.5[(2)]
Low Population Zone	0.4	2.5[(2)]
Control Room	0.9	5.0[(1)]

[(1)] From 10 CFR 50.67
[(2)] From SRP 15.0.1

Table 2

Parameters and Assumptions Used in
Radiological Consequence Calculations
SGTR Accident

Parameter	Value	
Iodine specific activities in primary coolant, µCi/gm		
	Based on 1 µCi/gm of DEI-131	Based on 60 µCi/gm of DEI-131
I-131	0.570	34.20
I-132	0.823	49.38
I-133	2.408	144.48
I-134	0.189	11.34
I-135	0.613	36.78
Primary to secondary leak rates		
Faulted SG, gpm	0.3	
Intact SGs, gpm	0.7	
Leakage duration, hours	8	
Iodine specific activities in primary coolant for pre-accident iodine spike, µCi/gm	60	
Iodine specific activities in primary coolant for accident-initiated iodine spike, µCi/gm	1.0	
Iodine specific activities in secondary coolant, µCi/gm	0.1	
Effective letdown flow rate, gpm	174	
Primary coolant mass, grams	1.73E+8	
Iodine removal rate at equilibrium, per hour	3.59E-3	
Iodine spiking factor	335	
Spiking duration, hours	8	
Iodine spike appearance rates, curie per minute		
I-131	127.6	
I-132	422.4	
I-133	608.4	
I-134	186.3	
I-135	197.3	

Table 2

Parameters and Assumptions Used in
Radiological Consequence Calculations
SGTR Accident
(Continued)

Offsite power	Not available
Main condenser	Not available
Faulted SG	
Break flow, lb	1.68E+5
Flashed break flow, lb	1.08E+4
Iodine partition factors	
Non-flashed	100
Flashed	1.0
Iodine species released to environment, %	
Elemental	97
Organic	3
Atmospheric Dispersion Factors (χ/Q values), sec/m^3	
0-2 hour EAB	6.17E-4
0-8 hour LPZ	1.40E-4
8-24 hour LPZ	1.00E-4
1-4 day LPZ	5.90E-5
4-30 day LPZ	2.40E-6

Table 3

Parameters and Assumptions Used in
Radiological Consequence Calculations
SGTR Accident
Control Room

Volume	7.1+4 ft^3
Normal ventilation flow rates	
Filtered makeup air	0
Filtered recirculation	0
Unfiltered makeup air	1050 cfm [1]
Post-accident recirculation	
Filtered makeup air	0
Filtered recirculation	4000 cfm
Unfiltered makeup air	500 cfm
Initiation time	15 seconds
Pressurization mode	
Filtered makeup air	400 cfm
Filtered recirculation	3600 cfm
Unfiltered makeup air	500 cfm
Initiation time	2 hours
Filter efficiencies	
Elemental	99%
Organic	99%
Particulate	99%
Control room χ/Q Values(sec/m^3)	
0-8 hours	4.08E-3
8-24 hours	1.16E-3
1-4 day	3.25E-4
4-30 day	1.23E-5

[1] cfm - cubic feet per minute

3.2 Power Uprate

3.2.1 Background

To demonstrate that the HNP engineered safety features (ESFs) designed to mitigate the radiological consequences resulting from design basis accidents (DBAs) will remain adequate at the proposed uprated power level of 2900 MWt, the licensee reevaluated the offsite and control room radiological consequences for the following postulated DBAs:

- LBLOCA
- SGTR
- Locked Rotor Accident
- Single RCCA Withdrawal
- LOOP
- Rod Ejection Accident
- SBLOCA
- Main Steamline Break (MSLB)
- FHA
- Letdown Line Break
- Waste Gas Decay Tank Rupture

The licensee submitted the results of its revised offsite and control room dose calculations for the above DBAs, along with the major assumptions and parameters used in its those calculations. As documented in the submittals, the licensee determined that the existing ESF systems at HNP will still provide assurance that the radiological consequences of the postulated DBAs at the EAB, in the LPZ, and in the control room, will remain within the radiation dose acceptance criteria specified in SRP Section 15.0.1 and 10 CFR 50.67.

The staff reviewed the licensee's analyses and performed independent confirmatory radiological consequence dose calculations for the following bounding DBAs:

- LBLOCA
- STGR
- MSLB
- FHA
- Locked Rotor Accident
- Rod Ejection Accident

Table 4 shows radiological consequences calculated by the licensee while Tables 5 through 12 show the major parameters and assumptions used by the licensee for its dose calculations and by the staff for its confirmatory dose calculations. The staff also reviewed the licensee's analyses but did not perform independent dose calculations for the SBLOCA and the letdown line break since the radiological consequences of these accidents at HNP are bounded by those of the LBLOCA. Similarly, the radiological consequences of the single RCCA withdrawal are bounded by the rod ejection accident, and the LOOP is bounded by SGTR and MSLB. The staff also did not perform an independent dose calculation for gas decay tank rupture because the quantity of radioactivity that is allowed to store in each gas decay tank is independent of the reactor power level and accident source term used. The licensee did not propose to change the limits.

3.2.1.1 Large Break LOCA

The current radiological consequence analysis for the postulated LBLOCA using the accident source term described in Technical Information Document (TID)-14844 is provided in the HNP UFSAR Section 15.6.5. In conjunction with its PU license amendment request, the licensee reevaluated the offsite and control room radiological consequences of the postulated LOCA at an uprated power level of 2958 MWt using the AST. The staff reviewed the licensee's analysis and performed independent confirmatory dose calculations for two potential fission product release pathways following the postulated LOCA. Specifically, these pathways are containment leakage and post-LOCA leakage from ESF systems outside containment, as described in Sections 3.5.1.1 and 3.5.1.2, respectively. Section 3.5.1.3 summarizes the staff's conclusions regarding the radiological consequences resulting from the postulated LOCA at HNP.

3.2.1.1.1 Containment Leakage

The current maximum allowable primary containment leakage rate (L_a) is 0.1 percent of containment air weight per day. The staff used this rate for the first 24 hours into the accident, and 0.05 percent of containment air weight per day for the remaining duration of the accident (30 days). Fission product removal in the containment atmosphere is achieved by the CSS and natural deposition of aerosol in the containment. The CSS is an ESF system that is designed to provide containment cooling and fission product removal in the containment atmosphere following the postulated LOCA. The CSS consists of two redundant and independent loops. Each loop has a design spray water flow capacity of 1730 gallons per minute (gpm). The CSS starts automatically on a high containment pressure signal, and is credited for removing fission products starting at 120 seconds into the accident. The CSS initially draws spray water from the RWST. When the RWST drains to a predetermined setpoint level, the CSS automatically switches to recirculation mode and begins drawing spray water from the containment sump. The CSS operation is terminated 4 hours after the start of the accident.

The licensee calculated the elemental iodine removal rate using the methodologies provided in SRP Section 6.5.2, and determined that the removal rate is well above the upper limit specified in the SRP; therefore, the licensee used an elemental iodine removal rate of 20 per hour (upper limit specified in the SRP). The removal of elemental iodine is assumed to be terminated 2 hours after the start of the accident, when it reaches the maximum decontamination factor (DF) of 200 in the containment atmosphere. To calculate the removal for iodine in particulate form, the licensee also used the methodologies provided in SRP Section 6.5.2 and determined that the removal rate is 3.94 per hour, and this value is reduced by a factor of 10 to 0.394 per hour when its DF reaches 50 at 2.5 hours after the start of the accident. The staff finds that these iodine removal rates determined by the licensee are acceptable.

The licensee assumed that, during CSS operation, fission products in particulate form (aerosol) are removed by a natural deposition process in the unsprayed region of the containment atmosphere. After CSS operation is terminated, the licensee further assumed that aerosols are removed by a natural deposition process in both the sprayed and unsprayed regions of the containment atmosphere. In Ref. 15, the licensee proposed an aerosol removal rate of 0.2 per hour until it reaches the maximum DF value of 1000, 16 hours after the start of the accident. The licensee assumed no further aerosol removal after that time. The licensee's proposed aerosol removal rate is based on the containment system experiments that examined aerosol deposition through the natural sedimentation processes reported by the Industry Degraded

Core Rulemaking (IDCOR) program, which was sponsored by the nuclear industry. The staff finds that the proposed aerosol removal rate is unacceptable for the reasons presented in the following paragraph.

RG 1.183 cites NUREG/CR- 6183, “A Simplified Method of Aerosol Removal by Natural Processes in Reactor Containments,” as an acceptable method for addressing natural deposition of aerosols. This method was derived through a correlation of Monte Carlo uncertainty analysis results on the basis of detailed aerosol behavior models under the postulated LOCA conditions. These models considered the uncertainties in aerosol properties and its behavior, containment geometry and configuration, and accident progression. Table 24 of NUREG/CR-6183 provides time-variant aerosol removal rates ranging from 0.0157 to 0.223 per hour with a 10th percentile uncertainty distribution for plants with a reactor core power level of 3000 to 4000 MWt reactor plants.

In Ref. 16, in response to the staff’s RAI, the licensee revised the original proposed aerosol removal rate of 0.2 to 0.1 per hour. The licensee modeled the containment atmosphere as two discrete nodes representing sprayed and unsprayed regions, and assumed that these nodes are mixed by the containment fan cooler (CFC) units. The CFC units are safety-related systems designed to remove energy that is released in the containment following a postulated LOCA (along with the ECCS and the CSS). The CFC units are redundant systems consisting of two trains. Each train is powered from a separate redundant essential bus, and has two CFC units. The staff assumed that only one CFC train will be operational, with a total air mixing flow rate of 6.25E+4 cfm in the containment following the postulated LOCA. The staff accepted the revised aerosol removal value of 0.1 per hour.

3.2.1.1.2 Post-LOCA Leakages from ESF Systems Outside Containment

Any water leakage from ESF components located outside the primary containment releases fission products during the recirculating phase of long-term core cooling following a postulated LOCA. The licensee considered two pathways for ESF component leakage. One is leakage directly to the auxiliary building, and the other is backflow leakage to the RWST.

Containment water recirculation is initiated when the CSS drains the RWST water to the predetermined setpoint about 20 minutes after the start of the accident. The licensee assumed that the leakage to the auxiliary building is less than 2.0 gpm, which is twice the leakage value of 1.0 gpm assumed in the HNP UFSAR for the entire 30-day duration of the accident. The staff finds that the leakage value assumed by the licensee is acceptable. The licensee also assumed that 2 percent of all forms of iodine contained in the leakage is released into the auxiliary building atmosphere, consistent with the current design basis leakage rate assumed in the HNP UFSAR. This assumption is based on the containment sump water pH and the initial sump water temperature. The airborne iodine is assumed to be immediately released to the environment through the reactor auxiliary building emergency exhaust system (RABEES). The RABEES is an ESF system designed to have 95 percent removal efficiencies for iodine in elemental, organic, and particulate forms, and for aerosols. The licensee assumed that 3 percent of the RABEES flow will bypass the high-efficiency particulate air (HEPA) filter and charcoal adsorber in the RABEES. The licensee also postulated that the radioiodine that is available for release to the environment is 97 percent in elemental iodine form, while the remaining 3 percent is in organic iodine form, consistent with RG 1.183.

The licensee assumed that ESF backflow leakage to the RWST is less than 1.5 gpm. In response to the staff's RAI, the licensee stated that this leakage value is based on actual leakage tests performed on a refueling outage interval and, of the last six tests performed, only two showed any backflow leakage to the RWST and the leakage value in those tests ranged from 0.8 to 1.1 gpm. For the air flow out from the RWST to the environment, the licensee used the daily heating and cooling cycle model. This model neglects the effect of the heat sink provided by the mass of water in the RWST, which would moderate the effects of daily temperature variations. Using the minimum and maximum water temperatures of 40°F and 125°F respectively, with 1.5 gpm air displacement associated with the ESF leakage into the RWST, the licensee calculated 5.9 cfm air flow out from the RWST. The staff finds that the leakage and air flow rates used by the licensee are acceptable.

3.2.1.1.3 Radiological Consequences Resulting from an LBLOCA

The staff reviewed the licensee's analyses and finds that the calculational methods used in the radiological consequence assessment for the postulated LBLOCA are acceptable and the radiological consequences calculated by the licensee meet the relevant dose acceptance criteria specified in 10 CFR 50.67. The resulting radiological consequence analyses performed by the licensee for the EAB, LPZ, and control room are provided in Table 4. The major four parameters and assumptions used by the licensee for the postulated LOCA dose calculations and used by the staff for its confirmatory calculations are provided in Table 5. Although the staff performed independent calculations to confirm the licensee's results, the staff's acceptance is based on the licensee's analyses. The staff's analysis confirmed the licensee's conclusion that the radiological consequences would not exceed the dose criteria specified in 10 CFR 50.67 for the EAB, LPZ, and control room operator.

Therefore, the staff finds that the re-analyses of the design basis LBLOCA using the AST are acceptable. The staff further concludes that operating HNP at an uprated power level of 2900 MWt will still provide reasonable assurance that the radiological consequences of a postulated LOCA will not exceed the dose criteria specified in 10 CFR 50.67. The bases for the staff's acceptance are that calculated radiological consequences from the postulated LOCA are within the dose criteria specified in 10 CFR 50.67, and the methodologies that the licensee used for its dose calculations are consistent with the guidelines provided in RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," and SRP Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms."

3.2.1.2 Steam Generator Tube Rupture

The licensee reevaluated the radiological consequences of an SGTR accident, which result from the release of radioactive materials to the environment following the transfer of radioactive reactor coolant to the secondary side of the SG. The total primary-to-secondary leak rate is assumed to be 1.0 gpm as specified in the TS, and the leak is assumed to be distributed, with 0.7 gpm to the two intact SGs and 0.3 gpm to the faulted SG. The leakage to the intact SGs is assumed to persist for the duration of the accident. The duration of this accident is assumed to be 8 hours. Offsite power is assumed to be lost at the reactor trip; consequently, the main condenser was not available for the steam dump. The licensee performed a thermal-hydraulic analysis to maximize steam break flow and steam release through the ruptured MSPORV.

The iodine transport model used in the licensee's analyses accounts for flashing of the SG break flow, steaming, and iodine partitioning. The model assumes that a fraction of the iodine carried by the break flow immediately becomes airborne as a result of flashing and atomization. All iodine in the flashed break flow becomes airborne and is immediately released to the environment. The remaining fraction of the break flow that is not assumed to become airborne immediately mixes with the secondary water and is assumed to become airborne at a rate proportional to the steaming from the faulted SG.

The licensee analyzed two SGTR accident cases. The first case assumed that a pre-existing iodine spike occurred before the SGTR. For this case, the reactor coolant specific activity was assumed to be at 60 µCi/gm of dose equivalent iodine-131 (DEI-131) as a result of an iodine spike. The secondary coolant iodine specific activity was assumed to be at the secondary coolant specific activity equilibrium value of 0.1 µCi/gm of DEI-131.

For the second case, the licensee assumed that the SGTR event initiated the iodine spike concurrent with the accident. Immediately before the accident, the reactor coolant was assumed to be at the reactor coolant activity level of 1 µCi/gm of DEI-131. The SGTR accident was assumed to initiate an iodine spike that would result in a release of iodine from the fuel gap to the reactor coolant at a rate that is 335 times the normal iodine release rate necessary to maintain the reactor coolant activity level of 1 µCi/gm of DEI-131. The licensee further assumed that the spike continued for 8 hours from the start of the SGTR accident.

In its submittals, the licensee concluded that the release of fission products following the SGTR accident will result in doses that are small fractions of the dose criteria specified in 10 CFR 50.67 for the EAB, LPZ, and control room. The staff has reviewed the licensee's analysis and finds that the major assumptions, parameters, and methods used by the licensee for its radiological consequence analyses are consistent with those provided in SRP Section 15.0.1 and RG 1.183 for assessing the radiological consequences of the postulated SGTR accident.

To verify the licensee's analyses, the staff performed a confirmatory radiological consequence dose calculation and compared its results to those calculated by the licensee. The staff's analysis confirmed the licensee's conclusion that the radiological consequences would not exceed the dose criteria specified in 10 CFR 50.67 for the EAB, LPZ, and control room. The radiological consequences calculated by both the licensee and the staff are small fractions of the radiation dose criteria set forth in 10 CFR 50.67.

Therefore, the staff finds that the re-analyses of the design basis SGTR accident using the AST is acceptable. The staff further concludes that approving the licensee's request to operate HNP at an uprated power level of 2900 MWt will still provide reasonable assurance that the radiological consequences of a postulated SGTR accident will not exceed the dose criteria specified in 10 CFR 50.67. The resulting radiological consequences calculated by the licensee are shown in Table 4. The major parameters and assumptions used by the licensee for its dose calculations and the staff for its confirmatory dose calculations are listed in Table 6.

3.2.1.3 MSLB Containment

The licensee reevaluated the radiological consequences of a postulated MSLB occurring outside containment and upstream of the SMIVs using the AST. The radiological

consequences of such an accident bound those of an MSLB inside of the containment. When an MSLB occurs, the SG rapidly depressurizes and releases the initial contents of the SG to the environment. The rapid secondary depressurization causes a reactor power transient, resulting in a reactor trip. The licensee assumed that the faulted SG boils dry in 2 minutes, releasing the entire liquid inventory and dissolved radioiodine through the faulted SG to the environment. The licensee analyzed this hypothetical accident using 0.35 gpm of primary-to-secondary leakage through the faulted SG and 0.65 gpm through the intact SGs.

The licensee's fission product transfer and removal models for the reactor coolant inventory and iodine spiking are the same as those discussed in Section 3.5.2 for the SGTR accident, with the exception that iodine spike results in a release of iodine from the fuel gap to the reactor coolant in an MSLB accident that is 500 times the normal iodine release rate necessary to maintain the reactor coolant iodine activity level of 1 µCi/gm of DEI-131, rather than 335 times as assumed for the SGTR. This difference in the magnitude of the iodine spike is attributable to more rapid and greater pressure transient between the primary and secondary system for the MSLB accident than the SGTR accident.

The staff reviewed the licensee's analysis and finds that the calculational methods used for the radiological consequence assessment are acceptable and that the radiological consequences calculated by the licensee meet the relevant dose acceptance criteria. The resulting radiological consequences calculated by the licensee are shown in Table 4. The major parameters and assumptions used by the licensee and the staff are listed in Table 7.

To verify the licensee's analyses, the staff has performed a confirmatory assessment of the radiological consequences resulting from the postulated MSLB. The staff's analysis confirmed the licensee's conclusion that the radiological consequences would not exceed the dose criteria specified in SRP Section 15.01 and 10 CFR 50.67 for the EAB, LPZ, and control room operator. Therefore, the staff finds that re-analyses of the design basis MSLB using the AST is acceptable. The bases for the staff's acceptance are that the resulting radiological consequences from the postulated MSLB are small fractions of the dose criteria specified in 10 CFR 50.67, and the methodology used by the licensee for dose calculations is consistent with the guidelines provided in RG 1.183.

3.2.1.4 Fuel Handling Accident

The licensee reevaluated the radiological consequences of a postulated FHA occurring either inside or outside of the containment in the fuel building using the AST. In each case, the licensee assumed that all fission products are released directly to the environment within a 2-hour period with no isolation of release paths. In its submittals, the licensee concluded that the release of fission products following an FHA will result in doses that are well within the dose criteria specified in 10 CFR 50.67 for the EAB, LPZ, and control room operator. The licensee reached this conclusion on the basis of the following assumptions and parameters:

- One whole fuel assembly with the highest radial peaking factor is damaged, thereby releasing fission products in the fuel gap into the spent fuel pool water in the containment.

- One whole fuel assembly with the highest radial peaking factor plus 52 boiling water reactor (BWR) fuel assemblies (from Brunswick Steam Electric Plant) stored in the spent fuel are damaged, thereby releasing fission products in the fuel gap into the spent fuel pool water in the fuel handling building.
- A fission product decay period of 100 hours (the time period from reactor shutdown to the first fuel movement) for PWR fuels and 4 years for BWR fuels that are stored in the spent fuel pool.
- An overall DF of 200 for the iodine isotopes in the spent fuel pool, with minimum pool water depth of 22 feet in containment and 21 feet in the fuel handling building.
- A 500 cfm unfiltered air inleakage into the control room.

The staff reviewed the licensee's analysis and finds that the major assumptions, parameters, and methods used by the licensee for its radiological consequence analysis are consistent with those provided in SRP Section 15.0.1 and RG 1.183.

To verify the licensee's analyses, the staff performed a confirmatory radiological consequence dose calculation and compared its results to those calculated by the licensee. The radiological consequences calculated by the staff for the EAB, LPZ, and control room are consistent with those calculated by the licensee. Moreover, the radiological consequences calculated by both the licensee and the staff are well within the radiation dose criteria set forth in 10 CFR 50.67. Therefore, the staff concludes that the HNP design will still provide reasonable assurance that the radiological consequences of a postulated FHA will be well within the dose criteria specified in 10 CFR 50.67. The resulting radiological consequences calculated by the licensee are shown in Table 4, and the major parameters and assumptions used by the licensee and staff are listed in Table 8.

3.2.1.5 Locked Rotor Accident

A reactor primary coolant pump locked rotor accident results from an instantaneous seizure of an RCP rotor, which rapidly reduces the primary coolant flow through the affected reactor coolant loop leading to a reactor trip on a low-flow signal. Fuel rod damage is assumed to occur as a result of this event. The licensee re-analyzed this hypothetical accident assuming that 8 percent of the fuel elements will experience cladding failure, thereby releasing the entire fission product inventory in the fuel gap to the reactor coolant. Additionally, the licensee assumed that 1 percent of the fuel rods will experience centerline melt. The fractions of fission products in the reactor core released from both melted fuel and fuel cladding failure are listed in Table 9. Because of the pressure differential between the primary and secondary sides and the assumed SG tube leakage, fission products are assumed to be released from the primary to the secondary system. The licensee assumed that the primary-to-secondary SG tube leak rate is 1.0 gpm, and portion of this radioactivity is released to the environment through either the atmospheric relief valves or the safety valves.

The licensee's analysis assumed a pre-existing iodine spike in the reactor coolant before the locked rotor accident. Such a condition would raise the reactor coolant activity level to 60 µCi/gm DEI-131. The noble gas and alkali metals group activity concentrations in the reactor coolant were determined on the basis of 1 percent failed fuel. The iodine activity concentration in the secondary system at the time of the locked rotor accident is assumed to be equivalent to the TS limit of 0.1 µCi/gm of DEI-131. The alkali metal activity concentration in the secondary system at the time of the locked rotor accident was assumed to be 10 percent of

that in the primary system. The licensee also used a partition factor of 100 for iodine and alkali metals. The licensee stated that the RHR system will be available for heat removal after 8 hours from the start of the accident, and there will be no further steam release to the environment from the secondary system when the RHR system becomes available.

The staff reviewed the licensee's analysis and performed an independent confirmatory dose calculation. The staff's analysis confirmed the licensee's conclusion that the radiological consequences resulting from the postulated locked rotor accident at uprated reactor core power would not exceed the dose criteria specified in SRP Section 15.0.1 and 10 CFR 50.67 for the EAB, LPZ, and control room operator.

Therefore, the staff finds that the licensee's re-analyses of the design basis locked rotor accident using the AST is acceptable. The bases for the staff's acceptance are that the resulting radiological consequences from the postulated locked rotor accident are small fractions of the dose criteria specified in 10 CFR 50.67, and the methodologies used for the licensee's dose calculations are consistent with the guidelines provided in RG 1.183. The results of the licensee's radiological consequence calculation are provided in Table 4 and the major parameters and assumptions used by the staff and by the licensee in the radiological consequence calculations are listed in Table 10.

3.2.1.6 Rod Ejection Accident

The mechanical failure of a control rod mechanism pressure housing is postulated to result in the ejection of an RCCA and drive shaft. The resultant opening in the pressure vessel allows a release of primary coolant to the containment, with concurrent rapid depressurization of the reactor pressure vessel. The consequences of this mechanical failure are a rapid positive reactivity insertion, together with an adverse core power distribution, possibly leading to localized fuel rod damage.

The licensee assumed that 4 percent of the fuel elements will experience cladding failure, releasing the entire fission product inventory in the fuel cladding gap of these elements, while an additional 2 percent of the fuel rods will experience fuel melting. The licensee also assumed that the release of fission products to the environment will occur via two pathways. The first pathway involves a release of primary coolant to the containment via the spill from the opening in the reactor vessel head, which is then assumed to leak to the environment at the design leak rates of the containment. The licensee did not claim any credit for fission product removal in the containment by either the CSS or natural deposition of iodine, with the exception that the licensee assumed that alkali metals in the containment would be removed by natural deposition at a rate of 0.1 per hour.

In the second pathway, fission products would reach the secondary coolant via the SGs with a maximum total allowable primary-to-secondary leak rate of 1 gpm. The fission product transfer and removal models for this pathway are the same as those described for the locked rotor accident in Section 3.2.1.5 above.

To verify the licensee's assessments, the staff performed independent radiological consequence calculations for each of these pathways for the control rod ejection accident. Although the staff performed independent calculations to confirm the licensee's results, the staff's acceptance is based on the licensee's analyses. The staff's analysis confirmed the

licensee's conclusion that the radiological consequences resulting from the postulated rod ejection accident at uprated reactor core power would not exceed the dose criteria specified in SRP Section 15.0.1 and 10 CFR 50.67 for the EAB, LPZ, and control room operator.

Therefore, the staff finds that the licensee's re-analysis of the design basis locked rotor accident using the AST is acceptable. The bases for the staff's acceptance are that the resulting radiological consequences from the postulated rod ejection accident are well within the dose criteria specified in 10 CFR 50.67, and the methodologies used for the licensee's dose calculations are consistent with the guidelines provided in RG 1.183. The results of the licensee's radiological consequence calculation are provided in Table 4 and the major parameters and assumptions used by the staff and by the licensee in the radiological consequence calculations are listed in Table 10.

3.2.2 Dose to the Control Room Operators

The staff is currently working toward resolving the generic issues related to control room habitability, with a particular focus on the validity of the control room unfiltered air infiltration rates that are commonly assumed in licensees' analyses of control room habitability. Meanwhile, the licensee concluded in this license amendment request that the radiological consequence to the control room operator will meet the dose criterion specified in 10 CFR 50.67 with implementation of the AST, as described in RG 1.183 pursuant to 10 CFR 50.67. In its analysis, the licensee assumed unfiltered air inleakage into the control room ranging from 300 to 500 cfm for various DBAs. The staff finds that these unfiltered air inleakage rates used by the licensee are reasonable and therefore acceptable. However, the staff's acceptance of the licensee's unfiltered air inleakage assumption does not preclude any future generic regulatory actions that may result from the forthcoming resolution of generic control room habitability issues.

3.2.3 Summary

Based on review of licensee's analyses and staff's independent confirmatory radiological consequence dose calculations, the staff concludes that the radiological consequences, as a result of PU license amendment request, to offsite and control room operator will meet the dose criterion specified in 10 CFR 50.67 with implementation of the AST, as described in RG 1.183 pursuant to 10 CFR 50.67.

Table 4

Radiological Consequences
(rem TEDE)

Design Basis Accident	EAB	LPZ	Control Room
LOCA	7.9	5.4	3.1

SGTR			
Pre-accident	2.2	0.6	1.6
Accident-initiated	1.3	0.4	0.9
MSB			
Pre-accident	0.1	0.1	0.4
Accident-initiated	0.7	1.0	2.5
FHA	2.0	0.5	1.4
Locked rotor	1.9	1.4	3.2
Rod ejection	4.0	4.1	4.6

Table 5

Parameters and Assumptions Used in
Radiological Consequence Calculations
Loss-of-Coolant Accident

Parameter	Value
Reactor power	2958 MWt
Containment volume of sprayed region	2.014E+6 ft^3
Containment volume of unsprayed region	3.300E+5 ft^3
Flow rate from sprayed to unsprayed region	6.25E+4 cfm
Flow rate from unsprayed to sprayed region	6.25E+4 cfm
Containment leak rate to environment	
0 - 24 hours	0.1% per day
1 - 30 days	0.05% per day
Spray removal rates	
Elemental iodine	20 per hour
Time to reach DF[(1)] of 200	2 hour
Particulate iodine	3.94 per hour
Time to reach DF[(1)] of 50	2.5 hour
Spray operation	
Initiation time	120 seconds
Termination time	4 hours
Spray flow rate	1730 gpm
Aerosol deposition rate for unsprayed region and sprayed region after spray terminated	0.1 per hour
ECCS leak rate	
to auxiliary building	2 gpm
to RWST	1.5 gpm
ECCS Iodine partition factor	2%
ECCS leak initiation time	20 minutes
Sump volume	3.595E+5 ft^3
Reactor auxiliary building emergency exhaust filter efficiency	
Elemental iodine	95%
Organic iodine	95%
Aerosol (particulate)	95%
Reactor auxiliary building emergency exhaust filter bypass	3.3%
Control room isolation time	15 seconds
Control room unfiltered air inleakage	300 cfm

[(1)] Decontamination factor

Table 6

Parameters and Assumptions
Used in
Radiological Consequence Calculations
Steam Generator Tube Rupture Accident

Parameter	Value
Primary coolant iodine activity prior to accident	
Pre-existing spike	60 µCi/gm DEI-131
	34.2 µCi/gm I-131
Accident-initiated spike	1.0 µCi/gm DEI-131
	0.57 µCi/gm I-131
Secondary coolant iodine activity prior to accident	0.1 µCi/gm DEI-131
	0.057 µCi/gm I-131
Iodine spike (appearance) rate increase	335 times
Duration of accident-initiated spike	8 hours
Steam generator tube leak rate	1.0 gpm total
Steam releases	
Break flow	1.63E+5 lbs
Flashed break flow	1E+4 lbs
Primary coolant mass	3.81E+5 lbs
Secondary coolant mass	9.56E+4 lbs
Iodine partition factors	
Flashed steam	1.0
Non flashed steam	100
Control room isolation time	30 seconds
Control room unfiltered air inleakage	500 cfm

Table 7

Parameters and Assumptions
Used in Radiological Consequence Calculations
Main Steam Line Break Accident

Parameter	Value
Primary coolant iodine activity prior to accident	
Pre-existing spike	60 µCi/gm DEI-131
	34.2 µCi/gm I-131
Accident-initiated spike	1.0 µCi/gm DEI-131
	0.57 µCi/gm I-131
Secondary coolant iodine activity	
prior to accident	0.1 µCi/gm DEI-131
	0.057 µCi/gm I-131
Iodine spike (appearance) rate increase	500 times
Duration of accident-initiated spike	5 hours
Steam generator tube leak rates	
Faulted steam generator	0.35 gpm
Intact steam generators	0.65 gpm
Steam releases	
Faulted steam generator	1.62E+5 lbs
Intact steam generators	
0 to 2 hours	3.86E+5 lbs
2 to 8 hours	8.92E+5 lbs
Duration of activity release	40 hours
Control room isolation time	15 second
Control room unfiltered air inleakage	500 cfm

Table 8

Parameters and Assumptions
Used in
Radiological Consequence Calculations
Fuel Handling Accident

Parameter	Value
Radial peaking factors	
PWR fuel assemblies	1.73
BWR fuel assemblies in spent fuel pool	1.5
Fission product decay period	
PWR fuel assemblies	100 hours
BWR fuel assemblies in spent fuel pool	4 years
Number of fuel rods damaged	
In containment	264
In fuel handling building	314 plus 52 BWR fuel assemblies
Fuel pool water depth	
In containment	22 ft
In fuel handling building	21 ft
Fuel gap fission product inventory	
Noble gases excluding Kr-85	5%
Kr-85	10%
I-131	8%
Iodine except I-131	5%
Fuel pool decontamination factors	
Iodine	200
Noble gases	1
Filter efficiencies	
In containment	None assumed
In fuel handling building	
Elemental	95%
Organic	95%
Particulate	95%
Fuel handling building exhaust system	
filter bypass	1.0%
Duration of accident	2 hours
Control room isolation time	15 seconds
Control room unfiltered air inleakage	500 cfm

Table 9

Parameters and Assumptions
Used in
Radiological Consequence Calculations
Locked Rotor Accident

Parameter	Value
Reactor power	2958 MWt
Radial peaking factor	1.73
Primary coolant iodine activity	60 µCi/gm DEI-131
Secondary coolant iodine activity	0.1 µCi/gm DEI-131
Steam generator tube leak rates	
Faulted steam generator	0.3 gpm
Intact steam generators	0.7gpm total
Fraction of fuel rods failed	8%
Fraction of fuel rod melted	1%
Fraction of fission product in gap	
Iodine-131	8%
Krypton-85	10%
Other iodine and noble gases	5%
Alkali metals	12%
Iodine and alkali metal partition factors	100
Primary coolant mass	4.11E+5 lbs
Secondary coolant mass per steam generator	1.15E+5 lbs
Duration of steam release	8 hours
Steam releases	
0 to 2 hours	3.64E+5 lbs
2 to 8 hours	9.39E+5 lbs
> 8 hours	0
Control room isolation time	15 seconds
Control room unfiltered air inleakage	500 cfm

Table 10

Parameters and Assumptions
Used in
Radiological Consequence Calculations
Control Rod Ejection Accident

Parameters	Values
Reactor power	2958 MWt
Fraction of fuel rods failed	4%
Fraction of fuel melt	2%
Primary coolant activity	60 µCi/gm DEI-131
Secondary coolant activity	0.1 µCi/gm DEI-131
Iodine deposition in containment	None
Alkali metal deposition in containment	0.1 per hour
Containment leak rates	
0 to 24 hours	0.1%
1 to 30 days	0.05%
Primary coolant mass	2.063E+8 gm
Primary to secondary leak rate	1.0 gpm
Iodine partition factor	100
Steam release from secondary	
0 to 2 hours	3.64E+5 lbs
2 to 8 hours	0
Control room isolation time	15 seconds
Control room unfiltered air inleakage	300 cfm

Table 11

Control Room

Parameter	Value
Volume	7.1+4 ft^3
Normal ventilation flow rates	
Filtered makeup air	0
Filtered recirculation	0
Unfiltered makeup air	1050 cfm
Post-accident recirculation	
Filtered makeup air	0
Filtered recirculation	4000 cfm
Unfiltered makeup air	300 to 500 cfm
Initiation time	15 seconds
Pressurization mode	
Filtered makeup air	400 cfm
Filtered recirculation	3600 cfm
Unfiltered makeup air	300 to 500 cfm
Initiation time	2 hours
Filter efficiencies	
Elemental	99%
Organic	99%
Particulate	99%

Table 12

Meteorological Data

Exclusion Area Boundary

Time (hr)	X/Q (sec/m^3)
0-2	6.17E-4

Low Population Zone Distance

Time (hr)	X/Q (sec/m^3)
0-8	1.4E-4
8-24	1.0E-4
24-96	5.9E-5
96-720	2.4E-5

Control Room
(All DBAs except LBLOCA and RWST vent)

Time (hr)	X/Q (sec/m^3)
0-8	4.08E-3
8-24	1.16E-3
24-96	3.25E-4
96-720	1.23E-5

Control Room
(RWST vent)

Time (hr)	X/Q (sec/m^3)
0-8	9.18E-3
8-24	2.61E-3
24-96	7.31E-4
96-720	2.77E-5

Control Room[(1)]
(LBLOCA)

Time (hr)	X/Q (sec/m^3)
0-8	2.04E-3
8-24	5.80E-4
24-96	1.63E-4
96-720	6.16E-6

[(1)] values are credited for manually selectable, dual intake configuration of the control room air intakes at HNP consistent with the guidance provided in SRP Section 6.4.

4.0 PRESSURE VESSEL FLUENCE EVALUATION

4.1 Introduction

The licensee states that in order to achieve the increased power level, future loadings will include once-burned or even fresh fuel assemblies on peripheral locations, which will increase the neutron leakage. In addition, the new operating conditions will result in higher downcomer temperatures, lower water density, lower thermalization rate, and therefore, higher fast neutron leakage. Finally, the proposed effective full power years (EFPYs) of operation to the end of the current license are 36, i.e., an average load factor of 90% is assumed.

The purpose of this review is to establish the acceptability of the proposed fluence values for 36 EFPYs.

4.2 Evaluation

The fluence calculations are documented in BAW-2355 Supplement 1 (Ref. 17) (attached to the submittal). The calculation methodology was based on BAW-2411PA (Ref. 18), which has been reviewed and approved by the NRC. This review focuses on proper application of the methodology.

The power uprate will be implemented at the beginning of Cycle 11; therefore, well over half of the final fluence value will be accrued after the power uprate. The calculated values include peak locations for the vessel plates and the vessel welds. The values up to the end of Cycle 10 and to 36 EFPYs with many intermediate points are listed in Table 2.3 in Ref. 17. The licensee chose Cycle 18 as the representative equilibrium cycle for the post-uprate loadings. Thus, the Cycle 18 calculation parameters represent the equilibrium cycle for the post-uprate operation. Given that the post-uprate cycles result in higher neutron leakage per EFPY (new or once burned assemblies loaded on the periphery), it is conservative to assume the equilibrium cycle for all of the post-uprate fluence calculations.

There are many parameters that affect neutron leakage and fluence such as fresh or once-burned assemblies at specific locations critical to vessel strength, such as the 0° azimuth (in the eighth symmetry core), which is the peak fluence location. The peak fluence location affects the intermediate shell and the circumferential weld AB. For HNP, the 45° azimuthal location (which corresponds to the minimum fluence location) affects the longitudinal welds. The licensee stated that fresh or once-burned assemblies are not going to be placed in locations different than those analyzed for equilibrium in Cycle 18. This means that the 0° and 45° locations will not be affected by the use of fresh or once-burned assemblies and that the final fluence value will not exceed that at 0° azimuth.

With these assumptions, the licensee determined that the peak fluence on the intermediate shell is 4.59×10^{19} n/cm^2; the peak fluence value for the lower shell is 4.46×10^{19} n/cm^2; and the peak value for the circumferential weld AB is 4.40×10^{19} n/cm^2. The fluence values for the longitudinal welds are in the range of 1.75×10^{19} n/cm^2 to 1.80×10^{19} n/cm^2. Values for the 1/4T and 3/4T locations (needed for the calculation of the pressure-temperature curves and the low temperature overpressure protection limits) are listed in Table 3-14 in Ref. 17. Table 3-14 also lists an evaluation of the RT_{PTS} values for 36 EFPYs for all plates and welds. The licensee

determined that the limiting beltline material is the intermediate shell plate with an RT_{PTS} value of 196.2°F. This RT_{PTS} value describes a vessel with a great deal of margin with respect to 10 CFR 50.61 because the limiting element is 74°F below the screening criteria.

4.3 Summary

In summary, the staff confirmed that the proposed fluence values to the end of the current license (36 EFPYs) were calculated using an approved methodology. The licensee's assumptions are conservative with respect to expected operation of the plant. Therefore, the staff finds the proposed values acceptable for the equilibrium Cycle 18 pattern assumed in the analysis. Any revised loading pattern from the equilibrium Cycle 18 pattern, not bounded by the Cycle 18 analyses, will be reviewed by the staff for the effect on the vessel fluence values.

5.0 COMPONENT AND STRUCTURAL INTEGRITY

5.1 Background

The requested changes in Refs. 1, 2, and 19 revise the surveillance requirements (SRs) for TS 3.4.5, "Steam Generators," and the associated Bases to account for changes associated with replacement of the original SGs and with the revision of specific maximum power level (power uprate). Specifically, the proposed changes would (1) note that the requirements for inservice inspection (ISI) do not apply during the SGR outage (RF10), (2) delete inspection requirements associated with SG tube sleeving and repair limits, (3) revise to delete criteria associated with F* alternative repair criteria (ARC), and (4) allow CP&L to increase the rated core thermal power for the HNP units by 4.5 percent of the amount currently specified in their operating license.

The staff has reviewed the following sections of CP&L's Safety Assessment for PU in respect to materials and chemical engineering:

- Steam Generators
- Chemical and Volume Control System
- Boron Recycle System
- Steam Generator Blowdown System
- Gaseous Waste Processing System
- Liquid Waste Processing System
- Spent Fuel Pool Cooling
- Reactor Vessel

5.2 Steam Generator Issues for SGR

5.2.1 Inservice Inspection (ISI) During the SGR Outage (R10)

SR 4.4.5.0 requires that each SG be demonstrated operable, in part, through the performance of the tube ISI program. The licensee proposed the addition of a note under SR 4.4.5.0, which states that the requirements for ISI do not apply during the SGR outage (R10) since the replacement SGs will be subjected to a preservice inspection prior to installation.

The licensee stated that 100% preservice examination will be performed onsite prior to installation of the SGs. It also stated that the first ISI of the SGs will be performed after 6 effective full power months but within 24 calendar months of initial criticality after the replacement.

In Ref. 19, the licensee stated the pre-service inspection will be performed in accordance with the Electric Power Research Institute PWR SG Examination Guidelines and that the licensee will take no exceptions to the Guidelines. Since a preservice inspection of the replacement SGs will be conducted, the staff finds the proposed change acceptable.

5.2.2 SG Tube Sleeving and Repair Limits

The licensee has proposed changing SR 4.4.5.4., “Acceptance Criteria,” SR 4.4.5.5, “Reports” and Tables 4.4-2 A, B, and C to delete requirements and associated references to (1) repair of the SG tubes by sleeving and (2) plugging limit of tubes previously repaired by sleeving. Further, the licensee proposed the deletion of requirements associated with F* ARC.

The current SRs detail the approved sleeve designs and installation requirements. The licensee states that the referenced requirements are no longer appropriate since the replacement SGs use tubing with a diameter and wall thickness that is different from the original SG tubing. Further, the licensee stated that the replacement SGs use metallurgy and fabrication technology that has proven to be very resistant to corrosion-related degradation and a sleeving design is not expected to be required. Since the current sleeving requirements are not valid for the replacement SGs, the staff finds deletion of these requirements acceptable.

In Ref. 19, on the current plugging limit of 40% in the TS, the licensee stated that an analysis was performed by Westinghouse using the standard Westinghouse methodology per RG 1.121, “Regulatory Guide 1.121 analysis for the Shearon Harris Replacement Steam Generators.” The analysis confirms a defined structural limit of allowable defect depth and confirms the 40% plugging limit, which will remain in the TS for the tubing.

5.2.3 Associated Bases Changes

The staff has reviewed the proposed changes to TS Bases Section 3/4.4.5 and finds them consistent with the changes discussed above. Therefore, the staff finds these changes acceptable.

5.3 Steam Generator Issues for Power Uprate

5.3.1 Steam Generator Tube Degradation

To minimize the effect of the PU on tube degradation, HNP intends to maintain the same T_{hot} (the hot leg temperature) before and after PU. Industry experience has shown that, in general, a high T_{hot} correlates with increased tube degradation. Therefore, limiting T_{hot} to the pre-uprate value should prevent the rate of overall tube degradation from increasing after the power uprate.

CP&L also evaluated other operating parameters affected by the PU. A key change is that the primary-to-secondary differential pressure would increase from about 1435 pounds per square

inch (psi) to 1463 psi. The licensee evaluated the effect to tube degradation and stated that the pressure increase will have a negligible impact on tube degradation.

On the basis of the industry experience and the licensee's SG program for ensuring tube integrity between SG inspections, the staff concludes that the PU will not adversely impact SG tube degradation.

5.3.2 Tube Wear

The licensee performed an assessment regarding the effect of the PU on antivibration bar (AVB) wear. The replacement generators incorporated a major design change using floating fan bars (FFB) instead of AVB bars. Operating experience at units with FFB configuration shows that it significantly minimized wear and wear-related degradation. The licensee's operational assessment demonstrated that the existing allowable operating interval between inspections will remain the same. These operational assessments further demonstrated that performance criteria are satisfied for the inspection interval, after considering uprate conditions. These assessments will be updated to reflect any planned inspections performed prior to implementing the PU. Based on the licensee's assessment, the staff finds that the PU should not significantly affect tube wear.

5.3.3 Additional Surveillance to Monitor Tube Degradation

The licensee stated that before each SG inspection, it assesses degradation mechanisms active in the HNP SGs and in similar SGs throughout the industry. The licensee plans to develop inspection plans that will ensure adequate detection of the degradation mechanism in the affected areas. The staff agrees with the licensee's plans to perform assessments of degradation as part of inspection planning.

5.3.4 Minimum Tube Wall Thickness

The licensee determined the minimum required wall thickness to be 0.022 inch (44 percent of wall thickness) on the basis of a safety margin of three against failure by bursting during normal operations. The licensee stated that the plugging limit of 40-percent throughwall in the current HNP TS satisfies the required minimum wall thickness under the PU conditions. The licensee also stated that the 40-percent throughwall plugging limit applies only to tube degradation detected by a qualified sizing technique. The staff finds that the minimum tube wall thickness will maintain the structural integrity of the tube under PU conditions.

5.4 Reactor Pressure Vessel (RPV) Integrity Issues for Power Uprate

The staff reviewed the information provided by the licensee regarding their assessment of RPV integrity issues associated with the HNP PU and SGR projects. The pertinent information was summarized in Tables 3-1 through 3-16 of report BAW-2355, Supplement 1, "Supplement to the Analysis of Capsule X, Carolina Power and Light Company, Shearon Harris Nuclear Power Plant." The staff confirmed that the only parameter to have changed (based on the staff's review of information previously submitted by the licensee and contained in the staff's Reactor Vessel Integrity Database (RVID)) in these analyses as a result of the PU was the end of license (EOL) neutron fluence value.

For the limiting RPV material (Intermediate Shell B4197-2), the clad-to-base metal interface EOL neutron fluence changed from 4.55 x 10^19 n/cm^2 to 4.59 x 10^19 n/cm^2. This change was confirmed to have an insignificant effect on all RPV integrity analyses (pressure-temperature limits, upper shelf energy drop, pressurized thermal shock) and RPV surveillance program concerns. Therefore, the licensee's existing analyses are acceptable for demonstrating that RPV integrity will be maintained through EOL. Updated information from this submittal will be incorporated into the RVID.

5.5 Review of Miscellaneous Systems

5.5.1 Chemical and Volume Control System

The main role of the CVCS is to manage RCS water inventory, boron concentration and water chemistry. In order to perform these functions, the CVCS must meet the following requirements: (1) the portions of the system constituting reactor pressure boundary must be capable of withstanding the expected RCS conditions, (2) introduction of boron into the RCS must meet the design requirements for reactivity control, and (3) with the exception of RCP seal injection line, the system must be capable of automatically isolating during all events requiring containment isolation. The proposed PU will not affect the CVCS isolation function, but it could have some effect on the integrity of the reactor coolant pressure boundary and on the boration of the RCS.

The licensee performed an analysis of the CVCS performance for SGR/PU. The changes in the following primary plant parameters caused by this modification affect performance of the CVCS: allowable operating range for RCS T_{avg} and thermal design flow. The licensee evaluated the effect of these changes on the performance of CVCS heat exchangers, letdown line, charging system, excess letdown flow, and boric acid system. The performance analysis of the CVCS heat exchangers has indicated that the operating flow rates and temperatures are very close to the current values, and are bound by the heat exchanger design conditions. Their design will be, therefore, adequate for the operating conditions associated with the uprated power. The systems consisting of letdown line, charging system and excess letdown flow were evaluated by verifying performance of the individual components in these systems at uprated power. Adequate performance of all the components have indicated that operability of these systems was not affected by the PU. The effect of PU on the performance of boric acid system was evaluated by verifying that the system has the ability of providing satisfactory flow of boric acid during normal plant operation and during emergency boration. On the basis of the results of these evaluations, the staff finds the licensee's conclusion that SGR/PU will not affect the performance of the CVCS acceptable.

5.5.2 Steam Generator Blowdown System (SGBS)

The SGBS is used in conjunction with the chemical feed and sampling systems to control the composition of the SG shell water within the specified limit. The SGBS also controls the buildup of solids in the SG water. The system has two blowdown connections: to the tube sheet and to the shell side of the SG. The tube sheet connection serves to control the buildup of particulates that enter the SG and accumulate in the tube sheet area. Either the tube sheet connection or the shell connection or both are used to control dissolved solids and maintain proper SG chemistry.

The licensee performed an evaluation of the performance of the SGBS at the uprated power and with the replaced SGs. The evaluation consisted of comparing the components' capacities and design capabilities against the expected changes. It indicated that the continuous allowable flow rates will increase slightly along with a reduction in the maximum allowable SGBS flow per SG. The increase will be insignificant because neither the rate of addition of dissolved solids nor the rate of addition of particulates into the SG will be significantly impacted by the PU. The reduction of the maximum allowable flow rate was required to ensure that the maximum SGBS flow rate is within requirements of the continuous calorimetric program when the plant is operating above 35% power. It consisted of reduction from a current value of 3.5% (~ 300 gpm/SG) of the current maximum steaming rate to ~ 1.7% (~ 200 gpm/SG) of the revised steaming rate for the power uprated case. On the basis of its analysis, the licensee concluded that the PU will not impact the SGBS performance since the increase in continuous allowable normal blowdown rates is negligible and remains bounded by the maximum allowable flow rates. The staff concurs with the licensee's conclusion that the impact of PU on the performance of the SGBS is insignificant.

5.5.3 Waste Processing Systems

5.5.3.1 Gaseous Waste

The function of the gaseous waste processing system (GWPS) is to collect, process and store gases that are contained in contaminated fluids within the plant resulting from plant operation including anticipated operational occurrences. The release of gaseous effluents from the plant should be as low as reasonably achievable and should be in conformance with the appropriate regulatory requirements.

The licensee evaluated the performance of the GWPS for the uprated power conditions. The GWPS in the HNP has a gas decay tank sized for a twin unit station and the current revised waste gas plant inventories are found to be in the range of 1.5 to 3.7 times lower than that associated with a twin unit plant. This provides a significant margin in the GWPS capacity. Also, the reevaluation of doses for the gaseous decay tank rupture accident indicated that the offsite doses for the condition after PU remained unchanged from those reported in the FSAR. On the basis of these findings, the licensee concludes that the existing GWPS design remains adequate for the waste gas inventories associated with the PU. The staff concurs with the licensee's conclusion.

5.5.3.2 Liquid Waste

The function of the liquid waste processing system (LWPS) is to collect, process, store, and control the release of radioactive and potentially radioactive liquids associated with operation, refueling, and maintenance of the plant. The discharge of treated wastes is controlled and monitored to ensure that any discharges are as low as reasonably achievable and they are in conformance with the appropriate regulatory requirements.

The licensee evaluated the performance of the LWPS for the uprated power conditions. Because SGR and PU do not entail equipment modification, there will be no change in the volumes of liquid wastes produced. However, higher activity concentration for some of the isotopes may occur due to the power uprating. This will result in a slight increase in RCS activity and a corresponding increase in waste holdup or floor drain tank content activity.

However, this increase will be within the accuracy of the assumed decontamination factors for the processing equipment used in the calculations. The uprated fission product inventory will remain, therefore, within the design basis capability of the LWPS. On the basis of the results of its evaluation, the licensee concludes that the design of the LWPS remains capable of meeting the design basis functional requirements and performance criteria of the system. The staff concurs with the licensee's conclusion.

5.5.4 Fuel Pool Cooling and Cleanup System

The spent fuel pool cleanup system is part of the fuel pool cooling and cleanup system (FPCCS). Its function is to maintain water quality in the pool by removing fission and corrosion products, which may enter the spent fuel pool water from leaking fuel assemblies as well as the contaminants coming from other sources. The system consists of two cleanup loops and a skimmer loop. Each cleanup loop has two pumps, a single demineralizer, and associate piping, and the skimmer loop consists of skimmer system connections, a pump, and a skimmer filter. The performance of the demineralizers is monitored and the resin is replaced when the ion exchange media is depleted. Also, it is ensured that the temperature of the spent fuel pool water is controlled to prevent damage to the resin.

The amount of fission products released and their radionuclear composition in the pool water will not change appreciably after PU and the existing water cleanup system will be adequate for performing the cleanup function. In order to evaluate operability of the demineralizer at the uprated power, the licensee determined the spent fuel pool water temperatures to which the demineralizer resin will be exposed at different cleanup system operating conditions. The licensee's analysis has indicated that for normal operating conditions spent fuel pool water temperature will not exceed 140°F, which is the upper limit for the demineralizer resin. For emergency operations, the temperature will remain well below the boiling point and will not exceed 150°F. Both these values are within the acceptable limits.

On the basis of the review of the licensee's evaluation, the staff finds that the FPCCS will be adequate for maintaining purity of the spent fuel pool water after PU.

5.6 Summary

Based on its review of the information submitted on the effect of PU conditions, the staff concludes that:

1. The structural integrity of SG tubing is acceptable under the PU conditions.

2. Based on the staff's evaluation of CP&L's proposed HNP TS changes, the proposed changes are acceptable. Although not discussed in the preceding evaluation, each of the proposed changes has bee compared with the Improved Standard TS (ISTS) and has been determined consistent with the ISTS.

6.0 SYSTEMS, STRUCTURES, AND COMPONENTS EVALUATION

6.1 Evaluation for Power Uprate

The staff has reviewed the HNP PU amendment as it relates to the effects of the PU on the structural and pressure boundary integrity of the Nuclear Steam Supply System (NSSS) and the balance-of-plant (BOP) systems. Affected components in these systems included piping, in-line equipment and pipe supports, the RPV, core support structures, reactor vessel internals, control rod drive mechanisms (CRDMs), RCPs, and pressurizer.

6.1.1 Reactor Vessel

The proposed PU requests an increase of approximately 4.5% over the currently licensed level of 2775 MWt in core power. The licensee reported that the power increase will result in changed design parameters given in Table 2-3 of Ref. 20. The licensee, in Table 2-5 of Ref. 20, provided various design basis cases that were developed for use in the PU analysis.

The licensee evaluated the reactor vessel considering the worst load sets of operating parameters and design transients and a new set of LOCA loads, which was identified for the uprated power condition. The regions of the reactor vessel affected by the PU include the outlet and inlet nozzles, the RPV (main closure head flange, studs, and vessel shell), CRDM housing, bottom head to shell juncture, core support pads, and the instrumentation tubes. The licensee evaluated the maximum ranges of stresses and fatigue cumulative usage factors (CUFs) for the critical components at the core power uprated conditions. The evaluation was performed in accordance with the ASME Boiler and Pressure Vessel Code (ASME Code), Section III, 1971 Edition, with addenda through the Winter 1971 to assure compliance with the Code of record. For faulted condition, the components were evaluated in accordance with Appendix F of the ASME Code, Section III, 1974 Edition, since Appendix F was not yet included in the 1971 Edition.

The calculated maximum stresses and the maximum CUFs for the reactor vessel critical locations are provided in Table 5.1.1-1 of Ref. 20. In response to the staff's RAI regarding the allowable stress intensity for reactor vessel closure studs, the licensee, in Ref. 21, stated that the reactor vessel closure stud allowable stress intensity in Table 5.1.1-1 of Ref. 20 contains a typographical error. The correct allowable stress intensity is 110.25 ksi and not 80.1 ksi. The licensee concluded that the vessel closure studs are acceptable for the HNP PU condition. The staff's review of the results provided in Table 5.1.1-1 of Ref. 20 indicates that the maximum stresses are within the allowable limits of the HNP licensing basis, and the CUFs remain below the allowable ASME Code limit of 1.0.

On the basis of its review, the staff concurs with the licensee's conclusion that the current design of the reactor vessel continues to be in compliance with licensing basis codes and standards for the power-uprated conditions.

6.1.2 Reactor Core Support Structures and Vessel Internals

The licensee evaluated the upper and lower internals considering the worst-case set of operating parameters provided in section 2 of Ref. 20. The evaluation was performed in accordance with the original design basis criteria for the HNP reactor internals, which had been previously reviewed by the staff. For the lower core plate reanalysis, the evaluation was performed using Section III, Subsection NG of the ASME Code, 1989 edition with 1990

addenda. The licensee provided calculated margin-of-safety values and CUFs for the PU conditions in Table 5.2-1a and Table 5.2-1b of Ref. 20, respectively. The licensee performed an evaluation to determine the impact of the uprating program on the structural integrity of the upper core plate, and concluded that the upper core plate is structurally adequate for the PU condition. The licensee stated that additional internal components were not evaluated in detail because, based on its experience from similar programs and modifications, the components are less critically affected by power uprating. In addition, HNP uses an upflow configuration in the core barrel/baffle region, which results in very minimal pressure differential across the baffle plate and correspondingly lower baffle-barrel bolt stresses.

Further, the licensee, based on its evaluation, concluded that the PU condition will not adversely impact the response of reactor internal systems and components due to LOCA excitations and flow-induced vibrations, and that the reactor internal components are structurally adequate for the new RCS conditions at HNP.

On the basis of its review, the staff concurs with the licensee's assessment that the reactor internal components at HNP will remain within the allowable limits of the stress and fatigue usage factor for operation at the proposed uprated power conditions.

6.1.3 Control Rod Drive Mechanism

The licensee evaluated the adequacy of the CRDM by reviewing the HNP current Model L-106A-1 CRDM design specifications and stress report to compare the design basis input parameters against the operating conditions at the uprated core power. Based on its evaluation, the licensee stated that the maximum pressure and temperature for the PU condition are bounded by the original operational basis pressure and temperature for the CRDM. The licensee provided a summary of CUFs for the CRDM in Table 5.4-1 of Ref. 20. On the basis of this evaluation, the licensee concluded that the original design basis thermal and structural analyses are bounding for the core PU.

On the basis of its review, the staff concurs with the licensee's conclusion that the current design of the CRDM continues to be in compliance with licensing basis codes and standards for the power uprated conditions.

6.1.4 Reactor Coolant Pumps

The licensee evaluated the HNP RCPs in accordance with Section III, Subsection NB of the ASME Code, 1971 Edition, with Addenda through Summer 1972. The evaluation was performed by comparing the design basis analysis of the Westinghouse Model 93A RCPs with the proposed uprated conditions shown in Table 2-5 of Ref. 20.

The licensee stated that for the core PU condition, the RCS pressure remains unchanged from the original design basis pressure. The RCP inlet temperature, which corresponds to the SG outlet temperature, is slightly lower and thus bounded by the original design basis temperature. The licensee stated that its review of the HNP RCP generic and site-specific pressure boundary summary reports indicated that the design basis fatigue analysis was performed based on the fatigue waiver (i.e., components not requiring analysis for cyclic service) requirements in Section III, Subsection NB-3222.4(d) of the ASME Code. In response to the staff’s RAI regarding the fatigue evaluation of the RCP, the licensee, in Ref. 21, stated that it reviewed and

compared the normal and upset condition transients with the transients related to the uprating program. For cases in which the temperature and/or pressure changes are not bounded, the licensee reviewed the generic pressure boundary stress reports. The licensee stated that only a significant fluctuation is of interest in fatigue evaluation since the generic reports use the ASME Code fatigue waiver. The licensee, based on its review of the generic reports, stated that none of the temperature and/or pressure changes causes a non-significant pressure or thermal transient to become a significant transient. The licensee concluded that the fatigue waiver evaluation for the current HNP licensing basis is bounded by the power uprating condition.

On the basis of its review, the staff concurs with the licensee's conclusion that the current Model 93A RCPs, when operating at the proposed uprated power conditions, will remain in compliance with the requirements of the codes and standards under which HNP was originally licensed.

6.1.5 Pressurizer

The licensee evaluated the adequacy of the pressurizer and components including the pressurizer spray nozzle, safety and relief nozzle, upper head and shell, manway pads and bolts, instrument nozzle, support lug, surge nozzle, lower head/heater well, immersion heater and valve support bracket for operation at the uprated conditions. The licensee reviewed and compared the input parameters associated with the HNP power uprating program to the design inputs considered in the current pressurizer stress report. In cases where revised input parameters were not bounded, the licensee performed additional structural evaluation. The licensee used the scaling factors to assess the impact of the changes in the parameters such as the system transients, temperatures, and pressures. The evaluation was performed in accordance with the requirements of the ASME Code, Section III, 1971 Edition, through Summer 1972 addenda. The licensee calculated revised stresses and CUFs and confirmed that the pressurizer stresses and the CUFs remain within the Code-allowable limits for the PU condition. The licensee provided the CUFs for the uprating condition in Table 5.8-1 of Ref. 20.

The licensee indicated that the design basis loads considered in the pressurizer structural analysis remain conservative for the HNP PU condition. The maximum calculated stresses at the critical locations are unchanged except for the surge line nozzle. The maximum stress intensity at the surge line nozzle was recalculated and was found to be within the Code-allowable limit.

The performance of the PSVs and the PORVs are dependent on the pressurizer operating pressure and temperature. The licensee stated that the total capacity of the installed PORVs is higher than the required capacity at the uprated power condition, and the total capacity of PSVs at set pressure plus 3 percent accumulation is higher than the calculated maximum required capacity at the uprated power condition.

On the basis of the above review, the staff concurs with the licensee's conclusion that the pressurizer and components remain adequate for plant operation at the proposed uprated core power.

6.1.6 NSSS Piping and Pipe Supports

The licensee evaluated the NSSS piping and supports by considering the effect of the design parameters (section 2 of Ref. 20) for the power uprating program including the revised weight and center of gravity of the replacement steam generators (RSGs), transients, seismic effects, and the LOCA dynamic loads. The licensee reanalyzed the reactor coolant loop (RCL) piping, primary equipment nozzles, primary equipment supports, and the class 1 auxiliary line piping that included the pressurizer surge line piping, accumulator line piping in loops 1, 2, and 3, and the RHR piping in loops 1 and 2. The methods, criteria, and requirements used in the existing design basis analysis for HNP were used for the PU evaluation.

The original structural design basis of HNP RCL piping and supports required consideration of dynamic effects resulting from postulated guillotine breaks in the primary loop piping. In 1985, NRC approved the application of leak-before-break (LBB) methodology for HNP. The licensee performed the LBB evaluation of HNP primary loop piping to justify the elimination of RCS primary loop pipe breaks with the new replacement generators at the uprated power of 2912.4 MWt. In the application of the flaw stability criteria, the licensee considered both global and local stability for a postulated throughwall circumferential flaw. The licensee's LBB acceptance criteria are based on SRP section 3.6.3. Based on its evaluation, the licensee concluded that the dynamic effects of the RCS primary loop pipe breaks need not be considered in the structural design basis of the HNP power uprating program.

The licensee provided its evaluation of the RCS system piping and supports and systems connecting to the RCS system in Table 5.5.1-2 and Table 5.5.1-3 of Ref. 20. The results indicate that in all cases, the calculated stresses for the RCS system piping and supports and systems connecting to the RCS system are within the HNP licensing basis allowable stresses and that the CUFs are less than 1.0. The licensee, in Table 5.5.3-1 of Ref. 20, provided results of its evaluation of class 1 auxiliary lines piping and concluded that the calculated stress is within the HNP licensing basis allowable stress and the CUFs are less than 1.0.

On the basis of the above review, the staff concurs with the licensee's conclusion that the NSSS piping and supports, the primary equipment nozzles, the primary equipment supports, and the class 1 auxiliary lines piping meet the requirements of the design bases criteria, as defined in the FSAR, and are acceptable for the PU.

6.1.7 BOP Systems and Motor-Operated Valves (MOVs)

The licensee evaluated the adequacy of the BOP systems including piping, and HVAC systems based on comparison of the existing design bases parameters, and/or the original design capacities with the core PU conditions. The BOP piping systems evaluated in Ref. 22 for the PU are: main steam, extraction steam, and auxiliary steam system, condensate and feedwater system, circulating water system, CCWS, normal and emergency service water systems, AFW system, CVCS, SI system, and SGBD system.

The licensee indicated that the current design basis analyses are based on input system parameters such as pressure, temperature, and flow rate, which have not changed significantly for the PU condition. The licensee evaluated revised process conditions for BOP systems under PU and concluded that the revised process conditions remain within the system design limits. For instance, the current design basis operating pressure and temperature for the main steam system increase from 883 psia and 529.7°F to 1011 psia and 545.9°F, respectively, for the PU operating condition. The licensee stated that the main steam system is designed for a

pressure of 1200 psia and temperature of 600°F. These values bound the main steam system operating pressure and temperature at uprate operating conditions. The licensee concluded that the main steam system lines are adequately sized for the uprate conditions and they are within existing design limits in accordance with the FSAR. The licensee indicated that the criteria to size the main steam safety valve (MSSV) is to relieve 105% of maximum calculated steam flow at an accumulation not exceeding 110% of main steam system design pressure. The licensee committed to demonstrate that each MSSV is operable with lift setting as specified in FSAR Table 10.3.1-1. The licensee concluded that the MSSVs are adequately designed for the PU. On the basis of its review, the staff finds the safety and relief valves will continue to perform their function at the PU condition. For the HVAC systems, the licensee stated that the changes to current operation heat loads are negligible for the PU and does not adversely affect the existing design of the HVAC systems. On the basis of its analysis, the licensee concluded that the BOP piping, pipe supports and equipment nozzles, and HVAC systems remain acceptable and continue to satisfy the design basis requirements for the PU.

In response to the staff's RAI regarding the capability of safety-related MOVs, the licensee, in Ref. 21, stated that the safety-related MOVs are capable of performing their intended function(s) following the power uprate. The licensee stated that HNP MOV calculations are based on the design differential pressure for a specific valve in the MOV program. Typically it used conservative bounding values for fluid density and the maximum differential pressure which occurs at no flow conditions (i.e., when a valve reaches the closed position or is opening from the closed position). The licensee confirmed this determination by verifying that changes in system operating temperature and pressure were bounded by the requirements of the associated equipment specification. On the basis of its review, the staff concurs with the licensee's conclusion that the PU will have no adverse effects on the safety-related valves and the MOVs program.

The licensee also evaluated its response relating to the GL 96-06 program regarding the overpressurization of isolated piping segments. In Ref. 21, the licensee stated that for the two originally affected penetrations, the piping temperatures used in the existing evaluation for GL 96-06 remain bounding for the post-uprate condition. On the basis of its review of the licensee's evaluation, the staff concurs with the licensee's conclusion that the PU has no significant impact on the design basis for components within affected BOP systems.

6.2 Evaluation for SGR

The proposed changes to the TSs are required in part as a result of the physical differences between the currently installed Model D4 SGs and the Model Delta 75 RSGs. The Model Delta 75 RSGs have thermally treated alloy 690 tube material that has been proven through laboratory testing and operational experience to provide increased corrosion resistance compared to the Inconel 600 tube material in the Model D4 SG. The replacement of the currently installed Model D4 SGs with the Model Delta 75 replacement SGs will avoid corrosion and cracking of SG tubes similar to that experienced at other plants with similar model D SGs.

The licensee has performed analyses and evaluations of the NSSS and BOP structures, systems, and components (SSCs) to support HNP operations with the RSGs at the current licensed core power of 2775 MWt and also, where possible, at an uprated core power level of 2900 MWt. The purpose of these analyses and evaluations is to demonstrate that the applicable acceptance criteria continue to be met.

CP&L has drawn upon the experience of Westinghouse Electric Company in support of other SG replacement projects at other nuclear power plants. In particular, the license amendment applications for the Joseph M. Farley Nuclear Plant and the V. C. Summer Nuclear Station were used as benchmark amendment applications for the HNP SGR. CP&L's technical bases for the proposed changes are provided in Enclosures 6 and 7 of Ref. 1. Enclosure 6 contains the NSSS Licensing Report and Enclosure 7 is the BOP Licensing Report.

By letter dated April 20, 2001, NRC requested additional information to support staff review of the proposed license amendment requests. CP&L's letter dated June 4, 2001 (Ref. 23) provided the licensee's response to the staff's RAI. On August 23, 2001, a conference call was held to provide clarification to CP&L on the RAI. In Ref. 24, the licensee provided additional information.

The SGR/Uprate submittal for HNP includes analyses and evaluations of selected NSSS design parameters and the design of BOP SSCs and their functional capabilities. The SGR/Uprate program included analysis of LOCA and non-LOCA transients, and evaluations of the thermal hydraulic, nuclear, and mechanical fuel design aspect of the NSSS and BOP SSCs. The results of these analyses and evaluations are described and summarized in the NSSS Licensing Report (Enclosure 6 of Ref. 1) and BOP Licensing Report (Enclosure 7 of Ref. 1).

The licensee stated in the NSSS Licensing Report that evaluations were performed to assess the impact of the SGR/Uprating conditions on all the NSSS components, and the purpose of the evaluations is to confirm that the NSSS components continue to satisfy the applicable codes, standards, and RGs under the revised conditions. The following component areas were assessed: reactor vessel integrity, reactor internals, fuel assemblies (structural), CRDM (structural), RCL piping and supports and leak-before-break, reactor coolant pump and motor, SG (structural, thermal/hydraulic and flow-induced vibration), pressurizer (structural), and NSSS auxiliary equipment evaluation.

The licensee performed the evaluations for the HNP RCL piping and support system to consider the impact of the design parameters for the SGR/Uprating program, including the revised weight and center of gravity (CG) of the RSGs. The licensee stated that the analysis results show that the primary stresses are below the allowable limits established in the ASME Code, Section III (NB), through Winter of 1979 Addenda, under the design, upset, and faulted conditions. The RCL piping secondary stresses and fatigue usage factors are in conformance with the requirements of the Code for the fatigue damage evaluation performed under normal, upset, and test conditions. The primary equipment nozzle loads are also acceptable. Therefore, the RCL piping system is adequate for applicable design loading conditions. The as-built primary equipment support system meets all specified design conditions, as defined by the ASME Code, Section III (NF), through Winter of 1974 Addenda, the original Code of record for the HNP primary equipment supports. The licensee concluded that the RCL system will maintain its structural integrity and meet all safety-related design requirements. The staff finds the licensee's conclusion acceptable.

As a result of the revised weight and CG of the RSGs, the revised design transients for the SGR/Uprating program, the revised NSSS design parameters for the SGR/Uprating program, and the revised Class 1 Auxiliary Line pipe support stiffness values, the existing seismic displacements at some large bore (larger than 6 inches) Class 1 Auxiliary Line connections to

RCL have changed and new seismic analysis for these lines was performed for the SGR. The licensee concluded that the Class 1 auxiliary piping, as stipulated in the design specification, is calculated to maintain its structural integrity and meet its safety-related requirements. The staff finds this conclusion acceptable.

The licensee stated that the HNP Model Delta 75 RSGs were analyzed at uprated power conditions in the areas of structural acceptability, thermal-hydraulic performance, and flow-induced vibration and wear. The appropriate NSSS parameters were used for the SG structural integrity evaluation. The evaluations were performed to the requirements of ASME Code Section III, 1971 edition, including 1972 Summer Addendum.

Some critical primary side components and secondary side components affected by the uprate were evaluated for structural adequacy. The licensee concluded that results of analyses performed on the HNP Model Delta 75 SGs show that ASME Code Section III is satisfied at uprated power conditions with up to 10-percent SG tube plugging, with the exception of the secondary manway bolts and 4-inch inspection port bolts. For these bolts, it was found that the maximum fatigue usage exceeds the limit of 1.0. Therefore, these bolts will be replaced at a convenient time as part of normal maintenance activities, prior to the bolts reaching the stated fatigue life of 27 and 30 years of service for the manway and 4-inch inspection port bolts, respectively. The staff finds the licensee's evaluations acceptable.

With respect to flow-induced vibration and wear, the licensee stated that the only significant change identified as a result of SGR/Uprating is the reduced feedwater temperature, which can be maintained at an upper temperature at full power of 375°F rather than the 440°F as specified in the Model Delta 75 design specifications. An evaluation was performed and the results led the licensee to conclude that the flow-induced vibration and wear for the 375°F feedwater case is acceptable since the previous analysis for the 440°F feedwater case envelopes the 375°F feedwater case. The licensee further concluded that the previous structural analysis of the tubes remains bounding relative to the SGR/Uprating since the input parameters related to flow-induced vibration are unchanged. The staff finds the licensee's evaluation acceptable.

In the BOP Licensing Report, the licensee describes the evaluations of the design and licensing aspects of BOP SSCs, functions, and analyses not included in the NSSS Licensing Report, with consideration given to the proposed SGR. Most of the BOP systems were evaluated to determine their performance capabilities for plant operation with the Model Delta 75 RSGs at the uprated NSSS power level of 2912.4 MWt. In particular, those systems having configuration changes and revised process conditions, such as the Condensate and Feedwater Systems, the AFW System, and the SGB System, were evaluated to ensure that, following the SGR/PU, these systems remain capable of performing their required functions. The licensee concluded that the BOP analyses and evaluations demonstrate that applicable acceptance criteria for BOP SSCs are met. The staff finds this conclusion acceptable.

In the April 20, 2001, RAI No. 4, the staff requested the licensee to demonstrate the integrity of the SG tubes in the HNP Model Delta 75 RSGs for the effects of thermal transients arising from postulated large-bore RCS pipe breaks LOCA condition during the PU. In its responses provided in Ref. 24, the licensee stated that the thermal effects for the faulted thermal transients (LBLOCA, MSLB, etc.) on the primary side of the RSG components have been considered as required by the ASME Code. Faulted secondary stress effects are not required

to be considered in the Code stress evaluation, but are required to be investigated for the possibility of brittle fracture. The licensee further stated that non-ferrous materials such as Inconel and stainless steel normally exhibit ductile behavior even at relatively low operating temperatures. The HNP Delta-75 RSG tube material is thermally treated Ni-Cr-Fe Alloy 690. Testing indicates that the tube material will not fail in a brittle fashion in the temperature range of concern. Therefore, brittle fracture of the HNP Delta-75 tubes is not a concern and a fracture mechanics evaluation is not required. The staff's question whether the thermal tube locking conditions could result in loading sufficient to cause a circumferential crack to open and result in secondary-to-primary in-leakage following a LOCA, even though the ASME Code does not require thermal loadings to be addressed during faulted conditions is beyond the plant design basis, and the staff agreed to pursue it in the context of the criteria for tube plugging on a generic basis with industry.

6.3 Summary

On the basis of its review in Section 6.1, the staff concurs with the evaluations performed by the licensee for the NSSS and BOP piping, components, and supports, the reactor vessel and internal components, the CRDMs, RCPs, and the pressurizer. The staff finds the licensee's evaluation to be bounded by the licensing Code of record and the original design basis, and therefore, concludes that the foregoing components are acceptable for HNP uprate operations at the proposed core power level of 2900 MWt.

On the basis of its review in Section 6.2, the staff concludes the licensee’s analyses and evaluations to support replacing existing Westinghouse Model D4 SGs with the Model Delta 75 RSGs are reasonable, and therefore, acceptable.

7.0 BALANCE OF PLANT SYSTEMS

7.1 Condensate and Feedwater Systems

The licensee evaluated the condensate and feedwater systems to determine their performance capabilities for plant operations at the proposed SGR/PU level. Also, the licensee re-analyzed these systems with respect to issues such as water hammer and system pressure transients. The licensee concluded that these systems satisfy their design bases for plant operations at the proposed SGR/PU level. Since these systems do not perform any safety-related function, we have not reviewed the impact of plant SGR/PU operations on the design and performance of these systems.

7.2 Steam Systems

7.2.1 Main Steam System

The licensee evaluated the effects resulting from plant SGR/PU operations on the main steam system including the MSIVs, MSPORVs, main steam isolation bypass valves (MSBVs), and MSSVs. The licensee stated that main steam design conditions of 1200 psig (psi, gauge) and 600^0F remain unchanged, and bound all predicted SGR/PU operating conditions for the system and components. Therefore, plant SGR/PU operations will have no impact on the main steam system and its associated components.

Based on the review of the licensee's rationale and evaluation, and the experience gained from our review of PU applications for similar PWR plants, the staff concurs with the licensee that plant operations at the proposed SGR/PU level will have no impact on the main steam system.

7.2.2 Steam Dump System

The steam dump system creates an artificial steam load by dumping steam from ahead of the turbine stop valves to the main condenser. It does this by releasing steam to the atmosphere and the condenser, depending upon the size of the load rejection. The licensee evaluated the steam dump system for plant SGR/PU operations and stated that all the steam dump system SGR/PU operating conditions remain bounded by the existing design conditions. Since this system does not perform any safety-related function, a review of the impact of plant SGR/PU operations on the design and performance of this system was not done.

7.2.3 Extraction Steam System

The extraction steam system is designed to provide steam at various pressures and temperatures to preheat condensate and feedwater as it flows from the main condensers to the SGs. Since the extraction steam system does not perform any safety-related function, the staff did not review the impact of plant SGR/PU operations on the extraction steam system.

7.2.4 Auxiliary Steam System

The auxiliary steam system, which is designed to supply low-pressure saturated steam throughout the station for auxiliary services, does not perform any safety-related function. A review of the impact of plant SGR/PU operations on the design and performance of the auxiliary steam system was not done.

7.2.5 Turbine-Generator Evaluations

The licensee performed evaluations on turbine operations with respect to the turbine overspeed protection and the design acceptance criteria to verify the mechanical integrity under the conditions imposed by plant SGR/PU operations. Results of the evaluations showed that the ability of the turbine overspeed protection system is not affected by the SGR/PU operations. There would be no increase in the probability of turbine overspeed nor associated turbine missile production due to plant SGR/PU operations. Therefore, the licensee concluded that the turbine could continue to be operated safely at the proposed SGR/PU level.

Based on our review of the licensee's evaluation, and the experience gained from our review of PU applications for similar PWR plants, the staff finds that operations of the turbine at the proposed SGR/PU level is acceptable.

7.2.6 Circulating Water System

The circulating water system is designed to remove the heat rejected to the condenser by turbine exhaust and other exhausts over the full range of operating loads, thereby maintaining adequately low condenser pressure. The licensee stated that performance of this system was

evaluated for SGR/PU operations and it was determined that the system is adequate for the proposed SGR/PU operations. Since the circulating water system does not perform any safety function, the staff has not reviewed the impact of plant SGR/PU operations on the designs and performances of this system.

7.2.7 Component Cooling Water System (CCWS)

The CCWS is a closed loop system that serves as an intermediate barrier between the essential (non-radioactive) service water system and systems/components that contain radioactive or potentially radioactive fluids. It provides cooling water to various safety and non-safety systems during all plant operating modes. The CCWS heat loads resulting from plant operations at the proposed SGR/PU level will increase slightly. The increased heat loads are primarily due to the increased spent fuel pool (SFP) heat load, RHR system heat load during plant cool down and RHR heat load during post-LOCA recirculation mode. The licensee performed evaluations (conservatively assuming higher values for CCW supply temperatures) of the effects of the increases in heat loads, including a combined heat load of 1.0×10^6 Btu/hr from the SFPs[1] C and D. The licensee concluded that the existing CCWS pump impellers[2] are required to be changed to provide more system flow for cooling to accommodate the increased heat loads.

Based on our review and evaluation, and the experience gained from our review of PU applications for similar PWR plants, we conclude that the CCWS, with the pump impeller changes, is acceptable for HNP operations at the proposed SGR/PU level.

7.2.8 Service Water Systems

The service water system (SWS) consists of two interconnected systems: the essential service water system and the normal service water system.

7.2.8.1 Essential Service Water System (ESWS)

The ESWS is designed to supply cooling water to various safety-related systems and other essential equipment during normal plant operations, a station blackout event, and/or a LOCA or MSLB accident. It circulates water from the ultimate heat sink (UHS) through safety-related systems/components required for safe shutdown of the reactor, a station blackout (SBO) event, and/or a LOCA or MSLB accident, and returns it to the UHS. The licensee performed evaluations and stated that for plant operations at the proposed SGR/UP level, the ESWS flow rates are required to be raised from 8,500 gpm to 10,000 gpm during normal operation and from 8,000 gpm to 8,500 gpm during accident conditions. However, the new required ESWS

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[1] In a separate amendment request (dated December 23, 1998), the licensee proposed to store old spent fuel assemblies (SFAs) in SFPs C and D. However, the maximum combined decay heat load in these SFPs is limited to 1.0×10^6 Btu/hr. The staff's approval of the request was supported by the SE dated December 21, 2000.

[2] The CCWS pumps with the existing impellers are rated for 8,050 gpm at a pump head of 211 ft. The licensee stated that the existing impellers of the CCWS pumps will be replaced with new impellers rated for 10,500 gpm at a pump head of 237 ft.

flow rates are less than the ESWS design flow rate of 12,000 gpm. Therefore, the ESWS, as designed, will supply sufficient cooling water to remove the additional heat loads resulting from plant SGR/PU operations.

Based on our review and evaluation of the licensee's rationale, and the experience gained from our review of PU applications for similar PWR plants, the staff concludes that plant operations with the proposed SGR/PU have insignificant impact on the ESWS.

7.2.8.2 Normal Service Water System (NSWS)

The NSWS is designed to supply cooling water to various non-safety-related components and heat exchangers associated with the power conversion system, reactor operation, and miscellaneous building services during normal plant operation including start-up, normal shutdown, and hot standby. The NSWS circulates water from the cooling tower basin through the non-safety-related components and heat exchangers and back to the cooling tower. It serves no safety-related functions. The licensee performed evaluations of the effects of these increases in heat loads on the NSWS and stated that the NSWS has the capacity to accommodate the additional heat loads.

Since the NSWS does not perform any safety function and its failure will not affect the performance of any safety-related system or component, the staff has not reviewed the impact of plant SGR/PU operations on the designs and performances of this system.

7.2.8.3 Ultimate Heat Sink

The UHS for HNP is composed of mechanical-draft cooling towers and reservoirs (one auxiliary reservoir and one main reservoir). During plant operation, both essential and non-essential cooling loads are rejected to the cooling towers. Following a LOCA, all non-essential cooling loads (such as the turbine building loads) will be isolated and the essential service water supply intake is switched from the cooling towers to the auxiliary reservoir via the emergency service water intake channel. The main reservoir provides makeup water for the cooling towers and serves as a backup supply of water for the auxiliary reservoir. In addition, the UHS provides (via the ESWS) the safety-related source of AFW when the CST is not available. The licensee performed evaluations and concluded that the UHS will provide sufficient cooling water under a DBA for plant operations at the proposed SGR/PU level.

Based on our review of the licensee's evaluation, and the experience gained from our review of PU applications for similar PWR plants, we conclude that plant operations at the proposed SGR/PU level will have an insignificant or no impact on the UHS.

7.2.9 Auxiliary Feedwater System/Condensate Storage Tank

The licensee performed evaluations of the effects of plant operations at the proposed SGR/PU on the AFW system/CST. The licensee determined that the AFW system components have sufficient margin to provide the required flows to cope with various transients, accidents, or an SBO event for plant operations at the proposed SGR/PU. The CST has a capacity of 270,000 gallons with a usable volume of 238,000 gallons. In Ref. 25, the licensee stated that for the cooldown operation and a 4-hour coping duration during an SBO event, the minimum usable CST volume required was determined to be approximately 117,013 gallons.

Based on the review of the licensee's evaluation, and the experience gained from the review of PU applications for similar PWR plants, the staff concludes that the AFW/CST are acceptable for the proposed plant SGR/PU operations.

7.2.10 Fuel Pool Cooling

HNP has four separate SFPs designated as A, B, C, and D. These SFPs are interconnected by transfer canals and separated by gates. In addition to the SFAs discharged from HNP, each SFP is used to store SFAs from the Robinson (PWR) and Brunswick (BWR) plants. However, SFP C and D are designated to only store old SFAs that have been cooled for at least 5 years with a total heat load limited to 1.0×10^6 Btu/hr.

The FPCCS at HNP is comprised of three subsystems: two redundant cooling loops, two cleanup loops, and a skimmer loop. Each SFP cooling loop, which consists of a cooling pump, a heat exchanger, and a strainer, is capable of removing 100% of the heat load from the SFAs stored in all SFPs. Currently, there are administrative controls and procedures in place to ensure that the minimum cooling time (SFAs "in-reactor" hold time) required prior to transferring irradiated fuel from the core to the SFPs and adequate cooling capability are provided to maintain the pool at less than or equal to 137°F during planned core off-load outages. As a result of plant operations at the proposed SGR/PU level, the decay heat load for any specific fuel discharge scenario will increase. The licensee stated that this SFP water temperature limit of 137^{0}F will be raised to 140^{0}F with a single active failure of the SFP cooling pumps for SGR/PU operations.

Maintaining the SFP temperature limit of 140^{0}F at HNP is based on two primary parameters. The first is the CCWS supply water temperature, since the heat removal capability of the SFP cooling loops is a function of CCWS temperature. The second is the core in-reactor hold time following reactor shutdown, since this determines the heat load in the SFP. In Ref. 25, the licensee stated that prior to planned refueling outages, administrative controls and procedures require analyses to be performed with the actual CCWS supply water temperature that exists at the time of the planned refueling outages for determining the required core in-reactor hold time following reactor shutdown to maintain the SFP water below the temperature limit of 140°F.

Also, HNP has a monitor system for monitoring the SFP levels, temperatures, and pump status. The monitor system alarms in the control room when the SFP water temperature reaches the temperature setpoint of 105^{0}F. Annunciator response instruction provides direction for the operator to take appropriate corrective actions. This will provide additional assurance that the SFP temperature limit of 140^{0}F is not exceeded.

Based on the review of the licensee's rationale, the experience gained from our review of PU applications for similar PWR plants, and the fact that the plant has administrative controls and operating procedures in place to ensure that adequate cooling capability is provided for all SFP cooling scenarios, the staff finds that the design and operation of the SFP cooling systems at HNP for the SGR/PU conditions meet the guidance described in SRP Section 9.1.3 for SFP cooling and cleanup systems, and therefore, concludes that the SFP cooling system at HNP is acceptable for the proposed plant SGR/PU operations.

7.2.11 Containment Spray System

The function of the CSS is to remove the heat and fission products that may be released into the containment atmosphere following a LOCA or MSLB by spraying borated sodium hydroxide solution into the containment.

The licensee indicated that the CSS was evaluated to ensure that following the SGR/PU the system remains capable of performing its required functions in accordance with the FSAR. The evaluation showed that the SGR/PU does not change the CSS and its functions described in the FSAR. Revised process conditions are within the existing design bases of the system and its components. The CSS meets all the functional requirements at SGR/PU conditions. Therefore, the existing CSS design condition remains acceptable and no system design modifications are required.

Based on our review of the licensee's rationale and evaluation, and the experience gained from our review of PU applications for similar PWR plants, we conclude that the CSS is acceptable for HNP operations at the proposed SGR/PU level.

7.2.12 Heating, Ventilation and Air Conditioning (HVAC) Systems

The licensee evaluated the following systems to ensure that margin and capability exist to operate satisfactorily to support the plant thermal PU to 2912.4 MWt.

- Containment Ventilation and Cooling Systems
- Reactor Auxiliary Building (RAB) HVAC System
- Fuel Handling Building (FHB) HVAC System

The licensee stated that the SGR/PU does not change containment ventilation and cooling systems design functions. The licensee indicated that an evaluation shows that the SGR/PU does not impact the existing design of the containment ventilation and cooling systems, and that the system has adequate cooling capacity to maintain the space design conditions.

In addition, the licensee stated that the HVAC systems for the RAB and FHB have been evaluated to determine their performance capabilities for plant operation with the Model Delta 75 RSGs at the uprated NSSS power level of 2912.4 MWt.

The licensee stated that the evaluation shows that the SGR/PU does not impact the existing design of the RAB HVAC System, and that the system will continue to satisfy the existing requirement in accordance with the FSAR. The licensee further stated that the SGR/PU does not adversely affect the existing design of the FHB HVAC System. In accordance with the licensee's submittal, the results obtained with the Model Delta 75 RSGs at the uprated NSSS power level of 2912.4 for the FHB and RAB HVAC Systems remain bound by the current power.

Based on a review and assessment of the information provided in the licensee's submittal, we agree with the licensee's conclusions that plant operations at the proposed uprated NSSS power level of 2912.4 MWt will have an insignificant impact on Containment Ventilation and Cooling Systems, and FHB and RAB HVAC systems.

7.2.13 Essential and Non-Essential Chilled Water Systems

The essential services chilled water system (ESCWS) provides chilled water to the RAB HVAC systems and FHB SFP pump room ventilation system. The non-essential services chilled water system (NESCWS) provides chilled water to the FHB SFPs and operating floor HVAC, and waste processing building HVAC. The cooling loads of these HVAC systems are not power dependent. The licensee-performed evaluations concluded that SGR/PU has no adverse effect on the design functions of the ESCWS and NESCWS.

Based on our review and the experience gained from our review of PU applications for similar PWR plants, we find that plant operations at the proposed SGR/PU level do not change the design aspects and operations of the HVAC systems. Therefore, we concur with the licensee that plant operations at the proposed SGR/PU level will have no impact on the ESCWS and NESCWS.

7.2.14 Emergency Diesel Generators

The EDGs and their associated systems are not power dependent. The licensee performed evaluations and stated that the SGR/PU does not change existing EDG design functions. The EDGs remain capable of satisfying regulatory commitments in accordance with the existing FSAR.

Based on our review and the experience gained from our review of PU applications for similar PWR plants, we agree with the licensee that plant operations at the proposed SGR/PU level has insignificant or no impact on the EDGs and their associated systems.

7.2.15 Station Blackout

The licensee evaluated the effects of the proposed plant SGR/PU operations on an SBO event using the guidance described in RG 1.155, “Station Blackout,” and the Nuclear Management and Resources Council, Inc. (NUMARC) 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors.” The licensee stated that the temperature heat-up in the dominant areas of concern and equipment/systems needed to mitigate the SBO event are not affected by the proposed plant SGR/PU operations. No changes to the systems and equipment used to cope with an SBO event are required.

Based on our review of the licensee's rationale and the experience gained from our review of PU applications for similar PWR plants, the staff finds that the impact on the coping with an SBO event resulting from plant operations at the proposed SGR/PU level is insignificant.

7.2.16 Radioactive Waste Management

7.2.16.1 Solid and Liquid Waste Processing Systems

The solid and liquid radwaste activity is influenced by the reactor coolant activity, which is a function of the reactor core power. However, the existing design of the solid and liquid radwaste processing systems is based on a core power level of 2900 MWt, and plant operations at the proposed SGR/PU level do not change the design aspects and operations of the radwaste processing systems. Therefore, the licensee stated that plant operations at the proposed SGR/PU have no impact on the solid and liquid waste processing systems.

Based on our review of the licensee's rationale, and the experience gained from our review of PU applications for similar PWR plants, we agree with the licensee that plant operations at the proposed SGR/PU level have no impact on the solid and liquid waste processing systems.

7.2.16.2 Gaseous Waste Processing System

The GWPS is designed to collect, process, and store gaseous wastes, ensuring that the release of the gaseous effluents from the plant and expected offsite doses are as low as reasonably achievable, and that they are in conformance with the requirements specified in 10 CFR 20 and 10 CFR 50.

The licensee indicated that the GWPS was evaluated to ensure that following the SGR/PU the system remains capable of performing its required functions in accordance with the existing licensing bases specified in the FSAR. The evaluation showed that the SGR/PU does not change GWPS design functions. There are no configuration changes associated with the GWPS under SGR/PU conditions, and changes to GWPS process conditions are minor and within the capabilities of the existing design.

Based on our review of the licensee's rationale and evaluation, and the experience gained from our review of PU applications for similar PWR plants, the staff agrees with the licensee that plant operations at the proposed uprated power level will have an insignificant impact on the GWPS.

7.2.17 Equipment Qualification of Non-Metallic Materials

The licensee performed evaluations and stated that review of the process conditions for the proposed SGR/PU operation did not reveal any process temperature change greater than 10% from the actual temperature. Because of the large difference between the pre-SGR/PU process temperature and the actual temperature-withstanding capability of the non-metallic materials, the increase in the post-SGR/PU process temperature will have no adverse impact on the equipment qualification of non-metallic materials.

Based on our review of the licensee's rationale and the experience gained from the review of PU applications for similar PWR plants, the staff agrees with the licensee that plant operations at the proposed SGR/PU level have no impact on the equipment qualification of non-metallic materials.

7.2.18 Containment and Subcompartment Analyses

7.2.18.1 Containment Integrity Analysis

The licensee performed containment integrity analyses at the SGR/PU conditions to ensure that the maximum pressure inside the containment will remain below the containment design pressure of 45 psig if a design bases LOCA or MSLB inside containment should occur during plant operation. The analyses also established the pressure and temperature conditions for environmental qualification and operation of safety-related equipment located inside the containment. The LOCA peak pressure is also used as a basis for the containment leak rate test pressure to ensure that dose limits will be met in the event of a release of radioactive material to containment.

The licensee indicated that the containment functional analyses included the assumption of the most limiting single active failure and the availability or unavailability of offsite power, depending on which resulted in the highest containment temperature and pressure. Bounding initial temperatures and pressures for analyses were selected to envelope the limiting conditions for operation. The containment integrity analysis and assumptions are presented in enclosures 6 and 7 of the submittal.

7.2.18.2 Containment Integrity Analyses - LOCA

The licensee performed analyses to determine the containment pressure and temperature response during postulated LOCAs using mass and energy releases that incorporate revised design parameters corresponding to core rated power of 2900 MWt plus a 2% allowance for calorimetric error. As in the current HNP FSAR, the postulated LOCA analyses were performed for the double-ended hot leg guillotine (DEHLG) break and the double-ended pump suction leg guillotine (DEPSLG) break of the reactor coolant pipe. It has been determined that the DEHLG break results in the most limiting pressure and temperature during the initial blowdown phase and that the DEPSLG break yields the highest energy flow rates during the long-term post-blowdown period.

The licensee stated that the mass and energy releases in the containment were calculated for PU using Westinghouse TR WCAP-10325-P-A. The uprate analyses used the American Nuclear Society's 1979 ANS 5.1 decay heat model with 2 sigma uncertainty factor. The current analyses also used Westinghouse TR WCAP-10325-P-A. We find the use of the above decay heat model with 2 sigma uncertainty and Westinghouse TR WCAP-10325-P-A for LOCA mass and energy release calculations acceptable.

The mass and energy releases calculated by the above analyses were utilized for uprated containment pressure and temperature response analyses using the CONTEMPT-LT/26 computer code. The same computer code was used in the current licensing basis containment temperature and pressure analyses. Therefore, we find the use of this code for calculating LOCA containment pressure and temperature response acceptable.

For the SGR/PU, the LOCA analyses calculated a containment peak pressure of 41.8 psig and a peak temperature of 270.2°F for the DEHLG case, and a containment peak pressure of 40.1 psig and a peak temperature of 261.8°F for the DEPSLG case. The LOCA analysis also showed that the containment pressure was reduced to less than 50 percent (7.8 psig) of the peak calculated pressure within 24 hours as required. The peak containment LOCA pressure at the current power level was 38.4 psig. The SGR/PU peak containment pressure of 41.8 PSIG and peak containment temperature of 270.2°F for LOCA remains below the containment design pressure of 45 psig and design temperature of 380°F. Based on the above, we find that the PU will not impact containment integrity for a design bases LOCA event.

The licensee has proposed to revise the HNP TS for containment leak rate testing based on the LOCA analyses calculated peak containment pressure of 41.8 psig as per 10 CFR 50, Appendix J. We find the proposed TS change acceptable.

7.2.18.3 Containment Integrity Analysis - MSLB

The licensee has performed analyses to determine the containment pressure and temperature response during postulated main MSLB inside containment for limiting conditions for operation at uprated power. As in the current HNP licensing basis FSAR, the SGR/PU analyses were evaluated for power levels and a spectrum of break sizes similar to that in the current FSAR. The MSLB mass and energy releases at the uprated power were calculated using the Westinghouse LOFTRAN computer code, which was also used in the current licensing basis analysis. We find the use of the LOFTRAN computer code for calculating MSLB mass and energy releases acceptable.

The mass and energy releases calculated from the above analyses were utilized for SGR/PU containment pressure and temperature response analyses using the Contempt LT/28 computer code. The same computer code was used in the current MSLB containment temperature and pressure analyses. Therefore, we find the use of this code for MSLB containment analyses acceptable.

For the SGR/PU, the MSLB analyses calculated a peak containment pressure of 41.3 psig and a peak containment temperature of 364.4°F. The peak containment temperature at the current power level was 368°F. The peak containment pressure at uprated conditions remains below the containment design pressure of 45 psig and design temperature of 380°F.

Based on the above evaluation, we find the proposed change for SGR/PU will not affect the containment design as the calculated peak containment pressure remains below the containment design pressure of 45 psig and the containment temperature will remain below its design temperature of 380°F. Therefore, we find that the SGR/PU will not impact containment integrity for a design bases MSLB event.

7.2.18.4 Short-Term Subcompartment Analysis

The licensee indicated that the short-term LOCA-related mass and energy releases that support subcompartment analyses were reviewed to assess the effects associated with PU. The reactor building subcompartments evaluated include the SG, reactor cavity, and pressurizer compartments. The HNP is approved for LBB, which eliminates the dynamic effects of postulated primary loop pipe ruptures from the design basis. This means that the current breaks (a double-ended circumferential rupture of the reactor coolant cold leg break for the SG compartments, and a 150 in^2 reactor vessel inlet break for the reactor cavity region) no longer have to be considered for the short-term effects. Since HNP is approved for LBB, the decrease in mass and energy releases associated with the smaller RCS nozzle breaks, as compared to the larger RCS pipe breaks, more than offsets the increased releases associated with the SGR/PU conditions. The current licensing basis subcompartment analyses that consider breaks in the primary loop RCS piping (SG subcompartment and reactor cavity region), therefore, remain bounding.

The licensee indicated that surge line and spray line breaks are postulated in the pressurizer compartment to evaluate subcompartement pressurization effects under SGR/PU since LBB methodology is only applied to large RCS piping. The licensee stated that the release rate from the spray line under the SGR/PU have increased but remains bounded by the values from the postulated surge line breaks. The forces and moment on the the pressurizer due to surge line break are much lower than those due to pump suction break because of the location of the break. Therefore, the forces and moments on the pressurizer are bounded by the pump

suction leg break in the SG compartment. The releases based on the SGR/PU conditions were bounded by the releases documented in the HNP FSAR, and the short-term pressurizer subcompartment loading analyses will remain acceptable.

Based on our review of the licensee's rationale and the experience gained from the review of PU applications from similar PWR plants, the staff agrees with the licensee's conclusion that plant operations at the proposed SGR/PU level will have an insignificant or no impact on the short-term subcompartment analysis.

7.2.19 Post-LOCA Hydrogen Control System

Hydrogen is generated following a LOCA inside containment from the zirconium-water reaction, radiolytic decomposition of the water in the core and containment sump, corrosion of materials inside the containment, and release of hydrogen dissolved in the reactor coolant. The licensee indicated that the effect of SGR/Uprate was reviewed for the above modes of post-LOCA hydrogen production and for comustible gas control system capability to maintain acceptable hydrogen concentration inside containment.

The post- LOCA hydrogen control system consists of two 100 percent capacity hydrogen recombiners, post-accident containment venting, containment mixing, and containment sampling. The hydrogen produced at the uprated power level was calculated according to the method described in FSAR 6.2.5 "Combustible gas control in containment." The revised analyses show approximately 95,000 standard cubic feet (scf) of hydrogen production at 12 days after a LOCA as opposed to 80,000 scf at the current power level. Relative to the results in the current FSAR, the revised input included the containment temperature increase into the hydrogen calculation, revised zirconium inventory from 36,795 lbs to 39,600 lbs, revised core-wide oxidation of the zirconium fuel cladding in accordance with the requirements of 10 CFR 50.46(b)(3), and revised hydrogen generated from radiolysis as per updated methodology provided in NUREG-0800.

The licensee indicated that although the impact of the PU on the combustible gas control system is an increase in the maximum hydrogen concentration in containment post-LOCA, the 4% hydrogen concentration limit is not exceeded. The PU design is able to maintain the hydrogen concentration below 4% provided a single hydrogen recombiner is actuated to operate after 4 days of post-accident when the hydrogen concentration in the containment reaches 3% and runs continuously thereafter.

The licensee also indicated that with no recombiner in operation, and assuming containment purge starts at 8 days post-LOCA and run continuously, hydrogen concentration is calculated to remain below 4% after SGR/PU. Therefore, the licensee determined that the SGR/PU does not impact the post-LOCA combustible gas control system's ability to maintain the hydrogen concentration below 4%.

Based on our review of the licensee's rationale and the experience gained from the review of PU applications from similar PWR plants, the staff agrees with the licensee's conclusion that plant operations at the proposed uprated power level will have an insignificant impact on the post-LOCA combustible gas control and the system will continue to perform its design function at the uprate power level.

7.2.20 Summary

Based on our review of the licensee's rationale and evaluation, our evaluations described above, and the experience gained from our review of PU applications for similar PWR plants, we conclude that HNP operations at the proposed SGR/PU is acceptable.

8.0 ELECTRICAL POWER

8.1 Background

The 230 kilo-Volt (kV) switchyard utilizes breaker-and-a-half and double-breaker schemes. The unit is connected in a double-breaker scheme. The switchyard is provided with two independent 125 Volts, direct current (Vdc) systems to furnish the control power for the circuit breakers. The supply for preferred (offsite) power is the 230 kV system. Seven 230 kV transmission lines connect to the transmission network. Each of the switchyard two 230 kV buses is a source of preferred power to the unit. The isolated phase bus is designed to deliver power from the generator terminals to the three single-phase transformers and is connected wye on the high voltage side and delta on the low voltage side.

The onsite electrical distribution system provides alternating current (ac) or dc power to plant electrical loads at various voltage levels. The onsite ac power distribution system receives power under normal operating conditions through the unit auxiliary transformers. Under startup and shutdown conditions, power is supplied through startup transformers. Four non-safety-related 6.9 kV switchgear buses (1A, 1B, 1D, and 1E) provide power from these transformers to the onsite electrical power distribution system. Switchgear buses 1D and 1E provide power to two independent safety-related switchgear buses, which provide power to the redundant safety-related electrical loads. Should the offsite power to these safety-related buses be unavailable, two EDGs supply onsite power to the safety-related buses. The electrical distribution system has been previously evaluated to conform to 10 CFR 50 Appendix A, General Design Criteria 17.

The main power system, onsite electrical power distribution systems, EDGs, SBO, and environmental qualification are evaluated.

8.2 Evaluation

8.2.1 Main Power System

The HNP steam turbine-driven generator is a 4-pole machine, rated at 1044 megavolt-amperes (MVA) at 0.9 power factor. At the uprated thermal rating of 2900 MWt, the main generator gross electrical output will be 998 megawatts electrical. There is no change to the output MVA level of the main generator. The electrical system associated with turbine auxiliary systems is within the design rating and is not affected by the uprate.

The Isolated Phase Bus is adequately rated for the uprate conditions.

The Isolated Phase Bus is designed to deliver power from the generator terminals to the three single-phase main power transformers (MPTs) and is connected wye on the high voltage side

and delta on the low voltage side. The net output to high-voltage side of the MPTs has increased from 906.3 MVA to 927.4 MVA with the power uprate. The MPTs are rated at 1008 MVA and are adequately rated for the uprate conditions.

8.2.2 Onsite Electrical Distribution system

There are no configuration changes associated with the onsite electrical distribution systems and main power system under the uprated condition. The licensee evaluated the onsite electrical distribution systems to ensure that following the uprate the systems can perform required functions by the existing licensing bases specified in the FSAR.

The licensee has provided a list of the load changes to the onsite electrical distribution system and the MPTs. This information was used to decide that the MPTs, unit auxiliary transformers, startup transformers, Isolated Phase Bus (ampacity and cooling), and large motors (reactor coolant pumps and condensate pump) will operate satisfactorily at the uprate conditions, and to verify that all station auxiliary loads will continue to perform their intended safety-related functions at the uprate condition. The evaluation revealed changes to the safety-related 6.9 kV ac distribution system due to uprate, and the changes in loads are bounded by the existing design. For the other ac electrical distribution system (i.e., the 480 Vac, 208/120 Vac, the Class 1E and non-Class 1E Uninterruptible Power Supplies) and the dc distribution systems, the evaluation identified no load changes due to uprate. The result of the analyses for the steady state voltages and motor-starting voltages remain within the acceptable limits. In addition, the rated nameplate horsepower for these pumps is greater than the horsepower load level at 100% power. The system buses, breakers, and transformers (startup and unit auxiliary) are bounded by the analyzed conditions.

The onsite electrical distribution systems and the main power systems are adequate for uprate conditions, since their design capabilities bound the uprate conditions. The uprate does not adversely affect system reliability and capacity. Therefore, the onsite electrical distribution systems and the main power system meet the required acceptance criteria and satisfy required functions, in accordance with the FSAR under uprate conditions.

The licensee evaluated the impact of uprate upon the transmission system connected to the plant switchyard for stability, thermal capability, and voltage adequacy. The licensee performed the load flow studies using scenarios with the existing and the uprated plant output conditions. These studies show negligible difference in transmission system voltage levels by limiting the net MVA reactive (MVAR) range to 55-155 MVAR for the uprated plant outputs. The results show only a negligible difference between the present and uprate range of switchyard and generator bus voltage levels with the net MVAR range of 55-155 MVAR after the uprate. Study cases show that plant switchyard voltage levels for the LOCA case and immediately after an unplanned unit trip under uprate conditions will not be lower than 0.06% those at the present output levels. The licensee also ran the stability cases to check several enveloping conditions and scenarios as in the FSAR. Study cases show that the plant exhibits a wide stability margin under the uprated conditions during a stuck-breaker fault considering the 2 cycles, 230 kV switchyard circuit breakers. The rate of grid frequency decay for the uprate was checked by assuming that all the generation is tripped while all of the ties in CP&L Eastern system are also opened. The results show that the system oscillations are well damped and the frequency decay rate at the plant switchyard is well within the acceptable limit.

8.2.3 Emergency Diesel Generators

There are no configuration changes associated with the EDGs under the uprate conditions. The EDGs provide vital power for a safe shutdown in case of loss of the preferred power source. Any transient that results in the need for EDG actuation will also result in a reactor trip. With the unit tripped, the electrical loads are identical to the non-uprated condition, so the emergency loads to the EDGs are not affected by the plant uprating.

8.2.4 Station Blackout

SBO is defined in 10 CFR 50.2 as the complete loss of preferred offsite and Class 1E onsite emergency ac power system. The licensee has determined that the plant's ability to cope with a postulated SBO requires no configuration change to the components and functions credited in the SBO coping assessments. The coping period for the uprate remains constant at 4 hours. The uprate does not impact the EDG target reliability of 0.95. Based on this, the uprate does not adversely affect the ability of the plant to mitigate a postulated SBO event in accordance with the existing FSAR licensing basis.

8.2.5 Environmental Qualification

As stated in the FSAR, equipment relied on to perform a necessary safety function can maintain function operability under all service conditions (including exposure to radiation) postulated to occur for the duration it is required to operate during its installed life. The licensee evaluated the effect of the uprate on equipment qualification that indicates that there are no changes in environmental conditions, except for exposure to the total integrated radiation doses and the accident/post-accident temperature/ pressure profile inside the containment and main steam line tunnel. These changes will not adversely impact the equipment qualification or design bases of equipment necessary for safe plant operations. They are bounded by equipment design limits and will not adversely diminish the capability of safety-related equipment in performing their intended safety function.

8.3 Summary

Based on the above evaluation, the staff concludes that the licensee has provided reasonable assurance that the safety functions and the environmental functions of the electrical power system will be maintained and would have a negligible impact on grid stability. This is consistent with GDC 17; therefore, the proposed change is acceptable.

9.0 INSTRUMENTATION AND CONTROL SYSTEMS

9.1 Background

The supporting analyses and evaluation were performed at core power level of 2900 MW_t. The analyses include setpoint study on some of the Functional Units of the Reactor Trip System (RTS) and the ESFAS trip setpoint and allowable values. The 10 CFR 50 Appendix K

requirements were considered in their analyses to account for uncertainties in instrument errors.

The instrumentation and interlocks of the RTS/ESFAS ensure that the associated reactor trip and/or safeguards actions are initiated when the monitored parameter reaches the trip setpoint. The trip setpoints listed in TS Tables 2.2-1 and 3.3-4 that ensure the core and RCS do not exceed their safety limits during normal operation and design-basis accidents, and initiate safeguards actions for mitigating accident consequence. The staff has reviewed the RTS and the ESFAS TS setpoint changes. By letter dated April 12, 2001, the staff requested the licensee to provide the HNP plant-specific instrument channel uncertainty calculations documentation that shows the detailed calculation of the proposed TS setpoint changes in TS Tables 2.2-1 and 3.3-4. By letter dated May 18, 2001 (Ref. 6), the licensee submitted a document, “Calculation No. HNP-I/INST-1010," that provides the evaluation of protection system instrument channels uncertainties associated with SGR/PU. The staff’s evaluation is based on information provided in Refs. 1 and 6.

9.2 Evaluation

The Commission’s regulatory requirements related to the contents of the TS are set forth in 10 CFR 50.36, “Technical Specifications.” This regulation requires that the TS include items in five categories. These categories include: 1) safety limits, limiting safety system settings and limiting control settings; 2) limiting conditions for operation (LCOs); 3) SRs; 4) design features; and 5) administrative controls. However, the regulation does not specify the particular TS to be included in a plant’s license.

Paragraph (c)(1)(ii)(A) of 10 CFR 50.36 requires in part that where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. Trip setpoint in nuclear safety-related instruments should be selected to provide sufficient allowance between the trip setpoint and the safety limit to account for uncertainties. The trip setpoint should be the value that the final setpoint device is set to actuate. The safety limit can be defined in terms of directly measured process variables such as pressure or temperature. Safety limit can also be defined in terms of a calculated variable involving two or more measured process variables. An example of a calculated variable is the DNBR.

The Instrument Society of America (ISA) Standard S67.04-1994, “Setpoint for Nuclear Safety-Related Instrumentation,” provides some guidance on instrument drift evaluation and uncertainty term development for the evaluation of an instrument surveillance interval. Section 4.3 of ISA-S67.04-1994 states that the limiting safety system setting (LSSS) may be the trip setpoint, an allowable value, or both. The nuclear industry Technical Specification Task Force (TSTF) recommended by TSTF Number 355 entitled, “Westinghouse Standard Technical Specifications - Reactor Trip System and Engineered Safety Feature Actuation Instrumentation,” that the allowable value be designated as LSSS. In association with the trip setpoint and LCOs, the LSSS establishes the threshold for protective system action to prevent acceptable limits being exceeded during DBAs. The LSSS ensures that automatic protective action will correct the abnormal situation before a safety limit is exceeded.

ISA-S67.04-1994 provides a discussion on the purpose and application of an allowable value. The allowable value is the limiting value that the trip setpoint can have when tested periodically,

beyond which the instrument channel is considered inoperable and corrective action must be taken in accordance with the TS. The allowable value relationship to the setpoint methodology and testing requirements in the TS must be documented.

As stated in the submittal, the proposed revision to the HNP TS on RTS/ESFAS setpoint and allowable values in Tables 2.2-1 and 3.3-4 is due to one of the following factors:

1. Physical differences between the RSG and the old SG, such as narrow range instrument tap elevations, primary/secondary volumes and heat transfer characteristics, require changes to certain trip setpoints and allowable values. The setpoints and associated values for SG water level trip functions are affected by these differences.

2. Overtemperature ΔT (OT ΔT) and Overpower ΔT (OP ΔT) setpoint terms and time constants are changed as a result of applying Westinghouse margin improvement methodology.

3. Transient and accident analyses were performed to support revised DNBR margin.

4. Changes to TA terms reflect increases to safety analysis limits used for the analyses.

5. Changes to RTS/ESFAS table values for Z, S, and allowable value (AV) are based on instrument channel uncertainty calculations.

6. Other changes on RTS/ESFAS table values reflect the results of calculations based on RSG process measurement uncertainties.

Owing to the existing HNP licensing Bases, the TS Tables 2.2-1 and 3.3-4 on RTS/ESFAS trip setpoint tables will be retained in their original “five-column” format. This “five-column” TS formatted methodology utilizes the following terms:

- Trip Setpoint “TS”: A predetermined value for actuation of the final setpoint device to initiate a protective action. Considered a nominal reactor trip value setting.

- Allowable Value “AV”: Accommodates instrument drift assumed between operational tests and the accuracy to which trip setpoint can be measured and calibrated. A limiting value that the trip setpoint may have when tested periodically, beyond which appropriate action shall be taken.

- “Z” term: Statistical summation of analysis errors excluding Sensor and Rack Drift and Calibration Uncertainties.

- Sensor Error “S” term: Sensor drift and calibration uncertainties.

- Total Allowance “TA”: Difference (in percent of span) between Trip Setpoint and Safety Analysis Limit (SAL) assumed for reactor trip function; e.g., TA = $|TS-SAL|$. Defined within TS equation 2.2-1 ($Z+R+S \leq TA$); where “R” includes Rack Drift and Calibration Uncertainties.

The last three terms: “Z”, “S”, and “TA,” were intended to further quantify channel operability by demonstrating that sufficient margin exists from the safety analysis limit.

With respect to the instrument uncertainty, the basic methodology used by the licensee is the “square-root-sum-of-the-squares” (SRSS) technique. The methodology used to combine the uncertainty components for a channel is an appropriate combination of those groups that are statistically and functionally independent. Those uncertainties that are not independent are conservatively treated by arithmetic summation and then combined with the independent terms. This methodology is following the guidance from the ISA standard S67.04-1994, “Setpoint for Nuclear Safety-Related Instrumentation.” NRC RG 1.105, “Setpoint for Safety-Related Instrumentation,” Revision 3, 1999, endorses the 1994 version of ISA S67.04.

In Ref. 6, the licensee stated that the existing plant modification procedure provides programmatic requirements to maintain the accuracy of setpoint documentation with respect to design change reviews and subsequent implementation associated with the protection system. This procedure contains a screening criteria process, which includes instrumentation and control setpoints and time response. The design engineer must determine if the proposed modification will:

- affect the response time characteristics of equipment that are part of a required reactor trip or ESFs response time?

- affect any actuation or interlock circuit components that are part of a surveillance test used to verify operability of a reactor trip or ESFs actuation systems?

- affect any setpoints or margins to setpoints?

RTS/ESFAS-related setpoints are implemented only after scaling documents, surveillance test procedures, and the engineering data base are revised to reflect the new setpoints. In addition, the Westinghouse NSSS Precautions, Limitations, and Setpoint document is maintained at HNP as a “living” document.

Due to demonstrated compliance with 10 CFR 50.36, adherence to the guidance contained in RG 1.105, ISA Standard S67.04, 1994, and appropriate modeling and maintenance of uncertainties, the staff finds that the methodology for establishing revised RTS and ESFAS trip setpoints and AVs is acceptable.

The staff has verified the proposed trip setpoint values and the AVs with the setpoint calculation document HNP - I/INST-1010, “Evaluation of Tech Spec Related Setpoints, Allowable Values, and Uncertainties for Steam Generator Replacement.” The AVs are being modified due to the plant-specific analyses, which resulted in changes to the uncertainties used in the determination of the AVs. The trip setpoint values and the AVs listed in the proposed changes are consistent with the setpoint calculation documentation. The staff also reviewed the justifications in the submittal related to the requested changes to reach the acceptable conclusion.

The following reactor trip setpoint limits, AVs, Z-term, S-term, or TA values specified in TS Table 2.2-1 are affected by the setpoint study associated with SGR/PU:

(1) Functional Unit 3: Power Range Neutron Flex High Positive Rate

TA value changed from 1.6 to 2.5% span, Z-term value changed from 0.5 to 0.83% span.

(2) Functional Unit 4: Power Range Neutron Flex High Negative Rate

TA value changed from 1.6 to 2.5% span, Z-term value changed from 0.5 to 0.83% span.

(3) Functional Unit 7: Overtemperature ΔT

TA value changed from 8.7 to 9.0% of span, Z-term changed from 6.02 to 7.31% of span. Time constants utilized in lead-lag compensator, lag compensator for ΔT are set to 0. Constant K_1 changed from 1.17 to 1.185. Time constants utilized in the lead-lag compensator for T_{avg} τ_4 changed from 20 to 22 seconds. T' = Reference T_{avg} at rated thermal power ($\leq$ 588.8 F). K_3 changed from 0.001072 to 0.0012 /psig. Note 2 was revised as followed: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 1.4% of ΔT span for ΔT input; 2.0% of ΔT span for Tavg input; 0.4% of ΔT span for pressurizer pressure input; and 0.7% of ΔT span for ΔT input.

(4) Functional Unit 8: Overpower ΔT

TA value changed from 4.7 to 4.0% of span, Z-term changed from 1.50 to 2.32% of span. S-term changed from 1.9 to 1.3% of span. Constant K_4 changed from 1.079 to 1.12. Time constant τ_7 changed from 10 to 13 seconds. T" = Reference T_{avg} at rated thermal power ($\leq$ 588.8F). Note 4 was revised as follows: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 1.4% of Δspan for ΔT input and 0.2% of ΔT span for Tavg input. Note 5 was revised as follows: The sensor error is: 1.3% of ΔT span for ΔT/Tavg temperature measurements; and 1.0% of ΔT span for pressurizer pressure measurements. Note 6 was revised as follows: The sensor error (in % span of steam flow) is: 1.1% for steam flow; 1.8% for feedwater flow; and 2.4% for steam pressure.

(5) Functional Unit 9: Pressurizer Pressure - Low, Reactor Trip

Z-term changed from 2.21 to 1.52% of span. AV changed from 1946 to 1948 psig.

(6) Functional Unit 10: Pressurizer Pressure - High, Reactor Trip

Z-term changed from 5.01 to 1.52% of span. S-term change from 0.5 to 1.5% of span. AV changed from 2399 to 2397 psig.

(7) Functional Unit 11: Pressurizer Water Level - High, Reactor Trip

Z-term changed from 2.18 to 3.42% of span. S-term changed from 1.5 to 1.75% of span. AV changed from 93.8 to 93.5% of span.

(8) Functional Unit 12: Reactor Coolant Flow - Low, Reactor Trip

TA Value changed from 2.9 to 4.58% of span.

(9) Functional Unit 13: SG Water Level - Low-Low, Reactor Trip

TA Value changed from 19.2 to 25.0% of span. Z-term changed from 14.06 to 16.85% of span. S-term changed from 2.97 to 2.0% of span. Trip setpoint changed from 38.5 to 25.0% of span. AV changed from 36.5 to 23.5% of span.

(10) Functional Unit 14: SG Water Level Low coincident with steam/feedwater/feedwater Flow Mismatch

TA Value changed from 19.2 to 8.9% of span. Z-term changed from 2.23 to 5.35% of span. S-term changed from 2.97 to 2.0% of span. Trip setpoint changed from 38.5 to 25.0% of span. AV changed from 36.5 to 23.5% of span. For steam/feedwater mismatch channels, the sensor error is 1.1% of span for steam flow, 1.8% of span for feedwater flow, and 2.4% of span for steam pressure. Z-term is changed from 3.41 to 3.01% of span.

The following ESFAS instrumentation trip setpoints, allowable values, Z-term, S-term, or TA values specified in TS Table 3.3-4 are affected by the setpoint study associated with SGR/PU:

(1) Functional Unit 1.c.: SI - Containment Pressure High-1

TA value changed from 2.7 to 3.64% of span.

(2) Functional Unit 1.d.: SI - Pressurizer Pressure Low

TA value changed from 18.8 to 18.75% of span. Z-term changed from 14.41 to 10.47% of span. AV changed from 1836 to 1838 psig.

(3) Functional Unit 1.e.: SI - Steam Line Pressure Low

TA value changed from 17.7 to 4.75% of span. Z-term change from 14.81 to 0.71% of span. S-term changed from 1.5 to 2.0% of span. AV changed from 570.3 to 581.5 psig.

(4) Functional Unit 2.c.: Containment Spray - Containment Pressure High - 3

TA value changed from 3.6 to 3.64% of span.

(5) Functional Unit 3.(4): Containment Radioactivity

The proposed changes in this item are editorial changes.

(6) Functional Unit 4.c.: Main Steam Line Isolation - Containment Pressure High-2

TA value changed from 2.7 to 3.64.

(7) Functional Unit 4.e.: Main Steam Line Isolation - Negative Steam Line P Rate High

AV changed from 122.8 to 119.5 psi.

(8) Functional Unit 5.b.: Turbine Trip and FeedWater Isolation - SG Level High-High

TA value changed from 15.0 to 22.0% of span. Z-term changed from 11.25 to 9.63% of span. S-term changed from 2.97 to 2.0% of span. Trip setpoint changed from 82.4 to 78.0% of span. AV change from 84.2 to79.5% of span.

(9) Functional Unit 6.c.: AFW Initiation - SG Level Low-Low

TA value changed from 19.2 to 25.0% of span. Z-term changed from 14.06 to 16.85% of span. S-term from 2.97 to 2.0% of span. Trip setpoint changed from 38.5 to 25.0% of span. AV changed from 36.5 to 23.5% of span.

(10) Functional Unit 6.g.: AFW Initiation - Steam Line Differential P High

Z-term changed from 1.47 to 0.87% of span.

(11) Functional Unit 10.a.: ESFAS Interlocks - P-11, Pressurizer Pressure

AV on increasing pressure changed from 1986 to 1988 psig. AV on decreasing pressure changed from 2014 to 2012 psig.

Based on our review of the information submitted on the docket, the staff finds that the OTΔT trip function provides sufficient core protection to preclude DNB over a range of transient conditions. The OPΔT trip function provides assurance of fuel integrity under all possible overpower conditions. The effects of SGR, higher power rating, a larger range of average RCS temperature, and other parameter changes are factored into the revised setpoints. The methodology used in developing these variable setpoints is following the guidance from the ISA standard S67.04-1994. That is in compliance with Paragraph (c)(1)(ii)(A) of 10 CFR 50.36; therefore, the above listed changes are acceptable.

9.3 Summary

The licensee has performed plant-specific analyses to recalculated each protective function trip setpoint and AV. The detailed setpoint calculation is documented in HNP-I/INST-1010. The staff has reviewed this document and related justifications and concluded that the revised trip setpoints and AVs are acceptable.

10.0 HUMAN FACTORS

10.1 Evaluation

10.1,1 Background

The staff's evaluation of the licensee's submittal regarding the request for a license amendment to permit a PU, as it relates to operator licensing and human performance based on five review topic areas, is as follows.

10.1.2 Changes in Emergency and Abnormal Operating Procedures

In a supplemental response submitted by the licensee (Ref. 26), the licensee indicated that, “The basic structure of the Harris Emergency Operating Procedures (EOPs) is not changed by the proposed PU. The type and nature of operator actions needed for accident mitigation will not change, and no new operator actions will be required for the proposed PU.” However, several changes will be made, before the implementation of PU, to Emergency Response Guideline footnote values applicable to PU. “The PU does not change the structure or content of the abnormal operating procedures."

The staff finds that the licensee’s response is satisfactory because the licensee has adequately identified the type and scope of plant procedures that will be affected by the uprate, indicated that the procedures will be appropriately revised and operators will be trained on the changes before the procedures are implemented, and adequately described the effect of the changes on operator actions.

10.1.3 Changes to Risk-Important Operator Actions Sensitive to PU

The licensee stated in Ref. 26, that, “PU did not add any new risk-important operator actions. No automation of current manual operator actions is planned as a result of the power uprate.” In Ref. 27, the licensee stated, “If new or changes to risk important operator actions are identified as a result of the proposed power uprate, they will be evaluated for inclusion in the HNP PSA model. Any changes that require the PSA model to be updated will be incorporated in our on-line risk model (EOOS) prior to entering Mode 3 after the SGR/PU outage.”

A few changes resulted in changes for the operator action times related to the design basis SGTR analysis. “The licensee stated, however, as a result of PU, the time available to initiate RCS cooldown to use LPSI/RHR during a SGTR has changed. The operator’s ability to complete SGTR mitigating actions within the time requirements specified by the accident analysis for PU has been demonstrated....”

In a June 22, 2001, telephone conversation, at the staff’s request, the licensee provided operator response time demonstration data for all crews related to actions needed to respond to a SGTR. The staff questioned that one crew slightly exceeded two actions to isolate AFW and isolate steam flow to the ruptured SG. In Ref. 27, the licensee submitted additional information, which explained why the first crew’s performance was satisfactory. “The difference in response times was due primarily to differences in the procedures used by the crews, not to any inadequacy in the performance of Week 1 crew. In addition to moving the instructions to isolate AFW to the ruptured SG forward in the step sequence, the following enhancements were made to eliminate and/or bypass steps that were redundant or not applicable to the design basis SGTR scenario.... The validation results, the additional enhancements and detailed training should provide assurance that all operating crews can achieve the response times specified in the SGTR overfill analysis.”

In Ref. 27, the licensee stated, "A review was performed of current operator workarounds to determine if they could individually or in combination adversely impact the operator response times for a design basis SGTR. No item currently exists that could potentially impact these items."

The staff finds that the licensee's response is satisfactory because the licensee has adequately addressed the question of operator actions sensitive to the PU by describing the effect of the PU on operator performance and adequately justifying the effect/lack of effect on required operator response.

10.1.3 Changes to Control Room Controls, Displays, and Alarms

In Ref. 26, the licensee stated that, "The proposed power uprate will have very limited impact on the operator interfaces for control room controls, displays and alarms. The HNP plant modification process will assure that implementation of minor scaling and setpoint differences are addressed through programmatic reviews, which include those for human factors, operational training considerations, process computer [ERFIS/SPDS] database changes, and simulator configuration control." Zone markings are not currently used on main control board or auxiliary control panel meters. "PU implementation will lead to minor changes in several plant parameters." With only a few exceptions, renormalizing the instrument channel outputs will be transparent to the operator. "Each normalized parameter generally retains its respective pre-PU setpoint allowance. Operators become knowledgeable of, and are tested on, plant (and simulator) design configuration changes through operator re-qualification training. No specific analog-to-digital equipment upgrades will be performed to implement PU operation."

The staff finds that the licensee's response is satisfactory because the licensee has adequately identified the changes that will occur to alarms, displays, and controls as a result of the PU and adequately described how these changes will be accommodated.

10.1.4 Changes in Safety Parameter Display System (SPDS)

The licensee has indicated that, "The plant modification development and review process is used to identify any required changes to SPDS, site procedures, simulator configuration control, and operator training modules. The plant staff has reviewed the SPDS computer point list to identify any PU-related changes. The result of the review is that no SPDS setpoint changes are anticipated as a result of the power uprate."

The staff finds that the licensee's response is satisfactory because the licensee has identified that no changes to the SPDS will be necessary as a result of the PU.

10.1.5 Changes to the Operator Training Program and the Control Room Simulator

The licensee stated that, "The plant-specific simulator will be modified during two simulator outage periods to implement PU changes." The outages are scheduled for the third quarter of 2001 and early in the fourth quarter of 2001. The outages will incorporate the required changes due to PU. One additional simulator outage following the refueling outage is planned to make

any software or hardware changes resulting from plant operating data gathered during startup testing associated with PU. “The Harris Operations Training Unit will conduct classroom and simulator training as part of the Licensed Operator Re-qualification and Non-licensed Operator Training Programs to address Power Uprate changes. Simulator training for Licensed Operators will be provided just prior to the Refueling Outage as well as during the outage. Additional training will be conducted following the Refueling Outage to address any training issues relating to Startup Testing associated with PU.”

The staff finds the licensee’s response satisfactory because the licensee has adequately described how the changes to operator actions will be addressed by the simulator and how the simulator will accommodate the changes.

10.2 Summary

The staff concludes that the previously discussed review topics associated with the proposed PU have been satisfactorily addressed. The staff further concludes that the PU should not adversely affect simulation facility fidelity, operator performance, or operator reliability.

11.0 STATE CONSULTATION

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

12.0 ENVIRONMENTAL CONSIDERATION

With respect to the portion of the amendment related to the PU, pursuant to 10 CFR 51.21, 51.32, and 51.35, an environmental assessment and finding of no significant impact has been prepared and published in the *Federal Register* on , 2001 (66 FR). Accordingly, based upon the environmental assessment, the NRC staff has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

With respect to the portions of the amendment related to the SGR and AST, the amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes the Surveillance Requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (65 FR 65338 dated November 1, 2000, for the SGR amendment; and 66 FR 41612 dated August 8, 2001, for revision to the analyses of radiological consequences). The March 8, 2001, March 27, April 26, May 14, May 18, June 4, June 11, June 26, June 29, July 3, July 16 (2 letters), July 17, August 17, and September 20, 2001, supplements contained clarifying information only, and did not change the initial no significant hazards consideration determination, or expand the scope of the initial applications. Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

13.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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14.0 REFERENCES

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