ENT000652
Submitted: August 10, 2015

October 27, 2004

Mr. Michael R. Kansler, President
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

SUBJECT: INDIAN POINT NUCLEAR GENERATING UNIT NO. 2 - ISSUANCE OF AMENDMENT RE: 3.26 PERCENT POWER UPRATE (TAC NO. MC1865)

Dear Mr. Kansler:

The Commission has issued the enclosed Amendment No. 241 to Facility Operating License No. DPR-26 for the Indian Point Nuclear Generating Unit No. 2 (IP2). The amendment consists of changes to the Technical Specifications (TSs) in response to your application transmitted by letter dated January 29, 2004, as supplemented by letters dated April 12, June 16, June 30, July 16, August 3, August 12, and September 24, 2004.

The amendment revises the IP2 operating license and TSs to increase the licensed rated power by 3.26 percent from 3114.4 megawatts thermal to 3216 megawatts thermal.

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

Sincerely,

/RA/

Patrick D. Milano, Sr. Project Manager, Section 1
Project Directorate I
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-247

Enclosures: 1. Amendment No. 241 to DPR-26
2. Safety Evaluation

cc w/encls: See next page

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cc w/encls: See next page

Accession No.: ML042960007 Package No.: ML043020362 TSs:

OFFICE	PDI-1/PM	PDI-1/LA	SPLB/SC	SPLB/SC	EMCB/SC	EMCB/SC	EMCB/SC	EEIB/SC	EEIB/SC
NAME	PMilano	SLittle	SWeerakkody	JHerrity	SCoffin	TChan	LLund	EMarinos	RJenkins
DATE	10/08/04	10/08/04	SE dtd 07/31/04	SE dtd 10/01/04	SE dtd 10/01/04	SE dtd 09/20/04	SE dtd 08/30/04	SE dtd 08/18/04	SE dtd 08/23/04

OFFICE	IEHB/SC	EMEB/SC	SRXB/SC	SPSB/SC	IROB/SC	OGC	PDI-1/SC	PDI/D	DLPM/D
NAME	DTrimble	KManoly	JUhle	RDenning	TBoyce	SLewis	RLaufer	CHolden	TMarsh
DATE	10/09/04	SE dtd 09/16/04	SE dtd 09/22/04	SE dtd 08/11/04 and 09/01/04	10/13/04	10/21/04	10/22/04	10/24/04	10/26/04

Official Record Copy

DATED: October 27, 2004

AMENDMENT NO. 241 TO FACILITY OPERATING LICENSE NO. DPR-26 INDIAN POINT UNIT 2

PUBLIC
PDI-1 R/F
C. Holden
R. Laufer
P. Milano
S. Little
T. Boyce
G. Matakas, R-I
J. Uhle
J. Herrity
S. Weerakkody
S. Coffin
T. Chan
L. Lund
E. Marinos
R. Jenkins
K. Manoly
R. Dennig
D. Trimble
J. Stang
G. Hill (2)
ACRS
OGC

cc: Plant Service list

Indian Point Nuclear Generating Unit No. 2

cc:

Mr. Gary J. Taylor
Chief Executive Officer
Entergy Operations, Inc.
1340 Echelon Parkway
Jackson, MS 39213

Mr. John T. Herron
Senior Vice President and
Chief Operating Officer
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Fred Dacimo
Site Vice President
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 2
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Christopher Schwarz
General Manager, Plant Operations
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Danny L. Pace
Vice President Engineering
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Brian O'Grady
Vice President, Operations Support
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. John McCann
Director, Nuclear Safety Assurance
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Ms. Charlene D. Faison
Manager, Licensing
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. Michael J. Colomb
Director of Oversight
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Mr. James Comiotes
Director, Nuclear Safety Assurance
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

Mr. Patric Conroy
Manager, Licensing
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
295 Broadway, Suite 1
P. O. Box 249
Buchanan, NY 10511-0249

Mr. John M. Fulton
Assistant General Counsel
Entergy Nuclear Operations, Inc.
440 Hamilton Avenue
White Plains, NY 10601

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Senior Resident Inspector's Office
Indian Point 2
U. S. Nuclear Regulatory Commission
P.O. Box 59
Buchanan, NY 10511-0038

Indian Point Nuclear Generating Unit No. 2

cc:

Mr. Peter R. Smith, President
New York State Energy, Research, and
Development Authority
17 Columbia Circle
Albany, NY 12203-6399

Mr. Paul Eddy
Electric Division
New York State Department
of Public Service
3 Empire State Plaza, 10th Floor
Albany, NY 12223

Mr. Charles Donaldson, Esquire
Assistant Attorney General
New York Department of Law
120 Broadway
New York, NY 10271

Mayor, Village of Buchanan
236 Tate Avenue
Buchanan, NY 10511

Mr. Ray Albanese
Executive Chair
Four County Nuclear Safety Committee
Westchester County Fire Training Center
4 Dana Road
Valhalla, NY 10592

Ms. Stacey Lousteau
Treasury Department
Entergy Services, Inc.
639 Loyola Avenue
Mail Stop: L-ENT-15E
New Orleans, LA 70113

Mr. William DiProfio
PWR SRC Consultant
139 Depot Road
East Kingston, NH 03827

Mr. Dan C. Poole
PWR SRC Consultant
20 Captains Cove Road
Inglis, FL 34449

Mr. William T. Russell
PWR SRC Consultant
400 Plantation Lane
Stevensville, MD 21666-3232

Mr. Alex Matthiessen
Executive Director
Riverkeeper, Inc.
25 Wing & Wing
Garrison, NY 10524

Mr. Paul Leventhal
The Nuclear Control Institute
1000 Connecticut Avenue NW
Suite 410
Washington, DC, 20036

Mr. Karl Coplan
Pace Environmental Litigation Clinic
78 No. Broadway
White Plains, NY 10603

Mr. Jim Riccio
Greenpeace
702 H Street, NW
Suite 300
Washington, DC 20001

Mr. Robert D. Snook
Assistant Attorney General
State of Connecticut
55 Elm Street
P.O. Box 120
Hartford, CT 06141-0120

Indian Point Nuclear Generating Unit No. 2

cc:

Mr. David Lochbaum
Nuclear Safety Engineer
Union of Concerned Scientists
1707 H Street NW, Suite 600
Washington, DC 20006

ENTERGY NUCLEAR INDIAN POINT 2, LLC

ENTERGY NUCLEAR OPERATIONS, INC.

DOCKET NO. 50-247

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 241
License No. DPR-26

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

   A. The application for amendment by Entergy Nuclear Operations, Inc. (the licensee) dated January 29, 2004, as supplemented by letters dated April 12, June 16, June 30, July 16, August 3, August 12, and September 24, 2004, 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. DPR-26 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 241, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance, and is to be implemented within 30 days of the date of issuance. Implementation shall include revisions to plant procedures and the completion of operator training on the proposed power uprate as described in the licensee's January 29, 2004, application.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Ledyard B. Marsh, Director
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications and Facility
Operating License

Date of Issuance: October 27, 2004

ATTACHMENT TO LICENSE AMENDMENT NO. 241

FACILITY OPERATING LICENSE NO. DPR-26

DOCKET NO. 50-247

Replace the following page of the Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

Remove Page	Insert Page
3	3

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

Remove Pages	Insert Pages
1.1-2	1.1-2
1.1-4	1.1-4
3.3.1-12	3.3.1-12
3.3.1-13	3.3.1-13
3.3.1-14	3.3.1-14
3.3.1-16	3.3.1-16
3.3.1-17	3.3.1-17
3.3.2-6	3.3.2-6
3.3.2-8	3.3.2-8
3.3.2-9	3.3.2-9
3.4.1-1	3.4.1-1
3.4.1-2	3.4.1-2
3.4.9-1	3.4.9-1
3.4.9-2	3.4.9-2
3.5.1-2	3.5.1-2
3.5.4-2	3.5.4-2
3.7.1-1	3.7.1-1
3.7.1-3	3.7.1-3
5.6-3	5.6-3
5.6-4	5.6-4
5.6-5	5.6-5

Indian Point Nuclear Generating Unit No. 2

Safety Evaluation for Amendment No. 241

Regarding 3.26% Power Uprate

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 241 TO FACILITY OPERATING LICENSE NO. DPR-26

ENTERGY NUCLEAR OPERATIONS, INC.

INDIAN POINT NUCLEAR GENERATING UNIT NO. 2

DOCKET NO. 50-247

1.0 INTRODUCTION

By application dated January 29, 2004 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML040350111), as supplemented on April 12, June 16, June 30, July 16, August 3, August 12, and September 24, 2004 (ADAMS Accession Nos. ML041110037, ML041750538, ML041820289, ML042100346, ML042260497, ML042380253, and ML042720432), Entergy Nuclear Operations, Inc. (the licensee) submitted a request for changes to the Indian Point Nuclear Generating Unit No. 2 (IP2) Technical Specifications (TSs). The proposed amendment would increase the licensed reactor core power level by 3.26 percent from 3114.4 megawatts thermal (MWt) to 3216 MWt. Based on its review of this application, the Nuclear Regulatory Commission (NRC) staff categorized the application as a stretch power uprate (SPU). The modifications required to achieve the 3.26 percent SPU at IP2 are planned for the next refueling outage.

Specifically, the following are the proposed changes:

1. The rated thermal power (RTP) on page 3 of the Facility Operating License would change from 3114.4 MWt to 3216 Mwt.

2. Dose Equivalent 1-131, TS Section 1.1:

   The definition would be changed to be more consistent with the dose analysis methodology previously adopted by Amendment No. 211, issued on July 27, 2000, regarding adoption of the alternate source term.

3. RTP value in TS Section 1.1 would be changed from 3114.4 MWt to 3216 MWt.

4. Changes in Allowable Values in Table 3.3.1-1 (RPS Instrumentation):

   - Function 2.a, Power Range Neutron Flux (high). The allowable value would change from ˜ 112.6% RTP to ˜ 110.6%

   - Function 9, Reactor Coolant Flow - low. The allowable value would change from š 88.8% to š 88.7%

- Function 13, Steam Generator Water Level - low-low. The allowable value would change from š 3.7% to š 3.4%

- Function 14, Steam Generator Water Level - low. The allowable value would change from š 3.7% to š 3.4%

- Function 5, Overtemperature ªT. The allowable value in Note 1 for this function would change from 3.3% to 4.9%.ªT span. Also, the definition of T_o and T' parameters would clarify that loop specific values, not average values, are used.

- Function 6, Overpower ªT. The allowable value in Note 2 for this function would change from 2.3% to 2.4% ªT span. Also, the definition of T_o and T" parameters would be revised as stated in the proposed change for Note 1.

The above proposed changes in allowable values reflect updated uncertainty values for the affected instrument loops and/or changes in safety analysis limit assumptions used in analyses for the proposed stretch uprate conditions. The proposed change for Functions 13 and 14 addresses the industry operating experience regarding measurement uncertainty for steam generator water level.

5. Changes in Allowable Values in Table 3.3.2-1 (Engineered Safety Features Actuation System (ESFAS) Instrumentation):

- Function 1.f, High Steam Flow - Safety Injection, Coincident with Tavg -low. The allowable value would change from š 540.75 EF to š 540.5 EF.

- Function 1.g, High Steam Flow - Safety Injection, Coincident with Steamline Pressure - low. The allowable value would change from š 425.0 psig to š 540.3 psig.

- Functions 1.f, 1.g, 4.d, and 4.e. In Note (b) regarding turbine first stage pressure, the allowable values would be revised to state as follows:

  Less than or equal to turbine first stage pressure corresponding to 45.9% full steam flow below 20% load, and increasing linearly from 45.9% full steam flow at 20% load to 122.0% full steam flow at 100% load, and 122.0% full steam flow above 100% load.

- Function 4.d, High Steam Flow - Steam Line Isolation, Coincident with Tavg - low. The allowable value would change from š 540.75 EF to š 540.5 EF.

- Function 4.e, High Steam Flow - Steam Line Isolation, Coincident with Steam Line pressure - low. The allowable value would change from š 425.0 psig to š 540.3 psig.

- Function 5.b, Feedwater Isolation, SG Water Level - high-high. The allowable value would change from ˜ 77.7% to ˜ 88.3%.

- Function 6.b, Auxiliary Feedwater, SG Water Level - low-low. The allowable value would change from š 3.7% to š 3.4%.

The above proposed changes in allowable values reflect updated uncertainty values for the affected instrument loops and/or changes in safety analysis limit assumptions used in analyses for the proposed stretch uprate conditions. The change for Functions 1.g and 4.d reflect an increase in the safety analysis limit from 400 psig to 513 psig for the steam line break analysis. The change for Function 5.b reflects an increase in the safety analysis limit from 80% to 90% steam generator water level.

The licensee stated that a change to TS Bases Section 3.3.2 is needed to reflect the new values used in Note (b) regarding turbine first stage pressure.

6. Revise limiting condition for operation (LCO) and related surveillance requirement (SR) limit for minimum reactor coolant system (RCS) flow (TS 3.4.1)

   The licensee stated that the existing TS value corresponds to a 'minimum measured flow' that includes uncertainty allowances. The proposed value is the current RCS thermal design flow (TDF), which has not changed for SPU conditions. Updating the TSs to show TDF versus minimum measured flow is consistent with WCAP-14483, “Generic Methodology for Expanded Core Operating Limits Report [COLR],” for use of an expanded COLR, which was adopted during the recent conversion to the Standard TSs (STS). Associated TS Bases Section 3.4.1 would be revised to support this change.

7. Revise LCO and SR limit for maximum pressurizer water level (TS 3.4.9)

   The proposed change reflects the pressurizer water level corresponding to the maximum value of Tavg (572 EF) supported by stretch power analyses. Corresponding changes are proposed for TS Bases Section 3.4.9.

8. Revise SR for maximum boron concentration for accumulators (TS 3.5.1)

   Maximum boron concentration increased from 2500 parts per million (ppm) to 2600 ppm to be consistent with the analysis supporting the uprate. The higher boron concentration provides increased flexibility in future core designs, such as reducing the amount of burnable poisons needed.

9. Revise SRs for refueling water storage tank (RWST) temperature and boron concentration (TS 3.5.4)

   The increase in maximum RWST temperature, from ˜ 100 EF to ˜ 110 EF, provides additional operational margin for RWST conditions that may be experienced in the summer months. The proposed temperature is used in affected SPU safety analyses.

   RWST Boron Concentration range would change from š 2000 ppm and ˜ 2500 ppm to š 2400 ppm and ˜ 2600 ppm. As stated above for the change to accumulator boron concentration, these values provide additional flexibility for core design and are

consistent with and supported by the analysis for the uprate. Corresponding changes are needed for TS Bases Section 3.5.4.

10. Revise LCO for power limitations with inoperable main steam safety valves (MSSVs) (TS 3.7.1)

    The licensee proposed changes to reflect new limits corresponding to the slightly higher steam flow at SPU conditions. No changes are needed for Bases 3.7.1.

11. Revise references for the COLR (TS 5.6)

    The proposed change updates the reference listing for SPU analyses.

The April 12, June 16, July 16, August 3, August 12, and September 24, 2004, supplements provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on March 2, 2004 (69 FR 9859).

2.0 BACKGROUND

Nuclear power plants are licensed to operate at a specified core thermal power. IP2 was initially licensed to operate at a maximum of 2758 MWt. However, various systems and components were designed to accommodate the conditions associated with a power level of 3216 MWt. On March 7, 1990, the NRC staff authorized the licensee to increase licensed thermal power to 3071.4 MWt. In May 2003, the NRC staff approved a 1.4% measurement uncertainty recapture power uprate, which allowed an increase in the licensed power level from 3071.4 MWt to 3114.4 MWt. (Reference 20). The proposed SPU of 3.26% will allow the licensed rated power to be increased from the current value of 3114.4 MWt to 3216 Mwt.

3.0 REGULATORY AND TECHNICAL EVALUATION

In several places in this safety evaluation (SE), the NRC staff refers to NUREG-0800, "Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants LWR [light-water reactor] Edition," as guidance used during the review. The NRC staff notes that the SRP was used solely for general technical guidance. The licensee's January 29, 2004, application, as supplemented on June 16, June 30, July 16, August 3, August 12, and September 24, 2004, was reviewed for compliance with the IP2 licensing basis, not NUREG-0800.

3.1 Instrumentation and Controls

3.1.1 Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (control rods), (3) to initiate the engineered safety feature (ESF) systems and essential auxiliary supporting systems, and (4) to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of

protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducts a review of the reactor trip system, ESFAS, safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed power uprate to ensure that the systems and any changes required for the proposed power uprate are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review is also conducted to ensure that failures of the systems do not affect safety functions.

Nuclear power plants are licensed to operate at a specified core thermal power. The measurement uncertainties are considered at that power level to avoid exceeding the power levels assumed in the design basis transient and accident analysis. Furthermore, the safety trip setpoints are calculated to ensure that sufficient allowance exists between the trip setpoint and the safety limit to account for instrument uncertainties. The Commission's regulatory requirements related to this review can be found in Title 10 of the *Code of Federal Regulations* (10 CFR) as follows:

- 10 CFR 50.36(c)(1)(ii)(A) requires 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 most severe abnormal situation anticipated without exceeding a safety limit. Limiting safety system settings are settings for automatic protective devices related to variables having significant safety functions. Setpoints found to exceed TSs limits are considered a malfunction of an automatic safety system. Such an occurrence could challenge the integrity of the reactor core, reactor coolant pressure boundary, containment, and associated systems.

- Regulatory Guide (RG) 1.105, Revision 3, "Setpoint for Safety-Related Instrumentation," is used to evaluate the conformance with 10 CFR 50.36.

- The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and General Design Criteria (GDCs) 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

3.1.2 Technical Evaluation

3.1.2.1 Suitability of Existing Instruments

The IP2 reactor protection system (RPS) initiates a reactor shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and the RCS pressure boundary during anticipated operational occurrences (AOOs) and to assist the ESF systems in mitigating accidents.

The RPS is designed to trip the reactor by de-energizing the control element drive mechanism coils whenever any monitored condition reaches a trip setpoint. To meet the design requirements for redundancy and reliability for each measured variable, more than one, and often as many as four channels are used. In many cases, field sensors that input to the RPS are shared with the engineered safety features actuation system (ESFAS).

In response to the NRC staff's question whether any modification of the protection system is required for the SPU operations, the licensee stated that the IP2 existing instrumentation and control systems will continue to perform their intended safety functions under the SPU operations and that no modification on the protection system is required except for nominal trip setpoints and TS allowable value (AV) changes in some of the reactor trip and ESFAS functions to support SPU power level conditions. However, IP2 is also implementing a modification to the main steamline flow monitoring instrument channels. SPU analysis of the limiting hot full power (HFP) main steamline break (MSLB) event prompted a recommendation that the calibrated span of the main steam flow transmitters be increased from the current 4 million lbm/hr to 4.3 million lbm/hr. In conjunction with implementing this change, a qualified scaling module will be added to each of the eight flow measurement channels to ensure accurate tracking of the steam flow conditions under both normal and accident conditions. The NRC staff considers that this modification is for operational improvement and does not affect TSs or protection system configuration and therefore is acceptable.

3.1.2.2 Instrument Setpoints Methodology

By Amendment No. 238 dated November 21, 2003, IP2 implemented the Improved TSs (ITS). The instrument setpoint methodology was not specifically addressed during the ITS review. The setpoint methodology used to determine plant setpoints has recently come under increased scrutiny as it has been determined that one of the methods, Method 3, in Part II of ISA Standard S67.04 may not provide adequate margin between the safety analysis limit (SAL), or analytical limit (AL), and the allowable value (AV) as required by 10 CFR 50.36. Therefore, the NRC staff issued a request for additional information (RAI) to IP2 to verify that adequate margin exists between these two values.

The SPU proposed amendment reflects instrument setpoint changes consistent with a requested thermal power uprate for IP2 from 3114.4 MWt to 3216 MWt. In response to the staff's RAI on the instrument setpoint methodology, the licensee provided information and NRC clarifications by supplemental letter dated June 16, 2004. The setpoint methodology used to calculate trip setpoints and AVs of the plant parameters affected by the SPU is in accordance with Entergy Specification FIX-95-001, Revision 1, "Guidelines for Preparation of Instrument Loop Accuracy and Setpoint Determination Calculations," dated November 2001. The channel statistical allowance (channel uncertainty) of each instrument loop with AV changes in the power uprate was calculated using the Westinghouse methodology given in Appendix A of FIX-95-A-001. The alternate method described in Section 5.12.2 of FIX-95-A-001 was used. This method is similar to ISA-RP67.04 Part II, Method 3, with a modification. The check calculation is always required by this method.

FIX-95-A-001 Sections 5.12.1 and 5.12.2 states "Assure when jsquare root of (PMA^2 + PEA^2 + STE^2 + RTE^2 + SPE^2) + BIAS k are applied to Analytical Value, the calculated value does not infringe on the Allowable Value. If it does, add more conservatism to Allowable Value," where PMA = process measurement accuracy, PEA = process element accuracy, STE = sensor temperature accuracy, RTE = rack temperature accuracy, SPE = sensor pressure effects, and BIAS = biases, including environmental effects.

The licensee further stated that the check calculation is a combination of "non-calibration" errors that is applied in the direction of the setpoint from the analytical limit; this is the same as the AV calculation for Method 2. The AV calculations themselves contain an AV calculation by

Method 3 and by check calculation. In every case, the check calculation results have been more conservative, and the check calculation result has been chosen as the AV. Therefore, in practice, ISA-RP67.04, Part II, Method 2, has been applied to all AVs submitted for the IP2 power uprate for parameters with analytical limits. For IP2 SPU application, the check calculation has been included for AV determination.

The NRC staff finds that IP2 setpoint methodology used for the SPU is acceptable because the licensee demonstrated that there is sufficient margin between the AV and the analytical limit and that meets the requirements of 10 CFR 50.36 and RG 1.105.

3.1.2.3 I&C related TSs Changes Related to the Power Uprate

TS Table 3.3.1-1, “Reactor Protection System Instrumentation”

(1) Function 2.a, “Power Range Neutron Flux - High”

The “Power Range Neutron Flux - High” trip function is provided to protect against a positive reactivity excursion leading to departure from nucleate boiling (DNB) during power operations. Positive reactivity excursions can be caused by rod withdrawal or reductions in RCS temperature. For the SPU, the licensee proposed to change the AV from #112.6% RTP to #110.6% RTP, with the nominal trip setpoint (NTS) remaining unchanged at 109% RTP. The SAL of this trip function assumed in the SPU safety analysis is reduced from 118% RTP to 116% RTP to ensure the licensing basis acceptance criteria of the DNBR limit is met. In its letter dated June 16, 2004, the licensee replied to an RAI regarding the IP2 SPU. In Attachment II, Table 2, “NIS POWER RANGE NEUTRON FLUX - HIGH,” of this letter, the submittal provides a detailed calculation of the channel statistical allowance (CSA) and AV of this trip function. With the SAL and NTS of 116.0% and 109% RTP, respectively, the AV was calculated to be 110.6% RTP, which is consistent with the TS proposed value. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore is acceptable.

(2) Function 5, “Overtemperature ªT (OT ªT)”

The OT ªT trip function is provided to ensure that the design limit DNBR is met. The inputs to the OT ªT trip include reactor pressure, reactor coolant temperature, axial power distribution, and reactor power as indicated by loop ªT (assuming full reactor coolant flow) multiplied by a cycle-specific constant and other correction factors. The AV of the OT ªT function is specified as the percentage of the ªT span by which the channel maximum trip setpoint may exceed its computed trip setpoint. For the SPU, the licensee proposed to change from 3.3%ªT to 4.9%ªT span. Attachment II, Table 3, “Overtemperature ªT Reactor Trip,” of the June 16 letter provides the detailed calculation of the CSA and AV of this trip function. The calculation is consistent with the TS proposed value. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore is acceptable.

(3) Function 6, “Overpower ªT (OPªT)”

The OPªT trip function protects the integrity of the fuel under all possible overpower conditions. The trip setpoint is calculated by loop ªT (assuming full reactor coolant flow) multiplied by a cycle-specific constant and other correction factors. The AV of the OP ªT function is specified

as the percentage of the ªT span by which the channel maximum trip setpoint may exceed its computed trip setpoint. For the SPU, the licensee proposed to change from 2.3%ªT to 2.4% ªT span. Attachment II, Table 4, "Overpower ªT Reactor Trip," of the June 16 letter provides the detailed calculation of the CSA and AV of this trip function. The calculation is consistent with the TS proposed value. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105 and, therefore, is acceptable.

(4) Function 9, "Reactor Coolant Flow - Low"

The "Reactor Coolant Flow - Low" trip function is to protect against partial and complete loss of RCS flow that will violate the DNBR limit due to low flow in one or more RCS loops. For the SPU, the SAL and NTS remain at 85% and 92% flow, respectively. The licensee proposed to change the trip AV from $88.8% to $88.7%. Attachment II, Table 5, " Reactor Coolant Flow - Low," of the June 16 letter provides the detailed calculation of the CSA and AV of this trip function. The calculation is consistent with the TS proposed value. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore is acceptable.

(5) Function 13, "Steam Generator (SG) Water Level - Low-Low," and Function 14, "Steam Generator (SG) Water Level - Low"

These trip functions provide protection against loss of heat sink from the loss of normal feedwater transient. For the SPU, the SAL and NTS remain unchanged at 0% and 7% span, respectively. The licensee proposed to change the trip AV from 3.7% narrow range (NR) to 3.4% NR. Attachment II, Table 6, "Steam Generator Water Level - Low-Low," of the June 16 letter provides the detailed calculation of the CSA and AV of this trip function. The calculation is consistent with the TS proposed value. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore, is acceptable.

TS Table 3.3.2-1, "Engineered Safety Feature Actuation System Instrumentation"

(1) Function 1.f, "Safety Injection by High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low," and Function 4.d, "Steam Line Isolation by High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low"

These ESFAS functions initiate safety injection and steam line isolation for mitigation protection against the steamline break events. For the SPU, the AV for the T_{avg}-low setpoint is changed from $540.75 EF to $540.5 EF. In Footnote b associated with the AV high steam flow, the AVs are also changed from 53.7% to 45.9% full steam flow at or below 20% load, and from 110.8% to 122% full steam flow at 100% load. The licensee stated that the steamline break (SLB) protection logic actuation SALs are changed to enable a more timely actuation of the steam line isolation and safety injection. The T_{avg}-low SAL is assumed to be 537 EF, and the NTS is changed from 540 EF to 542 EF. The high steam flow SAL is changed from 74% to 64% full flow at or below 20% load, but the NTS remains unchanged at 40% full flow at or below 20% load, and 110% full flow at 100% load.

In Attachment II, Table 9, "T_{avg}-low," with the T_{avg}-low SAL of 537.0 EF, of the June 16 letter, the calculated AV is 539.1 EF. The proposed value of 540.5 EF is conservative. The NRC staff

finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore, is acceptable.

(2) Function 1.g, “Safety Injection by High Steam Flow in Two Steam Lines Coincident with Steam Line Pressure-Low,” and Function 4.e, “Steam Line Isolation by High Steam Flow in Two Steam Lines Coincident with Steamline Pressure-Low”

These ESFAS functions initiate safety injection and steamline isolation for mitigation protection against the steamline break events. For the SPU, the AV for the “Steam Line Pressure-Low” setpoint is changed from $426.0 psig to $540.3 psig. Attachment II, Table 8, “Steam Line Pressure - Low,” of the June 16 letter provided the detailed calculation of the CSA and AV of this trip function. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore, is acceptable.

(3) Function 5.b, “Feedwater Isolation by SG Water Level - High-High”

This ESFAS function provides protection against overfilling the SGs. For the SPU, the SAL for this function is being changed from 80% to 90% narrow range (NR) level due to potential increase in uncertainties associated with the SG level process. The licensee proposed to change the AV from #77.7% NR to #88.3% NR. Attachment II, Table 7, “Steam Generator Water Level - High,” of the June 16 letter provided a detailed calculation of the CSA and AV of this trip function. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore, is acceptable.

(4) Function 6.b, “Auxiliary Feedwater Actuation by SG Water Level Low-Low”

This ESFAS function provides protection against loss of normal feedwater. The licensee proposed to change AV setpoint from $3.7% narrow range to $3.4% NR. Attachment II, Table 6, “Steam Generator Water Level -Low-Low,” of the June 16 letter provided a detailed calculation of the CSA and AV of this trip function. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and RG 1.105, and therefore, is acceptable.

3.1.2.4 GDC Compliance

Because the IP2 construction permit was issued prior to the May 21, 1971, effective date of the GDC, compliance to these criteria is not required as part of the IP2 licensing basis. Although IP2 was not required to meet the GDC, the licensee has completed a study of compliance with 10 CFR Parts 20 and 50 in accordance with the Commission’s Confirmatory Order of February 11, 1980. The detailed results of the evaluation of IP2 compliance with the current GDC established by the NRC in 10 CFR Part 50, Appendix A, were submitted to the NRC on August 11, 1980. Commission concurrence was issued on January 19, 1982.

3.1.3 Summary

Based on the review of the IP2 SPU submittals, the NRC staff finds that the IP2 instrumentation and control systems will continue to perform their intended functions as required by plant license which complies with the NRC’s acceptance criteria related to the quality of design of protection and control systems that are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and

meet the intent of the GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. The NRC staff concludes that the licensee's instrument setpoint methodology for the proposed power uprate is consistent with the IP2 licensing basis and 10 CFR 50.36(c)(1)(ii)(A) and, therefore, is acceptable.

3.2 Reactor Systems

3.2.1 Regulatory Evaluation

The NRC staff reviewed the licensee's evaluations and analyses supporting a 3216 MWt SPU. The staff performed its review in accordance with the Review Standard for Extended Power Uprates, including the following areas: nuclear and fuel design; thermal-hydraulic design; systems evaluations; and LOCA and non-LOCA transient and accident analyses. Each of the review areas addressing the LOCA and non-LOCA transient and accident analyses is evaluated separately in the respective safety evaluation (SE) sections. Each of these sections describes the applicable regulatory requirements and acceptance criteria, the licensee's analyses or evaluations, and the NRC staff's conclusions. A detailed discussion about the codes and methodologies used in the SPU application can be found in Section 3.2.12.2 of this SE. The NRC staff also used NUREG-0800 in performing its review (Reference 24).

Section 1.3 of IP2's Updated Final Safety Analysis Report (Reference 11) lists the applicable regulatory requirements based on the GDC proposed in 1967 to which the plant was licensed.[1]

3.2.2 Technical Evaluation

3.2.2.1 Nuclear Steam Supply System (NSSS) Parameters

The NSSS design parameters provide the RCS and secondary system conditions for use in NSSS analyses and evaluations. The licensee provided a list of key plant parameters corresponding to the proposed SPU level of 3216 MWt in Table 2.1-2 of its application report (WCAP-16157-P). The major parameters include reactor power level, NSSS power level, thermal design flow, reactor coolant pressure and temperatures, steam generator pressure, steam temperature and steam flow rate. The major changes of these design parameters from the current values include increased core power level, decrease in the core inlet temperature, lower maximum steam pressure, lower maximum steam temperature, and a higher steam flow rate. These parameters are used in the licensee' s safety analyses performed to support its proposed power uprate, which resulted in acceptable margin to safety analysis limits. The NRC staff evaluated these changes and found them to adequately represent the plant operating

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[1]The GDC tabulated explicitly in the pertinent system sections, comprised the proposed Atomic Industrial Forum versions of the criteria issued for comment by the Atomic Energy Comission on July 11, 1967. Most recently, Consolidated Edison of New York (the former licensee) completed a study of compliance with the 10 CFR Parts 20 and 50 in accordance with the Commission's Confirmatory Order of February 11, 1980. The detailed results of the evaluation of Indian Point 2 compliance with the current GDC established by the NRC in 10 CFR Part 50, Appendix A, were submitted to the NRC by Consolidated Edison on August 11, 1980. Commission concurrence was received on January 19, 1982.

conditions at the proposed core power level of 3216 MWt. Therefore, the NRC staff finds the NSSS design parameters acceptable.

3.2.2.2 Reactor Coolant System

The changes in NSSS design parameters that impact the RCS design basis functions include the increase in core power and decrease in core inlet temperature. The minimum measured flow (MMF) stated in the COLR/TSs increased from 330,000 gallons per minute (gpm) to 348,300 gpm. The thermal design flow (TDF) of 80,700 gpm per loop, steady-state RCS pressure (2235 psig), and no load RCS temperature (547 EF) have not changed. The RCS temperature associated with the proposed SPU remains within the bounds of the original design temperature of 650 EF for the RCS and 680 EF for the pressurizer for the system. Sufficient core cooling under power uprate conditions is verified by various plant transient and safety analyses. The NRC staff finds that the changes of RCS operating parameters associated with the power uprate are acceptable based on the results of the safety analyses addressed in Section 3.2.2.12 below.

3.2.2.3 Safety Injection System (SIS)

The licensee verified the adequacy of the SIS during the injection and sump recirculation phases following a LOCA, in the LOCA analysis performed at a core power level of 3216 MWt. For the non-LOCA events, the performance of SIS was also verified by various safety analyses performed in support of the proposed power uprate. The licensee concluded that no system modifications are required to support the proposed SPU. The NRC staff agrees with the licensee's assessment based on the acceptable results of the safety analyses addressed in Section 3.2.2.12 below.

3.2.2.4 Residual Heat Removal (RHR) System

Operation at a higher power level increases the amount of decay heat being generated in the core, which results in a higher heat load to the RHR system for plant cooldown. As per the alternative shutdown capability requirements in 10 CFR Part 50, Appendix R, there is a 72-hour cooldown time to achieve cold shutdown conditions (Reference 28). For the cases run under SPU conditions, the licensee's calculation time increased from 70.9 to 71.9 hours, confirming that the RHR cooldown capacity meets the regulatory requirement. Based on this evaluation, the licensee concluded that system modifications are not required to accommodate the SPU. The NRC staff reviewed the licensee's evaluation and agrees with the licensee's assessment.

3.2.2.5 NSSS Transients

In its power uprate application report, the licensee evaluated the NSSS design transients to account for any power uprate impacts. The NSSS design transients are traditionally developed for stress analyses of the various NSSS components using conservative assumptions. The licensee provided a tabulation comparing the plant operating conditions at the current power rating and the proposed NSSS power level of 3216 MWt. The licensee compared the design parameters used in the existing design transients and for the SPU parameters and concluded that the existing design transients remain bounding and applicable for the SPU. Even though the existing design transients bound the SPU program, all of the design transients were re-

analyzed based on the SPU program design parameters to show the regulatory requirements are still met.

3.2.2.6 Fuel System Design Evaluation

The fuel system consists of fuel rods, spacer grids, guide thimbles, top and bottom end plates, and reactivity control rods including burnable poison rods. The NRC staff reviews the fuel system to ensure that the fuel system is not damaged as a result of normal operation and anticipated operational occurrences, that fuel system damage is never so severe as to prevent control rod insertion when it is required, the number of fuel rod failures is not underestimated for postulated accidents, and that core coolability is always maintained. The staff's review covers fuel system damage mechanisms, failure mechanisms, and safety of the fuel system during normal operation, anticipated operational occurrences, and postulated accidents. The NRC's acceptance criteria are based on the following: 10 CFR 50.46 for core cooling; assuring that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including anticipated operational occurrences; the reactivity control system being designed with appropriate margin, and in conjunction with the emergency core cooling system (ECCS), being capable of controlling reactivity and cooling the core under post-accident conditions; and for providing an ECCS to transfer heat from the reactor core following any loss of reactor coolant. Specific review criteria are contained in SRP Section 4.2

The NRC staff reviewed the licensee's analyses for the fuel design under SPU conditions. Rod internal pressure is considered a driving force for fuel system damage that could contribute to the loss of dimensional stability and cladding integrity. The NRC staff previously approved in WCAP-8963-P-A, a rod pressure limit that can exceed the system pressure provided that the fuel to cladding gap remains closed, i.e., no clad lift-off for Westinghouse fuel designs (Reference 45). The rod internal pressure will increase during SPU conditions. The licensee performed a bounding analysis using the approved fuel performance code PAD 4.0 for use at IP2 (Reference 37). The results showed that the maximum predicted rod pressure was below the critical pressure limit of no clad lift-off. Based on the results of the approved methodology, the NRC staff finds that the rod internal pressure analysis is acceptable for IP2 under SPU conditions.

SRP Section 4.2 identifies cladding oxidation buildup as a potential damage mechanism for fuel designs. The SRP further states that the effect of cladding oxidation needs to be addressed in safety and design analyses such as in the thermal and mechanical analysis. Recently the NRC staff determined that, in order to maintain adequate cladding ductility at high burnups, the total amount of oxidation or corrosion should be limited during normal operations including AOOs. The licensee established a corrosion limit and a hydriding pickup limit which could enhance corrosion. These limits were described in the approved PAD 4.0 code. The cladding corrosion will potentially increase during SPU conditions. The licensee performed a bounding analysis which showed that the maximum corrosion and hydriding were within the established limits under SPU conditions. Based on the acceptable results, the NRC staff concludes that the impact of corrosion on the thermal and mechanical performance will be minimal for IP2 under SPU conditions. The fuel rod strain fatigue capability could be impacted by SPU conditions of higher operating temperature and longer cycle length. The approved analysis of strain fatigue is based on the O'Donnell and Langer curve as described in the SRP Section 4.2. The licensee re-analyzed the strain fatigue capability under SPU conditions using the O'Donnell and Langer curve. The result showed that the fuel system design maintained its strain fatigue capability.

Based on the approved analysis, the NRC staff concludes that the strain fatigue capability is acceptable for IP2 under SPU conditions. The SRP Section 4.2 states that the stress and strain limits in fuel designs should not be exceeded for normal operations and AOOs. During SPU conditions, the fuel system could experience high power duty loading, thereby exceeding the stress and strain limits, for certain AOOs. The licensee re-examined the fuel system loading using the previously approved ANC code for use at IP2 as listed in UFSAR Section 3.2.1.3 for power histories and the PAD 4.0 code for fuel performance to analyze the stress and strain conditions. The results showed that the stress and strain limits were not exceeded for SPU conditions. Based on the approved analyses, the NRC staff concludes that the fuel system design meets the stress and strain limits for IP2 under SPU conditions.

Earthquakes and postulated pipe breaks in the RCS would result in external forces on fuel assemblies. Appendix A to SRP Section 4.2 states that fuel system coolability should be maintained and damage should not be so severe as to prevent control rod insertion when required during seismic and LOCA events. Fuel assemblies are analyzed for structural components, mainly grid spacers, to ensure that external forces do not exceed the maximum allowable grid crushing load such that the resulting damage is minimal, and control rods and thimble tubes remain functional during seismic and LOCA events. For the IP2 SPU operations, the worst scenario of seismic and LOCA events is the combination of different fuel types in the core. The licensee analyzed a mixed core of 15x15 upgrade fuel and the current resident fuel of 15x15 VANTAGE+ using the approved methodology described in WCAP-9401-P-A (Reference 6). The licensee selected two limiting mixed core configurations. The licensee used the square-root-of-sum-of-squares (SRSS) method, as described in the Appendix A to SRP Section 4.2, to combine the maximum LOCA and seismic impact forces. The results showed that the combined impact forces on grids in different elevations were all below the maximum allowable grid crushing load. Thus, the licensee concluded that there was no grid deformation and the coolable geometry was maintained under the seismic and LOCA events. Based on the approved methodology and the SRSS method, the NRC staff concludes that the grid impact analysis is acceptable and the coolable geometry will be maintained during the seismic and LOCA events for IP2 under SPU conditions.

The NRC staff reviewed the licensee's analyses related to the effects of the proposed SPU on the fuel system design. The staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the fuel system and demonstrated that: the fuel system will not be damaged as a result of normal operation and anticipated operational occurrences; the fuel system damage will never be so severe as to prevent control rod insertion when it is required; the number of fuel rod failures will not be underestimated for postulated accidents; and coolability will always be maintained. Based on this, the staff concludes that the fuel system and associated analyses will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the fuel system design.

3.2.2.7 Nuclear Design Evaluation

The NRC staff reviews the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the reactor coolant pressure boundary (RCPB) or impair the capability to cool the core. The staff's review covers core power distribution, reactivity

coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worth, criticality, burn-up, and vessel irradiation. The NRC's acceptance criteria are based on: (1) assuring that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including anticipated operational occurrences; (2) assuring that the prompt inherent nuclear feedback characteristics compensate for a rapid increase in reactivity; (3) assuring that the system is designed to preclude or detect and suppress power oscillations which could result in conditions exceeding specified acceptable fuel design limits; (4) assuring instrumentation and controls are available to monitor variables and systems affecting the fission process over anticipated ranges and maintaining the variables and systems within prescribed operating ranges; (5) assuring automatic initiation of the reactivity control systems to assure that acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and assuring automatic operation of systems and components important to safety under accident conditions; (6) assuring a single malfunction of the reactivity control system does not cause a violation of the specified acceptable fuel design limits; (7) assuring two independent reactivity control systems of different design, and each system having the capability to control the rate of reactivity changes resulting from planned, normal power changes are provided; (8) assuring the reactivity control systems in conjunction with poison addition by the ECCS, reliably control reactivity changes under postulated accident conditions, with appropriate margin for stuck rods; and (9) assuring the effects of postulated reactivity accidents neither resulting in damage to the RCPB greater than limited local yielding, nor causing sufficient damage to impair significantly the capability to cool the core. Specific review criteria are contained in SRP Section 4.3.

The NRC staff reviewed the licensee's analysis related to the nuclear design at the SPU of 3216 MWt. The licensee used the Westinghouse PHOENIX-P and ANC approved models to evaluate the nuclear design of the VANTAGE 15 x15 upgraded fuel design. The licensee modeled conceptual core loading patterns to be representative of future IP2 cores. The licensee demonstrated the results of key safety parameters listed in Table 7.3-1 of WCAP-16157 did not deviate markedly from the core design at current operating conditions. The licensee concluded the effect of the SPU on peaking factors, rod worths, reactivity coefficients, shutdown margin, and kinetics parameters will be well within normal cycle-to-cycle variation of these values or controlled by the core design, and will be addressed on a cycle-specific basis, consistent with the reload safety evaluation methodology (Reference 46). As a result, the ranges of key safety parameters as reported in Table 7.3-1 remain valid and bounding for the SPU.

The NRC staff reviewed the licensee's analysis related to the effect of the proposed SPU on the nuclear design. The staff concludes that the licensee adequately accounted for the effects of the proposed stretch power uprate on the nuclear design and has demonstrated that the fuel design limits will not be exceeded, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation, and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the regulatory requirements stated above following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the nuclear design.

3.2.2.8 Thermal and Hydraulic Design Evaluation

The NRC staff reviews the thermal and hydraulic design of the core and the RCS to confirm that the design has been established using acceptable analytical methods, is equivalent to or a justified extrapolation from proven designs, provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and anticipated operational occurrences, and is not susceptible to thermal-hydraulic instability. The acceptance criteria are based on the requirement that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded. Specific review criteria are contained in SRP Section 4.4.

Departure from nucleate boiling ratio (DNBR) re-analysis was required to define new core limits, axial offset limits, and Condition II accident acceptability to support the operation of IP2 at SPU conditions. The thermal-hydraulic design criteria and methods for the SPU remained the same as those presented in the IP2 UFSAR, and are therefore approved by NRC for use at IP2. The DNBR analysis assumed that the SPU core design is composed of 15x15 VANTAGE+ and 15x15 upgraded fuel assemblies. The licensee used the Westinghouse version of the VIPRE code for DNBR calculations with the WRB-1 and the W-3 DNB correlations. The licensee performed its safety analyses to DNBR limits higher than the design limit DNBR values. In its response to a staff RAI, the licensee provided the numerical values calculated for the design limit DNBR, safety analysis limit DNBR, DNBR margin, and DNBR penalties for a mixed core. The results showed sufficient DNBR margin was maintained in the safety analysis DNBR limits to offset the rod bow, transition core, and plant operating parameter bias DNBR penalties under SPU conditions. Therefore, the licensee did not exceed the specified fuel design limits.

The NRC staff reviewed the licensee's analysis related to the effects of the proposed SPU on the thermal and hydraulic design of the core and the RCS. The staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the thermal and hydraulic design and demonstrated that the design has been established using acceptable analytical methods, is equivalent to proven designs, provides acceptable margins of safety from conditions which could lead to fuel damage during normal reactor operation and anticipated operational occurrences, and is not susceptible to thermal-hydraulic instability. The staff concludes that the thermal and hydraulic design will continue to meet the acceptance criteria following implementation of the proposed stretch power uprate. Therefore, the NRC staff finds the proposed stretch power uprate acceptable with respect to thermal and hydraulic design.

3.2.2.9 Functional Design of Control Rod Drive System

The NRC staff's review covers the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during anticipated operational occurrences, and prevent or mitigate the consequences of postulated accidents. The acceptance criteria are based on proper rod insertion, withdrawal, and scram operation times. Specific review criteria are contained in SRP Section 4.6.

The NRC staff reviewed the licensee's analysis related to the rod cluster control assembly (RCCA) insertion at the SPU of 3216 MWt. The licensee performed a drop time analysis in which the licensee obtained actual plant drop time-to-dashpot entry data at no flow and full flow conditions for each RCCA location. The components affecting drop time were the fuel, upper core plate, upper and lower guide tubes, upper support plate, reactor closure head penetration,

thermal sleeve, CRDM, rod travel housing, and the RCCA/drive rod assembly. The system operating conditions included temperature, pressure, and flow derived from the use of the THRIVE code. The licensee used the Westinghouse developed DROP algorithm with the analytical model to correlate the model to the plant measured drop times, taking into account the new system operating conditions due to the SPU. The licensee calculated the maximum RCCA drop time with seismic allowance to be 1.8 seconds, which satisfies the IP2 TS limit of 2.4 seconds. The NRC staff finds the RCCA drop time is acceptable since the time is bounded by the TS limit.

The NRC staff reviewed the licensee's analysis related to the effects of the proposed SPU on the functional design of the CRDS. The staff concludes that the licensee demonstrated that the system continues to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents following the implementation of the proposed stretch power uprate. Therefore, the NRC staff finds the proposed stretch power uprate acceptable with respect to the functional design of the CRDS.

3.2.2.10 Overpressure Protection During Power Operation

Overpressure protection for the reactor coolant pressure boundary (RCPB) during power operation is provided by relief and safety valves and the RPS. The acceptance criteria are based on the RCS and associated auxiliary, control, and protection systems being designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded, and the RCPB being designed with sufficient margin to assure that it behaves in a nonbrittle manner while minimizing the probability of rapidly propagating fracture. Specific review criteria are contained in SRP Section 5.2.2.

The licensee analyzed a 10% step load decrease from full power using the LOFTRAN code (Reference 43). The results of this analysis showed no reactor trip setpoints were challenged and the control system response was stable and non-oscillatory. The licensee also analyzed a 10% step load increase from 90% power using the LOFTRAN code. The licensee stated in its response to a staff RAI, that IP2 defeated automatic rod withdrawal a few years back to prevent spurious withdrawal of the rods, which could cause flux variations and decreasing average temperature, thus precluding the possibility of an inadvertent reactivity excursion event (Reference 16). Therefore, this action was not credited in this transient. Operator action is credited for manually withdrawing rods in order to increase reactor power in response to the turbine load increase. The licensee analyzed plant response during the 10% step load increase transient and found that the transient can be accommodated successfully without challenging any reactor trip or ESFAS setpoint. Additionally, the licensee analyzed the plant response to a 50% load rejection from full power. The results showed the control system response was smooth and peak pressurizer pressure was controlled by the pressurizer power operated relief valve (PORV) actuation, preventing the pressurizer pressure from reaching the high pressurizer pressure reactor trip setpoint. The licensee concluded the control systems were stable and support the SPU for all normal condition transients. In its response to a staff's RAI with respect to overpressure protection during power operation, the licensee stated that WCAP-7769 (Reference 41) originally justified the RCS and MSSV capacities for IP2 relative to the overpressure acceptance criterion and the licensee confirmed that the methodology is still applicable under SPU conditions. The SPU analysis confirmed that when modeling the pressurizer safety valve (PSV) capacity of 408,000 lbm/hr/valve for each of the three PSVs at IP2, the RCS overpressure criterion was met.

The NRC staff reviewed the licensee's analysis related to the effects of the proposed SPU on the overpressure protection capability of the plant during power operation. The staff concludes that the licensee adequately accounted for the effects of the proposed power uprate on pressurization events and overpressure protection features. The staff finds the licensee adequately demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. The staff concludes that the overpressure protection features will continue to provide adequate protection to meet the regulatory requirements at an uprated power of 3216 MWt. Therefore, the NRC staff finds the proposed stretch power uprate acceptable with respect to overpressure protection during power operation.

3.2.2.11 Overpressure Protection During Low Temperature Operation

WCAP-15629 (Reference 43) describes the vessel fluence calculations for 25 effective full-power years (EFPYs) of operation at 3216 MWt starting with cycle 16. The DOT code was used with ENDF/B-VI cross sections, a P_5 inelastic scattering approximation and a S_{16} order of angular quadrature. In addition, it is stated in WCAP-15629 (Reference 38) that the fluence calculation followed the guidance in Draft Guide (DG) 1035, which is considered as equivalent to RG 1.190, and therefore, the NRC staff finds the vessel fluence calculations acceptable.

The NRC issued Amendment No. 224 for IP2, on February 15, 2002, which approved the fluence calculations, the corresponding pressure temperature (PT) curves for 25 EFPYs (at 3216 MWt), and the pressurized thermal shock (PTS) evaluation for 32 EFPYs at 3216 MWt. Therefore, the requested PT curves for 25 EFPYs and PTS evaluation for 32 EFPYs (both for 3216 MWt) have already been approved by the NRC staff and are acceptable for the proposed power uprate. The power uprate does not affect the Appendix G related material properties. The NRC staff agrees the current low temperature overpressure protection limit setting will be valid as long as the fluence value remains below the value used in the calculation of the current limits.

3.2.2.12 Transient and Accident Analyses

The licensee re-analyzed the UFSAR Chapter 14 LOCA and non-LOCA transients and accidents in support of the IP2 SPU. These analyses were performed at a rated core power of 3216 MWt using plant parameter values for those operating conditions. The initial condition uncertainties were recalculated at power uprate conditions for use in the IP2 SPU program. These uncertainty calculations were performed for the uprate operating conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures. The methodology used for the IP2 SPU program uncertainty calculation was previously approved in the recent 1.4 percent measurement uncertainty recapture power uprate (Reference 39). The NRC staff reviewed the licensee's transient and accident analyses at the 3216 MWt SPU conditions to verify the acceptance criteria are still met under these conditions. The staff's review of the UFSAR LOCA and Non-LOCA transients and accidents is discussed in the following sections.

3.2.2.12.1 LOCA Analyses

By letter dated January 29, 2004, as supplemented by letters dated April 12, July 2, August 3, and August 12, 2004, the licensee referred to the present IP2 large-break LOCA (LBLOCA) and

small-break LOCA (SBLOCA) analyses performed in 1997 at the uprated power for 15x15 Westinghouse (W) Vantage+ (ZIRLO-clad fuel) assemblies. These letters also address LBLOCA and SBLOCA analyses for mixed cores with upgraded 15x15 W Vantage+ fuel assemblies, and the present W 15x15 Vantage+ fuel assemblies that will be implemented at IP2. The licensee provided the LBLOCA and SBLOCA analyses results for the W upgraded Vantage+ fuel, and provided updated results in Reference 14. The LBLOCA results are based on a reassessment (per 10 CFR 50.46(a)(3)) based on the 1997 LBLOCA analyses performed with the IP2 plant-specific W LBLOCA methodology described in WCAP-12945, and with adjustments to account for changes and errors in the 1997 analyses, and mixed cores (Reference 23 and Reference 4). The SBLOCA analyses' results were explicitly recalculated using the W LBLOCA methodology described in the W NORTRUMP (COSI) SBLOCA methodology (Reference 30). The NRC staff reviewed these analyses to assure that the licensee met the requirements of 10 CFR 50.46(b).

By letter dated January 29, 2004, the licensee provided the LOCA plant-specific analyses results for the upgraded W Vantage+ fuel. The licensee provided amended LOCA results for the W Vanatage + fuel in its July 2, 2004, letter. The following provides the licensee's LBLOCA analysis results.

LBLOCA

Limiting break Size/location	LBLOCA	LBLOCA
Fuel Type	W 15x15 fuel	W Vantage+ fuel with ZIRLO
Peak Clad Temperature (PCT)	2115 °F*	2137 °F
Maximum Local Oxidation	13.2%**	13.2%**
Maximum Total Core-wide Hydrogen Generation (All Fuel)	(0.94%)**	(<<0.071%) **

* The PCT results reported in the August 12, 2004, letter are for one fuel only values. The PCT values given in the table are based on the apparent mixed-core penalty derived from information in the January 29, 2004, application, which did consider mixed core effects.
** These LBLOCA local oxidation and core-wide hydrogen generation values are from the August 12, 2004, letter, and are bounding values used for both fuels. The local oxidation value includes pre-LOCA oxidation. The licensee states that operational controls are such that the total oxidation will always be below 15%.

The licensee provided the plant-specific SBLOCA analyses for IP2 in Reference 14 and Reference 19. The licensee performed the analyses using the Westinghouse NOTRUMP (with COSI) SBLOCA methodology. The following table provides the licensee's SBLOCA analysis results.

SBLOCA

Limiting Break Size/Location	3-inch Pump Discharge	3-inch Pump Discharge
Fuel Type	W 15x15 fuel	W Vantage+ fuel with ZIRLO
PCT	1028 °F	1028 °F
Maximum Local Oxidation	0.02%	0.02%
Maximum Total Core-wide Oxidation (All Fuel)	<<1.0%	<<1.0%

The licensee did not provide separate results for each fuel type. Also, the licensee did not report "total" oxidation and hydrogen generation values for SBLOCA. However, because the estimated PCT is so low, it is reasonable to assume that cross flow has a negligible effect on PCT, oxidation, and core-wide hydrogen generation since the core is receiving adequate flow to keep fuel temperatures down.

These calculated values given in the tables above are less than the limits specified in 10 CFR 50.46(b)(1) to 10 CFR 50.46(b)(3), which requires the PCT to be less than 2200 EF, the maximum cladding oxidation to be less than 17%, and the maximum hydrogen generation to be less than 1.0 percent. As a result, the licensee has demonstrated compliance with 10 CFR 50.46(b)(1) to 10 CFR 50.46(b)(3). Additionally, the licensee, as discussed below, demonstrated compliance with 10 CFR 50.46(b)(5). In as much as no other consideration affects the IP2 core geometry, this assures that the IP2 core will remain amenable to cooling as required by 10 CFR 50.46(b)(4).

In summary, the NRC staff concludes that the licensee's LOCA analyses were performed with LOCA methodologies that apply to IP2, and demonstrate that IP2 complies with the requirements of 10 CFR 50.46(b)(1)-(5). Therefore, the NRC staff finds the licensee's LOCA analyses acceptable.

3.2.2.12.1.1 Mixed Core LOCA Analyses

As discussed above, the licensee's LBLOCA and SBLOCA analyses acceptably address the differences between the W Vantage+ fuel which has been used for IP2, and the upgraded W Vantage+ fuel with ZIRLO cladding which will be introduced with the IP2 power uprate.

3.2.2.12.1.2 Overall Applicability of LOCA Analysis Methodologies

The W LBLOCA methodology described in WCAP-12945 specifically applies to IP2, because the plant-specific version of the WCAP-12945 methodology used for the IP2 analyses in 1997 and LBLOCA analyses for IP2 have not changed since they were approved in an NRC SE dated March 31, 1997. The IP2 plant-specific version of the W LBLOCA methodology described in WCAP-12945 is a version that predates the generic approval of the methodology, and does not contain all of the technical features of the generically approved methodology. The NRC staff's review of the IP2-specific version included the IP2-specific LBLOCA analysis, which

verified that the features missing from the IP2 specific methodology version would not have affected the calculated results. The staff's March 31, 1997, SE gave a one-time analysis-specific approval of the IP2 version of the methodology and the analyses and were performed for the proposed uprate power at the time. The 1997 LBLOCA analyses results have been updated in accordance with 10 CFR 50.46(a)(3), and the licensee, in a letter dated July 2, 2004, has proposed to schedule LBLOCA reanalyses for April 29, 2005, in accordance with 10 CFR 50.46(a)(3)(ii).

In a letter dated September 24, 2004, the licensee stated that IP2 and its vendor have ongoing processes which assure that the LOCA input parameters' ranges and values for IP2 LOCA analyses conservatively bound the ranges and values of those parameters for the as-operated IP2 plant.

These LOCA methodologies apply to plants of Westinghouse design and Westinghouse fuels, and have no technical limitations which would preclude their use for the proposed IP2 power uprate. Further, the licensee's statement above provides the assurance that the analyses results obtained using those LOCA methodologies will continue to apply to IP2. The NRC staff concludes that W LOCA methodologies identified above apply to IP2 which is a Westinghouse-designed plant that uses Westinghouse fuel.

3.2.2.12.1.3 Slot Breaks at the Top and Side of the Pipe

The NRC staff requested that the licensee address slot breaks at the top and side of a reactor pump discharge cold leg pipe, which could, under some circumstances, lead to greatly extended periods of core uncovery, resulting in fuel cladding oxidation in excess of the 10 CFR 50.46 (b)(2) limit, and also possibly in excess of the total hydrogen limit of 10 CFR 50.46 (b)(3). In Reference 19, the licensee discussed information which is included in a generic W report written to address this issue. In its response to a staff RAI, the licensee stated that the Emergency Operating Procedures (EOPs) at IP2 were based on approved Westinghouse Owners Group (WOG) EOP guidelines and direct timely operator actions that would avoid the conditions for extended core uncovery. In Reference 19, the licensee indicated that the operator procedures and actions would be effective in LBLOCA scenarios because extended core uncovery would take a significant amount of time to develop. The licensee has concluded that the existing provisions continue to apply to the upcoming cycle of operation, because the extended core uncovery issue of concern is fuel-independent.

Based on its review of the information provided by the licensee, and as set forth above, the NRC staff concludes that the licensee's analysis has successfully addressed this issue. The resolution of this issue applies to the current IP2 licensing basis and does not resolve the generic issue of slot breaks at the top and side of the pipe for any vendor methodology.

3.2.2.12.1.4 Downcomer Boiling

By letter dated August 12, 2004, the licensee provided the results of an analysis it had performed using the approved W best-estimate LBLOCA methodology that demonstrate that following a LBLOCA, IP2 would attain a stable and sustained core quench. This indicates that at IP2 downcomer boiling would not occur to the extent that it would significantly degrade core cooling in the first 1600 seconds of a LBLOCA transient. Therefore, the NRC staff finds this acceptable. The NRC staff is presently pursuing concerns related to downcomer boiling in a

generic matter. If that review raises any concerns applicable to the LOCA analyses at IP2, then the NRC staff will request the licensee to address these issues consistent with any generic resolution.

3.2.2.12.1.5 Post LOCA Long-Term Cooling (LTC)

The regulatory requirement for LTC is provided in 10 CFR 50.46(b)(5) which states "After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core." Although the SRP, (NUREG-0800) provides some guidance, it essentially repeats the regulatory requirement. In practice, following successful calculated blowdown, refill, and reflood after initiation of a LOCA, the LTC requirement will be met if the fuel cladding remains in contact with water so that the fuel cladding temperature remains essentially at or below the temperature where boiling occurs. A potential challenge to long-term cooling is that boric acid (H_3BO_3) could accumulate within the reactor pressure vessel (RPV), precipitate, and block coolant flow needed to keep the fuel cladding wetted by water. Consequently, the NRC staff reviewed the licensee's approach to control H_3BO_3 during LTC.

The concern arises if a LOCA results in loss of water circulation through the core, which may occur with a large cold leg break where ECCS water maintains water level above the bottom of the cold leg and no water leaves the RV via the hot legs due to the elevation of the flow path through the SG tubes. This results in boiling in the core, which provides core cooling, with steam leaving via the hot legs and passing through the SGs and out the break in the cold leg. Core water inventory removed by boiling is replenished via the downcomer due to the maintained cold leg water level. However, the incoming water contains H_3BO_3 and, since H_3BO_3 is not considered to be removed by the steam, H_3BO_3 will continue to concentrate in the core. Eventually, H_3BO_3 may begin to precipitate and could potentially block the flow of water needed to cool the fuel rods, raising the question of meeting the requirements of 10 CFR 50.46(b)(5). This condition is prevented by initiating injection of water into the hot legs at a rate greater than the boiloff rate so that water is forced into the lower plenum, up the downcomer, and out the cold leg break, thus preventing further increase in the H_3BO_3 concentration and preventing H_3BO_3 precipitation.

The licensee reported that it analyzed this H_3BO_3 process using a variation of a model that was described in Reference 5. This analysis of H_3BO_3 behavior was previously used for the Byron and Braidwood thermal power increase that was granted by the NRC staff via Reference 8. A further model variation to introduce conservatisms was described in Reference 12, with NRC staff approval, via Reference 7. The staff compared the licensee's description of its model with the Reference 24 model and found no significant differences. Thus, the NRC staff accepts the licensee's statement that "the methodology ... is consistent with, or otherwise conservative with respect to, the methodology described in" Reference 5.

These models are limited to describing behavior associated with a LBLOCA. They do not fully represent H_3BO_3 behavior during reflood following initiation of the LOCA, include consideration of potentially significant phenomena associated with transient or pseudo steady-state conditions, or address potential behavior during smaller break-size LOCAs where natural circulation may be lost and regained, including whether H_3BO_3 may participate when cooler water circulates into the core following an extended time when H_3BO_3 may have been

concentrating. Use of a model where such modeling considerations are not addressed is not unique to this licensee, and the NRC staff has previously questioned H_3BO_3 behavior modeling during long-term cooling when reviewing applications from other licensees. In these cases, the NRC staff has considered the low probability that conditions leading to significant H_3BO_3 accumulation will be encountered and that there are a number of modeling conservatisms that tend to compensate for modeling inadequacies[2]. Consequently, the NRC staff does not consider the outstanding issues to be a significant safety concern, and in the interim until generic concerns associated with LTC are resolved, the staff will rely on an interim evaluation of comparing LTC characteristics with cases where effective H_3BO_3 dilution action was initiated well before the staff judged the action was necessary.

This comparison is provided in the following table which compares information from References 25 and 13 to characteristics provided by the licensee:

Comparison of H_3BO_3 Accumulation Characteristics						
	Characteristic	Byron/ Braidwood 5% uprate	ANO-2 7.5% uprate	Palo Verde 2.94% uprate	Kewaunee 6% uprate (7.4% including previous uprate)	IP2 3.26% uprate
1	Time to reach H_3BO_3 saturation (hours).	8.53 (5/4/01) 6.0 (4/12/02)	~2.4 to 7.3, depending on assumptions	~3.5 (FSAR)	7.8	6.76 (rounded to 6.5)
2	Power (MWt).	3587	3026	4070	1772 + 0.6% uncertainty	3216
3	Decay heat generation rate multiplier (dimensionless).	1 (5/4/01) 1.2 (4/12/02)	1.1	1.1	1	1.2
4	Assumed H_3BO_3 saturation limit (wt%).	23.53	27.6	30	23.53	23.53

[2]The licensee provided some applicable information in Reference 19 where it stated “the reactor coolant system response following a LOCA is a dynamic process” in regard to plugging and unplugging of the reactor coolant pump suction leg U-bend following large and intermediate break LOCA. Such behavior, if fully substantiated, would induce a flushing action into the RV as RV level increased and decreased in response to plugging and unplugging of the U-bends and would tend to flush H_3BO_3 out of the core, although H_3BO_3 would accumulate more rapidly during those times where RV water level was decreased due to U-bend plugging.

Comparison of H_3BO_3 Accumulation Characteristics						
	Characteristic	Byron/ Braidwood 5% uprate	ANO-2 7.5% uprate	Palo Verde 2.94% uprate	Kewaunee 6% uprate (7.4% including previous uprate)	IP2 3.26% uprate
5	Core plus upper plenum volume below hot leg (ft^3).	1072*	940	Multiplying power by mixing volume ratio gives approximately ANO power	Power to volume ratio is similar between 2 and 4 loop Westinghouse plants	Same assumptions as used for Byron / Braidwood
6	Time to hot leg injection via emergency operating procedures (hours)	Consistent with Item 1 prediction	2 to 4	2 to 3	6.6	6.5 (Reference G)
*Value is from NUREG-1269, "Loss of Residual Heat Removal System, Diablo Canyon Nuclear Power Plant, Unit 2, April 10, 1987," June 1987.						

The NRC staff notes that Byron/Braidwood procedures would adequately ensure establishing effective hot leg injection in 6 hours whereas IP2 would establish it in 6.5 hours. However, an approximate adjustment for the different power level leads to (6)(3597)/3216 = 6.7 hrs, which agrees with the licensee's prediction.

Therefore, while the NRC staff cannot endorse the licensee's evaluation as a valid mechanistic model of the phenomena, the staff believes, on an interim basis, that there is sufficient basis to approve the license amendment with respect to LTC and potential H_3BO_3 precipitation concerns.

This NRC staff conditional acceptance will remain effective until generic concerns associated with LTC are rectified, at which time the licensee will have to establish that it is in compliance with the resolution of the generic concerns.

3.2.2.12.2 Non-LOCA Transients and Accidents

The licensee re-analyzed IP2's UFSAR Chapter 14 non-LOCA events at the stretch power uprate conditions of 3216 MWt. The NRC previously approved the computer codes and methodologies used in each of the non-LOCA transient analyses at IP2. The licensee used the RETRAN computer code in the IP2 non-LOCA SPU safety analyses, simulating a Westinghouse four-loop plant design, applicable to IP2, as described and presented in WCAP-14882-P-A (Reference 36). The licensee used RETRAN in combination with VIPRE-01 for reactor core subchannel thermal-hydraulic calculations, a neutronic code such as ANC, and a fuel performance code such as PAD 4.0 in core design, as described in References 35, 32, and 37, respectively. The licensee used TWINKLE, a multidimensional neutron computer code, in conjunction with FACTRAN, a code for thermal transients in a UO2 fuel rod, to perform the RCCA ejection and the uncontrolled RCCA withdrawal from a subcritical or low power startup condition analyses (References 44 and 42). The licensee met the conditions and restrictions set on the specific codes. Where applicable, the licensee used the previously approved

Revised Thermal Design Procedure (RTDP) methodology discussed in WCAP-11397-P-A (Reference 34) in performing the non-LOCA safety analyses. The NRC staff finds the codes and methodologies used by the licensee to perform the safety analyses under SPU conditions acceptable since the licensee satisfies the conditions and restrictions set on the specific codes for application at IP2.

3.2.2.12.2.1 Excessive Heat Removal Due to Feedwater System Malfunction

Excessive heat removal causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The acceptance criteria are based on critical heat flux not being exceeded, pressure in the RCS and main steam system (MSS) being maintained below the 110% of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Specific review criteria are contained in SRP Section 15.1.1-4.

The licensee used the RETRAN computer code to analyze the excessive heat removal due to a feedwater system malfunction. The VIPRE subchannel code calculated the hot channel heat flux transient and DNBR. The RPS provided mitigation for this event and the results showed RCS pressure remained below the 110% design value. The limiting case DNBR value remained above the safety analysis limit provided in Table 3-1 of the licensee's June 16 letter.

The NRC staff reviewed the licensee's analysis and concludes that the licensee operated using acceptable analytical models. The staff finds the licensee demonstrated that the reactor protection and safety systems will continue to ensure the following: critical heat flux will not be exceeded; pressure in the RCS and MSS will be maintained below 110 percent of the design pressures; and the peak linear heat generation rate will not exceed a value that would cause fuel centerline melting. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

3.2.2.12.2.2 Excessive Load Increase Incident

An excessive load increase incident is defined as a rapid increase in the steam flow that causes a power mismatch between the reactor core power and the SG load demand. The RCS is designed to accommodate a 10% step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100% of full power, taking credit for all controls systems in automatic. Any loading rate in excess of these values can cause a reactor trip actuated by the RPS. The acceptance criteria are based on critical heat flux not being exceeded, pressure in the RCS and MSS being maintained below the 110% of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt.

The licensee evaluated two cases which demonstrated that the fuel cladding integrity will not be adversely affected following a 10% step-load increase from rated load. One case was a manually controlled reactor with beginning of life (BOL) reactivity feedback, while the other case was a manually controlled reactor with end of life (EOL) reactivity feedback. The RPS was assumed to be operable. In performing its evaluation, the licensee used conservatively

bounding conditions in generating statepoints using the RTDP methodology, which are then compared directly to the IP2 SPU core limits. If the minimum DNBR statepoint conditions remain above the SPU safety analysis DNBR limit, no further analysis is required. The licensee evaluated the effect of this transient on the minimum DNBR by applying conservative deviations on the initial conditions for core power, vessel average temperature, and pressurizer pressure at the normal full power operating conditions in order to generate a limiting set of statepoints. The bounding deviations in plant parameters (proprietary) that were used in the evaluation of this transient were provided in Reference 16. These deviations bound the variations that could occur as a result of an excessive load increase accident and were only applied in the directions that have the most adverse impact on DNBR. The statepoints generated were compared to the IP2 SPU limiting DNB core limit lines that represent the limiting DNBR conditions for the uprate. The licensee found that when applying conservatively bounding conditions to the plant parameters for this event, the corresponding minimum DNBR statepoint conditions remained above the SPU DNBR safety analysis limit.

The NRC staff reviewed the licensee's evaluation of the excessive load increase incident and concludes that the licensee's analysis demonstrated the SPU DNBR safety analysis limit remains bounding for this event. The staff finds the licensee demonstrated that the reactor protection and safety systems will continue to ensure critical heat flux will not be exceeded, pressure in the RCS and MSS will be maintained below the 110% of the design pressures, and the peak linear heat generation rate will not exceed a value that would cause fuel centerline melt. The NRC staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU and finds the proposed power uprate acceptable with respect to the excessive load increase incident.

3.2.2.12.2.3 Steam Line Break (SLB)

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient. This event is an American National Standard (ANS) condition IV event (infrequent fault): fuel failure is expected, and the radiological dose criteria is addressed separately by the NRC staff.

In performing its analysis, the licensee assumed the most reactive RCCA stuck in its fully withdrawn position. The licensee reviewed two cases, one with offsite power available, and the other with loss of offsite power. The licensee used the RETRAN computer code to calculate the core heat flux and the RCS temperature and pressure resulting from the cooldown. The licensee performed the analysis using the VIPRE code to determine if DNBR fell below the safety analysis limit. The licensee performed the DNBR analysis for the most conservative case and found that the DNBR remained above the DNBR limit for this event under SPU conditions.

The NRC staff reviewed the licensee's analysis of the excessive heat removal due to SLB and concludes that the licensee's analysis was performed using acceptable analytical models. The NRC staff concludes the licensee met the DNB design-basis criterion and finds the proposed power uprate acceptable with respect to the SLB.

3.2.2.12.2.4 Loss of External Electric Load

A major loss of load can result from either a loss of external electrical load or from a turbine trip. These events result in a sudden reduction in steam flow and, consequently, pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit and pressure in the RCS and MSS remaining below 110% of the design values. Specific review criteria are contained in SRP Section 15.2.1-5.

The licensee re-analyzed the peak pressure case without pressure control and the minimum DNBR case with pressure control. In performing its analyses, the licensee assumed minimum reactivity feedback (at BOL) conditions, least negative doppler coefficients, and no credit for operation of the steam dump system or SG atmospheric valves, which maximizes secondary pressure. Additionally, the licensee assumed main feedwater flow was terminated at the time of the turbine trip, with no credit taken for AFW, except for long-term recovery to mitigate the consequences of the transient. The licensee used the Standard Thermal Design Procedure (STDP) methodology to analyze the peak pressure case without pressure control and the RTDP methodology to analyze the minimum DNBR case with pressure control. The licensee performed the analyses using the RETRAN computer code to determine the plant transient conditions following a total loss of load for both conditions. The peak pressure case did not take credit for the pressurizer spray, pressurizer PORVs, or for the steam dump. The reactor tripped on a high-pressurizer pressure trip signal. The pressurizer water-solid condition was precluded, thus uncompromising the RCS pressure boundary and preventing progression into another condition event. The results showed the primary system pressure remained below the 110% design value and the secondary side steam pressure below 110% of the SG shell design pressure. The minimum DNBR with pressure control case took credit for the pressurizer spray and pressurizer PORVs, but not the steam dump. The reactor tripped on a high pressurizer pressure reactor trip signal. The analysis results showed the minimum DNBR remained above its safety analysis limit.

The NRC staff reviewed the licensee's analyses of the loss of external electric load and concludes that the licensee's analyses were performed using acceptable analytical models. The staff finds that the licensee demonstrated that the minimum DNBR will remain above the safety analysis limit and pressure in the RCS and MSS will remain below 110% of the design values for the proposed power uprate. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the loss of external electric load.

3.2.2.12.2.5 Loss of AC Power to the Plant Auxiliaries

The licensee assumes the loss of non-emergency AC power results in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown, as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, pressure in the RCS and MSS being maintained below 110% of the design pressures, and an incident of

moderate frequency not generating a more serious plant condition without other faults occurring independently. Specific review criteria are contained in SRP Section 15.2.6.

The licensee concluded from its analysis that in a loss of AC (LOAC) power to the station auxiliaries, the plant response is almost identical to the complete loss-of-flow accident at IP2. After the trip, the AFW system removes decay heat and this portion of the transient is comparable to the loss of normal feedwater (LONF) event. The licensee also proposed to credit operator action within 10 minutes of the trip to start the second motor-driven AFW pump (MDAFWP) or align the turbine-driven AFW pump (TDAFWP). The NRC staff finds it acceptable to take credit for operator action in the LOAC event since the latter part of this transient parallels the LONF event and the staff finds the LONF analysis and proposed actions acceptable. The RETRAN code results showed that natural circulation and the AFW flow available were sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown. The results also showed the pressurizer did not reach a water-solid condition and the RCS and MSS pressures remained below the applicable design limits throughout the transient. The licensee stated the LOAC event was bounded by the complete loss-of-flow event since the first few seconds of the transient would be almost identical to the complete loss of flow, in which pump coastdown inertia along with the reactor trip prevents reaching the DNBR safety analysis limit. The licensee provided the justification for this statement in its June 16, 2004, letter.

The NRC staff reviewed the licensee's analysis of the loss of AC power to plant auxiliaries and concludes that the licensee's analysis was performed using an acceptable analytical model, as stated above. The staff finds the licensee demonstrated that the reactor protection and safety systems will continue to ensure that the specified fuel design limits are not exceeded, the peak primary and secondary system pressures are not exceeded, and a more serious plant condition is precluded. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the loss of AC power to the plant auxiliaries.

3.2.2.12.2.6 Loss of Normal Feedwater

A LONF flow could occur from pump failures, valve malfunctions, or losses of offsite power. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure, which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a LONF flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, pressure in the RCS and MSS being maintained below 110% of the design pressures, and an incident of moderate frequency not generating a more serious plant condition without other faults occurring independently. Specific review criteria are contained in SRP Section 15.2.7.

In performing its analysis, the licensee assumed the RCPs operated continuously throughout the transient providing a constant reactor coolant volumetric flow equal to the TDF. This is a conservative assumption in which additional heat is added to the system through the RCPs. The pressurizer spray, PORVs, and heaters were assumed to be operable to maximize the pressurizer water volume. This is a conservative assumption because if these control systems did not operate, the pressurizer safety valves would maintain peak RCS pressure at or below

the actuation setpoint throughout the transient. The reactor trip occurred on SG low-low water level, and automatic AFW flow was assumed to be initiated 60 seconds following a low-low SG water level signal. The worst single failure modeled in the analysis is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 380 gpm, distributed equally between 2 of the 4 SGs. Additional flow from the second MDAFWP or TDAFWP is assumed to be available only following operator action to start the second MDAFWP or to align the TDAFWP. The LONF event was re-analyzed at the SPU conditions using the RETRAN computer code. In the application, the licensee requested approval to credit the operator action to start the second MDAFWP or to align the TDAFWP at 10 minutes after reactor trip on a SG low-low water level signal to provide additional AFW flow to the SGs not fed by the AFW pumps assumed to start on the low-low SG water level signal for the SPU condition. The additional AFW supplied by the second pump will bring the plant to a stable condition, precluding a pressurizer water-solid condition. In response to a staff RAI, the licensee stated the additional flow is only equivalent to that which the other MDAFWP can supply (the TDAFWP has twice the capacity of the MDAFWP), which bounds the possibility of a failure in one of the MDAFW pumps or the TDAFWP as is currently assumed in the analysis of record (Reference 16). In response to another staff RAI, the licensee confirmed the IP2 SPU analyses demonstrated that the AFW system provides sufficient flow to prevent both the exceeding of specified fuel design limits and the occurrence of system overpressurization. The analysis performed showed the pressurizer did not reach a water-solid condition and the pressurizer did not release any water when crediting the additional AFW flow under SPU conditions. The analysis performed also showed the peak RCS and MSS pressures remained below the 110% design pressures throughout the transient. With respect to DNB, the LONF accident was bounded by the loss of load accident. For the LONF transient, the RCS temperature increases gradually as the SGs boil down to the low-low level trip setpoint, at which time the reactor trips and immediately after, the turbine trips. Nuclear power drops at nearly the same time steam flow drops and there is very little mismatch between the primary and secondary systems to force an RCS heatup. For the loss of load transient, the turbine trip is the initiating event, and the power mismatch between the primary and secondary systems is more severe. The RCS heatup will be much more severe for the loss of load transient than the LONF transient, in which case the loss of load transient demonstrated the minimum DNBR remained greater than the safety analysis limit. In Section 10.15 of the application report, the licensee stated the EOP step for addition of supplemental feedwater to SGs after a trip already exists and operators have been able to complete this action in less than 10 minutes. The procedure will be revised to provide specificity for the flow and time requirements for the SPU conditions. In its submittal, the licensee also stated changes to the operating procedures and setpoints will be part of operator training to be conducted prior to implementation of the SPU.

The NRC staff reviewed the licensee's analysis for the LONF flow transient and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed power level and was performed using an acceptable analytical model. The staff finds the licensee demonstrated that the minimum DNBR safety analysis limit will not be exceeded, pressure in the RCS and MSS will be maintained below 110% of the design pressures, and a more serious plant condition is precluded. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the loss of normal feedwater flow event.

3.2.2.12.2.7 Loss of Reactor Coolant Flow

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer and a subsequent increase in fuel temperature. Accompanying fuel damage could then result if specified acceptable fuel design limits are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, and pressure in the RCS and MSS being maintained below 110% of the design pressures. Specific review criteria are contained in SRP Sections 15.3.1/15.3.2.

The licensee re-analyzed the partial loss and complete loss of reactor coolant flow at SPU conditions. The licensee used the RTDP methodology, the RETRAN code and VIPRE code in accordance with the methodologies described in References 38 and 39. For the partial loss of flow incident, the DNBR did not decrease below the safety analysis limit at any time during the transient. The peak primary and secondary system pressures remained below their respective limits at all times. For the complete loss of flow event, the licensee analyzed both undervoltage and frequency decay transients. The VIPRE analyses for these scenarios confirmed that the minimum DNBR values were greater than the safety analysis limit. The peak primary and secondary system pressures remained below their respective limits at all times. The results of the licensee's analyses demonstrated that the acceptance criteria for these events were satisfied.

The NRC staff reviewed the licensee's analyses of the loss of reactor coolant flow and concludes that the licensee performed the analyses using acceptable analytical models. The staff finds the licensee demonstrated that the reactor protection and safety systems will continue to ensure the minimum DNBR will remain above the safety analysis limit and pressure in the RCS and MSS will be maintained below 110% of the design pressures. The staff further concludes that the licensee will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the loss of reactor coolant flow.

3.2.2.12.2.8 Locked Rotor Accident

In a locked rotor accident, the events postulated are an instantaneous seizure of the rotor or the break of the shaft of a reactor coolant pump (RCP) in a pressurized-water reactor (PWR). Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The locked rotor accident is an ANS condition IV event and the acceptance criterion is based on rods-in-DNB being less than or equal to that assumed in the radiological dose analyses for the locked rotor/shaft break event.

The licensee re-analyzed the locked rotor accident using the most limiting combination of conditions for the locked rotor and pump shaft break events with a total of four loops in operation. The first case used the STDP methodology to evaluate the RCS pressure and fuel clad temperature transient conditions. The second case used the RTDP methodology to

evaluate DNB in the core during the transient. The licensee performed the analyses using the RETRAN computer code to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE subchannel code calculated the hot channel heat flux transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR value remained above the safety analysis limit. The analysis calculated zero percent rods in DNB, but assumed 5% of the fuel rods in the core suffered damage for the radiological dose analyses for this event.

The NRC staff reviewed the licensee's analyses of the locked rotor and pump shaft break events and determined that the licensee's analyses were performed using acceptable analytical models. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the locked rotor accident.

3.2.2.12.2.9 Uncontrolled RCCA Withdrawal from Subcritical Condition

An uncontrolled RCCA withdrawal from subcritical condition may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will add positive reactivity to the reactor core, resulting in a power excursion. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, and the peak fuel centerline temperature remaining within acceptable limits. Specific review criteria are contained in SRP Section 15.4.1.

In performing its analysis, the licensee assumed the reactor was at hot zero power (HZP) conditions: using the most positive moderator temperature coefficient (MTC) since this yields the maximum rate of power increase; basing the total reactor trip reactivity on the assumption that the highest control rod assembly was stuck in its fully withdrawn position; and using a conservatively low Doppler power reactivity coefficient value. The licensee used the STDP to perform this analysis. The spatial kinetics computer code, TWINKLE, was used to calculate the core average nuclear power transient, including Doppler and moderator reactivity. The FACTRAN computer code used the average nuclear power calculated by TWINKLE and performed a fuel rod transient heat transfer calculation to determine average heat flux and temperature transients. The average heat flux calculated by FACTRAN was used in the VIPRE-W computer code for DNBR calculations. The analysis showed the limiting case result for minimum DNBR remained above its safety analysis limit and the maximum fuel centerline temperature remained below its safety analysis limit as provided in Table 3-1 of the licensee's June 16 letter.

The NRC staff reviewed the licensee's analysis of the uncontrolled RCCA withdrawal from a subcritical condition and concludes that the licensee's analysis was performed using acceptable analytical models, as stated above. The staff finds that the licensee demonstrated the DNBR safety analysis limit will not be exceeded and the peak fuel centerline temperature will remain below the safety analysis limit under SPU conditions. The staff concludes that the licensee will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical condition.

3.2.2.12.2.10 Uncontrolled RCCA Withdrawal at Power

An uncontrolled RCCA withdrawal at power event may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, and pressure in the RCS and MSS being maintained below 110% of the design pressure. Specific review criteria are contained in SRP Section 15.4.2.

In performing its analysis, the licensee assumed a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. Specifically, the highest RCCA was stuck in its fully withdrawn position, and the maximum positive reactivity insertion rate was greater than the results of a simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed. The licensee used the RTDP methodology and the RETRAN computer code for the transient analysis simulation. The code-computed plant variables including temperatures, pressures, power level and DNBR. The analysis demonstrated the RPS actuates for various combinations of reactivity insertion rates and initial conditions to provide adequate protection. All the transient responses with minimum feedback and maximum feedback at various power levels showed the minimum value of DNBR was always larger than the safety analysis limit for IP2 at SPU conditions. The peak RCS pressure and peak MSS pressure remained below the 110% of their design pressures, as provided in Table RAI 3-1(proprietary) of Reference 16.

The NRC staff reviewed the licensee's analysis of the uncontrolled RCCA withdrawal at power and concludes that the licensee's analysis was performed using acceptable analytical models, as stated above. The staff finds that the licensee demonstrated the DNBR safety analysis limit will not be exceeded and RCS and MSS peak pressures will be maintained below the 110% design value. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the uncontrolled RCCA withdrawal at power.

3.2.2.12.2.11 Rod Cluster Control Assembly Drop/Misoperation

RCCA misoperation accidents include dropping one or more RCCAs within the same group, dropped RCCA banks, and statically misaligned RCCAs. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, and the peak linear heat generation not exceeding a value that could cause fuel centerline melting. Specific review criteria are contained in SRP Section 15.4.3.

In performing its analysis, the licensee assumed a range of negative reactivity insertions from 100 to 1000 percent millirho (pcm) to simulate a dropped RCCA event and a range of MTCs which bounded the limiting time in life. The generic transient analysis statepoints used for IP2 are based on a four-loop plant having a 12-foot height core while assuming the automatic rod withdrawal feature of the rod control system is disabled. The licensee used the RTDP methodology and the LOFTRAN computer code for the transient analysis simulation of a dropped rod. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation were performed in accordance with the Dropped Rod Methodology described in WCAP-11394 (Reference 33). In its response to a staff RAI, the licensee provided the data

which showed the minimum DNBR during the dropped RCCA event remained above the safety analysis limit DNBR. The misaligned RCCA analysis at SPU conditions used the VIPRE-01 computer code. This analysis was done for a rod fully withdrawn and a rod fully inserted. In both cases, the FΔH remained below the maximum FΔH safety analysis limit (proprietary). The maximum peak linear heat generation rates for the dropped rod or RCCA misalignment transients remained below the fuel centerline melting limit, which was established during the SPU analysis.

The NRC staff reviewed the licensee's analyses related to the RCCA drop/misoperation analyses for the uprated power of 3216 MWt and concludes that the licensee's analyses were performed using acceptable analytical models, as stated above. The staff finds the licensee demonstrated that the minimum DNBR will remain above the safety analysis limit, and the peak linear heat generation will not exceed the value that could cause fuel centerline melting. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed stretch power uprate acceptable with respect to the RCCA drop/misalignment transients.

3.2.2.12.2.12 Chemical and Volume Control System (CVCS) Malfunction

Unborated water can be added to the RCS, via the CVCS. The CVCS is designed to limit the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator with sufficient time to correct the situation in a safe manner. The operator must stop this unplanned dilution before the shutdown margin is lost. The acceptance criteria are based on the minimum DNBR remaining above the safety analysis limit, pressure in the RCS and MSS being maintained below 110% of the design pressures, and fuel temperature and fuel clad strain limits not being exceeded. Specific review criteria are contained in SRP Section 15.4.6.

The licensee re-analyzed the malfunction of the CVCS for the refueling, startup and full power modes using a logarithmic equation that could be solved for the time at which the core would become critical or all shutdown margin would be lost. Minimum reactor coolant volumes and maximum dilution flow rates were assumed for each case analyzed. To provide margin for future reload design activities, the licensee changed the critical boron concentration to a minimum value from 610 ppm to 660 ppm. For operation at power, startup, and hot standby modes, one or more RCPs are in service at IP2 and adequate mixing is assumed between the dilution injection point and the lower plenum of the reactor core preventing the introduction of a dilute slug entering the core to cause a power excursion. The licensee addressed cold and hot shutdown modes through the Interim Operating Procedure (IOP). The IOP is based upon a generic boron dilution analysis assuming active RCS and RHR volumes which are conservative with respect to IP2. The IOP addresses the potential effects of a dilution front and a limited active mixing volume. In addition, at least one RCP is in service in hot and cold shutdown modes. In the event of a boron dilution accident during hot or cold shutdown, use of the IOP provides the plant operator with sufficient information to maintain an appropriate boron concentration and to assure the regulatory criteria are met. Prior to entering the refueling mode, plant procedures require isolation and documentation of paths that could cause dilution. The analysis showed that the time for operator action to mitigate the consequences of this event prior to a loss of shutdown margin during refueling, startup, or at full operation met the acceptance criteria set forth in the SRP. Therefore, the DNBR safety analysis limit was not

violated, pressure did not increase to 110% of RCS or MSS design pressures, and fuel temperature and clad strain limits were not exceeded.

The NRC staff reviewed the licensee's analyses of the CVCS malfunction transients and concludes that the licensee's analysis was performed using an acceptable analytical model. The staff finds the licensee demonstrated that the critical heat flux will not be exceeded, pressure will be maintained below 110% of the design values and fuel and clad strain limits will not be exceeded. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the CVCS malfunction transient.

3.2.2.12.2.13 Rupture of a CRDM Housing (RCCA Ejection)

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. The NRC staff evaluates the consequences of a control rod ejection accident to determine the potential damage to the RCPB, and whether the fuel damage resulting from such an accident could impair cooling water flow. The acceptance criteria are based on ensuring that the effects of postulated reactivity accidents do not result in damage to the RCPB greater than limited local yielding, and do not cause sufficient damage to significantly impair the capability to cool the core. Specific review criteria contained in SRP Section 15.4.8 and used to evaluate this accident include:

a. Reactivity excursions should not result in a radially averaged enthalpy greater than 280 cal/gm at any axial location in any fuel rod.
b. The maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the "Service Limit C" as defined in the American Society of Mechanical Engineers, *Boiler and Pressure Vessel Code* (ASME Code).

The licensee performed the calculation for the transient in two stages: first an average core channel calculation, and then a hot region calculation. The analysis used the methodology described in WCAP-7588 (Reference 40). The licensee used the TWINKLE computer code to perform its average core transient analysis and the FACTRAN code to perform the hot region analysis. NRC staff RAI results submitted by the licensee in Table 3-1 of its June 16 letter for the rod ejection analysis showed the fuel pellet average enthalpy and the clad limits were not exceeded and the maximum RCS peak pressure did not exceed the faulted condition stress limits.

The NRC staff reviewed the licensee's analysis of the rod ejection accident and concludes that the licensee's analysis was performed using acceptable analytical models, as stated above. The staff finds the licensee demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could result in damage to the RCPB greater than limited local yielding or cause sufficient damage that would significantly impair the capability to cool the core. The staff concludes that the licensee will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the rod ejection accident.

3.2.2.12.2.14 SG Tube Rupture

An SG tube rupture (SGTR) event causes direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and SG safety or atmospheric relief valves. Reactor protection and engineered safety features are actuated to mitigate the accident and restrict the offsite dose within the guidelines of 10 CFR 50.67. The NRC staff's review for the SGTR focused on the thermal and hydraulic analysis for the SGTR in order to support the review related to 10 CFR 50.67 for radiological consequences, which is addressed in Section 3.5 of this SE, and confirm that there is no SG overfill during the mitigation of this event which could cause unacceptable radiological consequences or potential failure of the MSS.

The licensee performed an SGTR thermal-hydraulic analysis for calculation of the radiological consequences under SPU conditions. In order to model the SGTR, the licensee used the modified version of the LOFTRAN code to include an enhanced SG secondary-side model, a tube rupture break flow model, and improvements to allow simulation of operator actions. This version of the code is referred to as LOFTTR2 and was approved by the NRC in WCAP-10698-P-A (Reference 31). Following an SGTR, a loss of offsite power is assumed to occur concurrent with the reactor trip resulting in the release of steam to the atmosphere via the SG atmospheric relief valves and/or safety valves. The licensee performed the LOFTTR2 analyses for the time period from the SGTR initiation until the primary and secondary pressures were equalized. The water volume in the secondary side of the ruptured SG was calculated as a function of time to demonstrate that overfill does not occur. In response to a staff RAI regarding the 60-minutes operator action time for terminating the break flow, the licensee responded that operators are currently required to terminate break flow within 45 minutes, which is required to be demonstrated on the plant simulator as part of operator training. In the additional information submitted by the licensee, the results of the analysis performed, showed the SG will not overfill in the 60 minutes the operator has to terminate the break flow.

The NRC staff reviewed the licensee's analysis of the SGTR accident and concludes that the licensee's analysis adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods. The staff concludes that the assumptions used in this analysis are conservative, and that the event does not result in an overfill of the SG. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SGTR.

3.2.2.12.2.15 Anticipated Transients Without SCRAM (ATWS)

An ATWS is defined as an anticipated operational occurrence followed by the failure of the reactor protection system specified in GDC-20. 10 CFR 50.62 provides the regulations regarding ATWS, and requires that each PWR must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system.

The NRC staff's review verifies that the above requirements are satisfied and that the setpoints for the ATWS mitigating system actuation circuitry (AMSAC) and diverse scram system (DSS) remain valid for the proposed stretch power uprate. In addition, for plants where a DSS is not specifically required by 10 CFR 50.62, the NRC staff verifies that the consequences of an

ATWS are acceptable. The acceptance criteria is that peak primary system pressure should not exceed the ASME Service Level C limit of 3215 psia. The peak ATWS pressure is primarily a function of the MTC and the primary system relief capacity.

The licensee re-analyzed the loss of main feedwater ATWS event to demonstrate that all appropriate acceptance criteria are satisfied under SPU conditions using the LOFTRAN computer code. The peak primary system pressure obtained from this analysis was 3205 psia, or 10 psi margin to the ATWS peak RCS pressure limit of 3215 psia. The IP2 TS indicate the MTC upper limit shall be <0 pcm/EF at hot zero power. The licensee is maintaining this limit in the proposed SPU. In its response to a staff RAI, the licensee stated as part of the SPU analysis, specific calculations were done examining the MTC conditions for future uprate cycles. These calculations show that the fuel performance characteristics for future cycles will result in a zero power MTC of no more than 0 pcm/EF throughout core life. To ensure that the MTC upper limit TS will continue to be met for each future operating cycle, the licensee stated the MTC uppper limit is included with the limiting conditions examined for every cycle as part of the Westinghouse Reload Safety Evaluation Methodology.

The NRC staff concludes that the licensee has demonstrated that the AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed stretch power uprate. The licensee showed that the plant is not required by 10 CFR 50.62 to have a DSS. Additionally, the licensee demonstrated, through acceptable analysis, that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3215 psia. Based on this, the NRC staff concludes that the plant design will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed stretch power uprate.

3.2.3 Summary

The NRC staff reviewed the licensee's evaluations, analyses and proposed TS changes to support operation of IP2 at the proposed stretch power uprate level of 3216 MWt. Additionally, the NRC staff reviewed the use of methodologies not previously approved for use at IP2. Based on its review, the staff finds that the supporting safety analyses were performed with NRC-approved computer codes and methods; their implementation at IP2 were acceptable; the input parameters of the analysis adequately represent the plant conditions at the power level assumed in each analysis; and the analytical results are within the applicable acceptance criteria. Therefore, the NRC staff concludes that the supporting analyses are acceptable. The NRC staff also finds that the proposed TS changes discussed in this evaluation adequately reflect the results of the acceptable supporting analysis, and therefore, concludes that the proposed TSs are acceptable for the implementation of the stretch power uprate for IP2.

3.3 Electrical Systems

3.3.1 Environmental Qualification (EQ) of Electrical Equipment

3.3.1.1 Regulatory Evaluation

The term "environmental qualification" applies to equipment important to safety to assure this equipment remains functional during and following design-basis events. The NRC staff's review covers the environmental conditions that could affect the design and safety functions of

electrical equipment including instrumentation and control. The NRC staff's review is to ensure compliance with the acceptance criteria, thus ensuring that the equipment continues to be capable of performing its design safety functions under all normal environmental conditions, anticipated operational occurrences, and accident and post-accident environmental conditions. Acceptance criteria are based on 10 CFR 50.49 as it relates to specific requirements regarding the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

3.3.1.2 Technical Evaluation

The licensee has reviewed the electrical equipment EQ program for the SPU. The review was performed for the new accident temperature, pressure, humidity, submergence and radiation dose associated with the uprate to environmental conditions in the EQ Program. The SPU has no effect on the qualification of equipment inside containment with respect to the temperature, pressure, but does have an effect with respect to qualification to radiation dose. The SPU radiation doses have increased as a result of the increased power, the associated allowance for instrument error, and the fuel cycle extension to 24 months. The total integrated dose for 40-year normal operation and accident radiation of 2.54×10^8 rads exceeds the documented qualification doses for several equipment. The licensee made further evaluation of the exposure of the critical radiation sensitive parts. Final evaluation of the exposure of the radiation sensitive parts determined that all equipment was acceptable in accordance with the EQ Program. All potentially submerged cables are qualified for the SPU with large margins. All equipment inside reactor containment is qualified for SPU conditions.

The power uprate has little effect on the qualification of equipment outside containment with respect to the temperature, except for equipment in the main steam (MS) penetration area. The temperature during normal operation is unchanged and is bounded by the qualification basis of 105 EF. The following bounding high-energy line breaks (HELBs) for EQ equipment outside containment bound the conditions of the SPU:

- The MSLB in the steam and feed-line penetration area
- The MS supply line to the TDAFWP in the AFWP room
- The SG blowdown line break in the pipe penetration area

The equipment that is required to respond to these HELBs has been evaluated further using thermal lag analysis of the equipment response to the break environment for the spectrum of breaks. The equipment in the steam and feed line penetration area is qualified considering the thermal lag analysis. The beta radiation dose to EQ equipment outside containment is negligible. All equipment outside containment required for accident response has been justified as qualified.

3.3.1.3 Conclusion

The NRC staff has reviewed the licensee's submittal of the effects of the proposed power uprate on the EQ of the electrical equipment and concludes that the electrical equipment continues to meet the relevant requirements of 10 CFR 50.49. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the environmental qualification of electrical equipment.

3.3.2 Offsite Power System

3.3.2.1 Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covers the information, analyses and documents for the offsite power system and the stability studies for the electrical transmission grid. The focus of the review relates to the basic requirement that loss of the nuclear unit, the largest operating unit, the largest operating unit on the grid or the loss of the most critical transmission line will not result in the loss of offsite power to the plant. Branch Technical Position (BTP) Instrumentation & Control Systems Branch (ICSB) 11, "Stability of Offsite Power Systems," outlines an acceptable approach to addressing the issue of stability of offsite power systems. Acceptance criteria are based on GDC 17 of Appendix A to 10 CFR Part 50. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to 8.2 and BTPs PSB-1 and ICSB-11.

3.3.2.2 Technical Evaluation

As described by the licensee's January 29, 2004, application, the main generator is rated at 1439.2 Megavolts-ampere (MVA) at a 0.91 power factor (pf). The main generator provides power through the isolated phase bus at 22 kV to both the main transformer and the unit auxiliary transformer (UAT). The generator voltage is stepped up through the main transformer to a 345 kV system. The preferred ac power source provides offsite ac power to the auxiliary power distribution system for the startup, operation, or shutdown of the station. The preferred alternating current (ac) power also provides a source of offsite ac power to all emergency loads necessary for the safe shutdown of the reactor. The electrical distribution system has been previously evaluated to conform to GDC 17.

3.3.2.2.1 Grid Stability

The licensee analyzed the grid stability by using the stability data provided by the NYISO (New York Independent System Operator). Stability plots compared the response of several IP2 generator variables before and after the uprate, as well as selected 345 kV voltages. The study concluded that the system is shown to be stable for all the contingencies, and the plots indicate a very similar response at IP2 before and after the uprate. The main generator can provide rated output (1439.2 MVA) when operated from 0.91 pf, lagging, up to and including unity pf, at 75 psig hydrogen pressure. The reactive capability of the main generator meets the normal power requirement of 600 MVAR lagging and 100 MVAR leading, and the IP2 reactive power commitments. By letter dated June 16, 2004, the licensee provided additional information in support of the NRC staff's request for the compensatory measures that the licensee would take to address the depletion of the nuclear unit MVAR capability on a grid-wide basis. The licensee stated that IP2 is connected to the Con Edison electrical transmission system that is operated under the rules of the NYISO. The NYISO has reviewed and approved the MVAR capability of IP2 at SPU conditions. Any depletion of MVAR capability on a grid-wide basis would be addressed by the NYISO requesting generating units connected to the transmission system to increase MVAR (either lagging or leading). Once the maximum MVAR capability of the units connected to the system has been reached, the NYISO has the authority to order the reduction in real power measured in megawatts to match the available MVAR level. IP2 is obligated to respond to such a request.

The NRC staff reviewed the licensee's submittal and concluded that there is no anticipated significant effect on grid stability with the power uprate and, therefore, the design is acceptable.

3.3.2.2.2 Main Generator

The main generator is rated at 1439.2 MVA (based on 75 psig hydrogen pressure) at 0.91 pf. or 1310 MWe. The generator capability curve shows that the machine is capable of continuous operation at an output of 1219 MWe with 0.92 pf up to 1325 MWe at unity power factor. Maximum required output at SPU conditions is assumed to be 1100 MWe which is much less than the main generator rating. The reactive capability of the main generator meets the normal power requirement of 600 MVAR lagging and 100 MVAR leading, and the IP2 reactive power commitments. A review of generator capability curve shows that the main generator is adequate to support the unit operation at SPU conditions.

The NRC staff reviewed the licensee's submittal and concluded that the main generator will continue to operate safely at the anticipated power uprate and, therefore, the design is acceptable.

3.3.2.2.3 Main Power Transformer

The main generator delivers its power output to two main power transformers (MTs). The name plate rating of each main transformer is 542 MVA FOA @ 55 °C, and 607 MVA FOA @ 65 °C with the transformer maximum rating of 1214 MVA at the 65 °C rise over ambient. The MT loading at SPU is determined assuming house loads are supplied from the main generator via the UAT when the unit is operating at full power. The maximum calculated load for the MT is 1137.6 MVA which is below the maximum rating of 1214 MVA. Therefore, the MT is adequately sized to support unit operation at SPU conditions. However, the licensee plans to modify the online monitoring system with the installation of hot-spot thermography for better monitoring the condition of the MT with the power uprate.

The NRC staff reviewed the licensee's submittal and concluded that the MT will continue to operate at the anticipated power uprate after modifying the main power transformer online monitoring and is acceptable.

3.3.2.2.4 Isolated Phase Bus

The isolated phase (isophase) bus duct connects the main generator to the primary windings of the MTs and the UAT. The isophase bus system is organized into three segments. The first segment runs from the generator terminals to the point where the main bus splits into the two segments that run to the two MTs. This first segment has a forced air-cooled rating of 32 kA at 22 kV, 65 °C. The second segment of the main bus runs from the split to each MT. These segments have a forced air-cooled rating of 16 kA at 22 kV, 65 °C. The third segment runs from the main bus tap to the UAT. This segment has a self-cooled rating of 1.5 kA at 22 kV. This segment does not have a forced-cooled rating.

The transformer test report shows the two MTs have identical MVA ratings and impedances. Since the current splits evenly between the transformers in proportion to the impedance, the current to each MT primary winding will be the same. The 16 kA portion of the bus between the split and UAT tap is the most limiting case since it carries the generator output to one MT plus

the UAT load. The anticipated worst-case loading at SPU exceeds the continuous current rating of the isophase main bus. Based upon the results of an evaluation, the existing coolers will be upgraded to provide the additional main bus ampacity required to support unit operation at SPU conditions.

The NRC staff reviewed the licensee's submittal and concluded that the isophase bus main duct will continue to operate at the anticipated power uprate after upgrading the existing main isophase bus duct coolers and is acceptable.

3.3.2.2.5 Station Auxiliary Transformer

The station auxiliary transformer (SAT) nameplate rating is 138/6.9 kV, 43 MVA FOA @ 55 EC rise, and 48.16 MVA FOA at 65 EC rise. The transformer is equipped with an automatic load tap changer. The SAT provides power to the balance of plant (BOP) systems under abnormal operating conditions. Unit operation at SPU will result in an increase in SAT loading when the house loads are transferred because the horsepower required by large pump motor drives has increased with the power uprate. The worst-case total secondary load on the SAT is 41.38 MVA which is less than the SAT maximum name plate rating of 43 MVA FOA at 55 EC rise, and 48.16 MVA FOA at 65 EC rise.

The NRC staff reviewed the licensee's submittal and concluded that the SAT has adequate capacity to support unit operation at SPU conditions and is acceptable.

3.3.2.2.6 Unit Auxiliary Transformer

The UAT nameplate rating is 22/6.9 kV, 43 MVA FOA @ 55 °C rise, and 48.16 MVA FOA at 65 EC rise. The transformer is equipped with an automatic load tap changer. The UAT supplies power to BOP systems under normal operating conditions. The worst-case total secondary load on the UAT is 38.73 MVA which is less than the UAT maximum name plate rating of 43 MVA FOA at 55 EC rise, and 48.16 MVA FOA at 65 EC rise.

The NRC staff reviewed the licensee's submittal and concluded that the UAT has adequate capacity to support unit operation at SPU conditions and is acceptable.

3.3.2.3 Conclusion

The NRC staff has reviewed the licensee's analyses for the effect of the proposed power uprate on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed modifications to the main power transformer online monitoring and the main isophase bus duct coolers. The NRC staff further concludes that the impact of the proposed power uprate on grid stability is insignificant. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the offsite power system.

3.3.3 Onsite AC Power Systems

3.3.3.1 Regulatory Evaluation

The ac onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to the safety-related equipment. The NRC staff's review covers the descriptive information, analyses, and referenced documents for the ac onsite power system. Acceptance criteria are based on GDC 17 as it relates to the capability of the ac onsite power system to perform its intended functions during all plant operating and accident conditions. Specific review criteria are contained in SRP Section 8.1 and 8.3.1.

3.3.3.2 Technical Evaluation

The onsite standby power supply consists of three independent emergency diesel generators (EDGs). The emergency bus loading was evaluated to determine any load increases that would effect it as a result of the power uprate. A review of the electrical loading associated with each EDG determined that there is an insignificant load increase due to containment recirculation fan motor power requirements (from 223 to 227 kW). This increase is less than the maximum load of 250 kW assumed in the existing EDG load study. Therefore, the EDGs are not affected by the SPU.

3.3.3.3 Conclusion

The NRC staff has reviewed the licensee's submittal for the effect of the proposed power uprate on the onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed power uprate on the system's functional design. The NRC staff further concludes that the ac onsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the onsite ac power system.

3.3.4 Onsite DC Power Systems

3.3.4.1 Regulatory Evaluation

The direct current (dc) power systems include those dc power sources and their distribution systems and auxiliary supporting systems provided to supply motive or control power to safety-related equipment. The NRC staff's review covers the information, analyses, and referenced documents for the dc onsite power system. Acceptance criteria are based on GDC 17 and 10 CFR 50.63 as they relate to the capability of the onsite electrical power to facilitate the functioning of structures, systems, and components (SSCs) important to safety. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2.

3.3.4.2 Technical Evaluation

The licensee has adequately accounted for the effects of the proposed power uprate on the system's functional design. The dc system is not affected by the SPU since no new loads were added to the system.

3.3.4.3 Conclusion

The NRC staff has reviewed the licensee's analyses for the effect of the proposed power uprate on the dc onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed power uprate on the system's functional design. The NRC staff further concludes that the dc onsite power system will continue to meet the requirements of GDC 17 and 10 CFR 50.63 following implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to the dc onsite power system.

3.3.5 Station Blackout (SBO)

3.3.5.1 Regulatory Evaluation

An SBO refers to the complete loss of alternating current (ac) electric power to the essential and nonessential switchgear busses in a nuclear power plant. SBO involves the loss of offsite power concurrent with turbine trip and failure of the onsite emergency ac power system. SBO does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from "alternate ac sources" (AAC). The NRC staff's review focuses on the impact of the proposed power uprate on the plant's ability to cope with and recover from an SBO event. The specified blackout duration is based on the factors detailed in 10 CFR 50.63. Specific review criteria are contained in SRP Section 8.1 and Appendix B to SRP 8.2.

3.3.5.2 Technical Evaluation

10 CFR 50.63, "Loss of all alternating current power," requires that nuclear power plants be capable of withstanding a total loss of offsite ac power and onsite emergency ac power supplies. The NRC issued RG 1.155 to provide guidance in responding to the SBO Rule. This RG endorses the Nuclear Management and Resource Council (NUMARC) "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," NUMARC-87-00, dated November 1987. The SBO minimum required coping duration for IP2 was determined to be 8 hours. The AAC power source consists of combustion gas turbines. The AAC power sources have sufficient capacity and capability to provide power to the shutdown buses within 1 hour of the SBO event for the required duration of 8 hours. The IP2 SBO coping analysis addresses the following topics:

- Condensate inventory for decay heat removal
- Class 1E battery capacity
- Compressed air
- Effects of loss of ventilation
- Containment isolation

3.3.5.2.1 Condensate inventory for decay heat removal

The condensate inventory for decay heat removal was determined using the methodology in NUMARC 87-00, which provides a bounding analysis for assessing condensate inventory. The volume of water required for 8 hours of decay heat removal and primary system cooldown was 142,850 gallons. The TSs require that a minimum of 360,000 gallons of water must be

available in the condensate storage tank (CST) during plant operation above 350 °F. Therefore, the NRC staff finds that there is sufficient margin between the minimum required volume of water in the CST and the volume of water required for coping with an SBO event under SPU conditions.

3.3.5.2.2 Class 1E battery capacity

Evaluation of plant fluid systems affected by operation at SPU conditions shows that there are no new SBO loads that require 125 Vdc control or motive power. Accordingly, there is no change in the ability of IP2 to cope with an SBO event under SPU conditions.

3.3.5.2.3 Compressed air

The air operated valves needed to cope with an SBO can either be operated manually or have sufficient backup sources independent of AC power for 1 hour coping duration, at which time the AAC power source will become available. A TDAFWP, which operates during an SBO, requires the operation of pneumatic valves to admit water to the SGs. When instrument air is not available, these valves can be operated locally or with backup nitrogen supply. The atmospheric relief valves (ARVs) are pneumatically operated, with nitrogen back-up. However, the ARVs are not required to maintain the unit in a hot shutdown condition, since the main steam safety valves (MSSVs) are set to maintain reactor coolant temperature at approximately no-load temperature. All other air-operated valves are designed to fail in the correct or safe position. The power uprate does not affect these conclusions.

3.3.5.2.4 Effects of loss of ventilation

Existing plant SBO analyses identified the auxiliary feedwater pump room as the only area of concern in accordance with the criteria of NUMARC 87-00. The relevant inputs and assumptions used to analyze this space bound the process conditions identified for the SPU. Main steam temperatures are well within the margin of temperatures used in the auxiliary feedwater loss of ventilation scenario. The inputs and assumptions for the other spaces discussed in the loss of ventilation analysis are not affected by the SPU.

3.3.5.2.5 Containment isolation

An evaluation was performed confirming that appropriate containment integrity can be provided during an SBO event, where “appropriate containment integrity” is defined as providing the capability for valve position indication and closure of containment isolation valves independent of the preferred or Class 1E power supplies. The licensee reviewed those containment isolation valves requiring manual operation and closure capability to cope with an SBO. A total of 13 valves were identified requiring local manual closure to establish containment integrity. Eight of the 13 valves are addressed in the Emergency Operating Procedure (EOP) for loss of all AC power. The remaining 5 valves should remain in the open position under SBO conditions, thus assuring timely performance of the vital safety functions performed by these valves. The operation of these 5 valves is addressed in the EOPs for transfer to hot-leg and cold-leg recirculation. The SPU does not affect this evaluation.

3.3.5.3 Conclusion

The NRC staff has reviewed the licensee's analyses of the effect of the proposed power uprate on the plant's ability to cope with and recover from a SBO event for the period of time established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed power uprate on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following the implementation of the proposed power uprate. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to SBO.

3.3.6 Summary

The NRC staff has evaluated the effect of power uprate on the necessary electrical system and EQ of electrical components. Results of these evaluations show that following implementation of the proposed modifications to the main power transformer on-line monitoring and the main isophase bus duct coolers, the design will be acceptable for the SPU conditions. After the modifications, the design will meet the requirements of GDC 17, 10 CFR 50.49, and 10 CFR 50.63. The proposed change is, therefore, acceptable.

3.4 Civil and Engineering Mechanics

3.4.1 Regulatory Evaluation

This technical evaluation includes the structural and functional integrity of piping systems, components and their supports, including core support structures, which are designed in accordance with the rules of the ASME Code, Section III, Division 1, USAS B31.1 "Power Piping Code," and GDCs 1, 2, 4, 10, 14, and 15. The NRC staff review focused on verifying that the licensee has provided reasonable assurance of the structural and functional integrity of piping systems, components, component internals, and their supports under normal and vibratory loadings, including those due to fluid flow, postulated accidents and natural phenomena such as earthquakes.

The acceptance criteria are based on continued conformance with the requirements of the following regulations: (1) 10 CFR 50.55a and GDC 1 as they relate to structures and components being designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety function to be performed, (2) GDC 2 as it relates to structures and components important to safety being designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions, (3) GDC 4 as it relates to structures and components important to safety being designed to accommodate the effects of, and to be compatible with, the environmental conditions of normal and accident conditions, (4) GDC 10, as it relates to reactor internals, being designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences, (5) GDC 14 as it relates to the reactor coolant pressure boundary being designed, fabricated, erected, and tested to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture, and (6) GDC 15 as it relates to the reactor coolant system being designed with sufficient margin to ensure that the design conditions are not exceeded.

The specific review areas are contained in the NRC SRP Section 3.9. The review also includes the plant specific provisions of GL 89-10 and GL 96-05, as related to plant-specific program for Motor Operated Valves, GL 95-07, as related to the pressure locking and thermal binding for safety related gate valves, and the plant-specific evaluation of the GL 96-06 program regarding the over-pressurization of isolated piping segments.

3.4.2 Technical Evaluation

The NRC staff reviewed the IP2 power uprate amendment, as it relates to the effects of the power uprate on the structural and pressure boundary integrity of the NSSS and BOP systems. Affected components in these systems include piping, in-line equipment and pipe supports, the RPV, core support structures (CSS), reactor vessel internals (RVI), SGs, CRDMs, RCPs and pressurizer. The NRC staff's evaluation concerning the effects of the power uprate on the pertinent components is provided below.

3.4.2.1 Reactor Pressure Vessel

The proposed power uprate will increase the core power by approximately 3.26% above the currently authorized power level of 3114.4 Megawatts thermal (MW_t). The licensee reported that power increase will result in changing the design parameters given in Table 2.1-2 of Attachment III to the January 29 application.

The licensee evaluated the reactor vessel for the effects of the revised design conditions provided in Table 2.1-2 with respect to the core power level of 3216 MWt. The evaluation was performed for the limiting vessel locations with regard to stresses and cumulative fatigue usage factors (CUFs) in each of the regions, as identified in the reactor vessel stress reports for the core power uprated conditions. The regions of the reactor vessel affected by the power uprate include the RPV (main closure head flange, studs, and vessel flange), CRDM housing, outlet nozzles and supports, inlet nozzles and supports, vessel wall transition, core support pads, bottom head-to shell juncture, instrumentation tubes, and head adapter plugs. In its amendment request, the licensee indicated that the evaluation of the RPV was performed in accordance with the ASME Code, Section III, 1965 Edition. Table 5.1-1 provides the calculated maximum stresses and CUFs for the reactor vessel critical locations. The results indicate that the maximum primary plus secondary stresses for all the reactor vessel critical locations except the CRDM Housing are within the Code allowable limits of $3S_m$. The stress of CRDM Housing exceed the Code AV of $3S_m$. The licensee justified that the CRDM Housing remains in accordance with the Code by performing a simplified elastic-plastic analysis. The CUFs for all the reactor vessel critical locations remain below the allowable ASME Code limit of 1.0. Therefore, the NRC staff agrees with the licensee's conclusion that the current design of the reactor vessel continues to be in compliance with the licensing basis Codes for the proposed power uprate condition.

3.4.2.2 Reactor Core Support Structures and Vessel Internals

The licensee evaluated the reactor vessel core support and internal structures. The limiting reactor internal components evaluated include the lower core support plate, core barrel lower girth weld, lower support columns, mid core barrel, upper core barrel, core barrel nozzles, lower radial key base, lower radial key, upper support assembly, skirt, and flange. The licensee

indicated that reactor internals components were designed to meet the intent of Subsection NG of Section III using the ASME Code, 1965 Edition with Winter 1965 Addenda.

The licensee evaluated these critical reactor internal components considering the revised design conditions provided in Table 2.1-2 of Reference 14 for IP2 for the requested power level of 3216 MWt. The licensee indicated that the calculated stress for the limiting reactor internals are acceptable within the Code allowable limits. The calculated CUFs, as provided in Table 5.2-1 of the licensee's application, are less than the ASME Code allowable limit of 1.0. In addition, the licensee evaluated the flow induced vibration to assess the effect of the core flow thermal design parameters affected by the power uprate. The licensee determined that the design parameters used in the FIV calculation are within the allowable limits for the proposed uprate condition. In addition, the licensee indicated in its August 3, 2004, response (Reference 18) to the NRC staff's RAI that the testing performed at IP2 included the acquisition of data during hot functional testing (without the core) and subsequently with the core installed. The results of this testing program showed that the vibrational response of the reactor internals is small and that adequate margins of safety exist to accommodate the slight change in operating condition for the SPU with regard to flow induced vibration.

Based on the above evaluations, the NRC staff agrees with the licensee's conclusion that the reactor internal components at IP2 will be structurally adequate for the proposed power uprate.

3.4.2.3 Control Rod Drive Mechanisms

The pressure boundary portion of the CRDMs are those exposed to the vessel/core inlet fluid. IP2 has Westinghouse full-length L-106 CRDMs. The licensee evaluated the adequacy of the CRDMs by reviewing the IP2 original design analysis and the 1990 Uprate Program to compare the design-basis input parameters against the revised conditions of Table 2.1-2, of Reference 14 for the power uprate. The comparison shows that the IP2 original design analysis and the 1990 Uprate Program are bounding for the 3.26% power uprate. The Model L-106 CRDMs were originally designed and analyzed to meet the ASME Code, 1965 Edition through Summer 1966 Addenda, which is the Code of record. Tables 5.3-2 and 5.3-3 of the January 29 application provide the calculated stresses and CUFs for the critical CRDM locations at the proposed power uprate conditions, which are less than the ASME Code allowable limits.

On the basis of its review, the NRC staff concurs with the licensee's conclusion that the current design of CRDMs continues to be in compliance with licensing basis Codes and standards for the proposed power uprate.

3.4.2.4 Steam Generators

The licensee reviewed the existing structural and fatigue analyses of the SGs at IP2 and compared the power uprate conditions with the design parameters of the analysis of record for the Model 44F at IP2. Based on the comparison of key input parameters, the licensee developed scaling factors which were used to scale up the original stress and fatigue usage for the power uprate conditions. The evaluation was performed in accordance with requirements of the ASME Code, Section III, 1965 Edition through the Summer 1966 Addenda, which is the Code of record for SGs at IP2.

The calculated maximum stresses and cumulative fatigue usage factors for the critical SG components are provided in Table 5.6-2 of Reference 14. The critical SG components on the primary side are the divider plate, tubesheet and shell junction, tube-to-tubesheet weld, and tubes. The critical SG components on the secondary side are the main feedwater nozzle, secondary manway bolts and studs, and steam nozzle. The results indicate that the maximum calculated stresses for the critical components, except the divider plate, are below the Code-allowable limits. The licensee performed simplified plastic elastic analysis to determine that maximum stress in the SG divider plate was in accordance with the Code. The results provided in Table 5.6-2 also show that calculated CUFs are within the allowable limit of 1.0 for all the critical components, except for the SG secondary manway bolt. The licensee determined that based on the calculated CUF, the bolts must be replaced within 34 years of operation.

In addition, the licensee evaluated the flow induced vibration of the U-bend tubes for the Model 44F SGs at IP2. The licensee indicated that the calculated fluid-elastic stability ratio is less than the allowable limit of 1.0, and the maximum fluid induced displacement values due to turbulence and vortex shedding are insignificant. As a result, the licensee concluded that the flow induced vibration of SG tubes will remain within the allowable limits for the power uprate. The NRC staff concurs with the licensee's conclusion.

On the basis of its review, the NRC staff concludes that the licensee has demonstrated the maximum stresses and CUFs for the critical SG components are within the Code allowable limits and, therefore, acceptable for the proposed power uprate.

3.4.2.5 Reactor Coolant Pumps

The licensee reviewed the existing design basis analyses of the IP2 RCPs to determine the impact of the revised design conditions in Table 2.1-2. The licensee indicated that the evaluation was performed in accordance with the requirements of the ASME Code, Section III, 1965 Edition, with Winter 1965, Addenda which is the Code of record.

After the core power uprate, the RCS pressure remains unchanged. The licensee indicated that the design parameter of the RCP temperature as provided in Table 5.5-1 of the January 29 application for the power uprate condition is bounded by the present design basis. Also, there are no significant changes to the design thermal transients. The maximum stresses and CUFs for the RCP limiting components shown in Table 5.5-3 are within the Code allowable limits. As a result of the evaluation, the licensee concluded that the current IP2 Model 93 RCPs remain in compliance with the applicable ASME Code requirements for structural integrity at the proposed power uprate.

On the basis of its review, the NRC staff concurs with the licensee's conclusion that the current RCPs, when operating at the proposed conditions with a 3.26% power increase from the current rated power, will remain in compliance with the requirements of the codes and standards under which IP2 was originally licensed.

3.4.2.6 Pressurizer

The licensee evaluated the limiting design locations of the pressurizer components. The components in the lower end of the pressurizer (such as the surge nozzle, lower head/heater well, and support skirt) are affected by the pressure and the hot leg temperature. The

components in the upper end of the pressurizer (such as the spray nozzle, safety and relief nozzle, upper head/upper shell, manway, and instrument nozzle) are affected by the pressure and the cold leg temperature for operation at the uprated conditions. The evaluation was performed using the ASME Code, Section III, 1965 Edition through Summer 1966 Addenda, which is the Code of record for the IP2 pressurizer.

The key parameters in the current IP2 pressurizer stress report were compared against the revised design conditions in Table 2.1-2 for the proposed power uprate. The limiting operating conditions of the pressurizer occur when the RCS pressure is high and the RCS hot leg (T_{hot}) and cold leg (T_{cold}) temperatures are low. The proposed power uprate does not change the maximum RCS pressure and the pressurizer temperature (T_{sat}). Also, the change in T_{hot} due to the power uprate was minimal and bounded by the existing design basis analyses. However, there is a slight increase in thermal stress due to lower T_{cold} at the power uprate condition. The evaluation was performed to demonstrate the adequacy of the components in the upper end of the pressurizer. The calculated CUFs for limiting pressurizer locations at the uprated condition were found to be below the Code allowable limit of 1.0, as shown in Table 5.7-1. As a result of the above evaluation, the licensee concluded that the pressurizer components meet the stress and fatigue analysis of the Code for plant operation at the SPU conditions. The NRC staff agrees with the licensee's conclusion.

3.4.2.7 NSSS Piping and Piping Supports

The proposed power uprate of IP2 involves the increase of temperature difference across the RCS. The licensee evaluated the NSSS piping and supports by reviewing the design-basis analysis against the uprate power design system parameters, transients, and the LOCA hydraulic forcing function loads. The evaluation was performed for the reactor coolant loop (RCL) piping, primary equipment nozzles, primary equipment supports, and the pressurizer surge line piping. USAS B31.1 Power Piping Code, Summer 1973 Edition was used for the power uprate evaluation of IP2 RCS piping except the surge line which was evaluated in accordance with requirements in Subsection NB of the ASME Code, Section III, 1986 Edition, which is the Code of record. The calculated stresses are provided in Table 5.4-1 of the amendment request for the primary loop piping for the power uprate. The maximum calculated stresses are shown less than the Code allowable limits.

The licensee indicated that the design transients used in the evaluation of the RCS piping systems and equipment nozzles are unchanged since the current NSSS design transients remain bounding for the IP2 power uprate. The proposed power uprate does not change the maximum RCS pressure. The design basis LOCA forces due to postulated primary loop guillotine breaks have been eliminated using the loop leak-before-break (LBB) methodology for IP2. With the use of LBB technology, LOCA forces for the power uprate condition were derived based on postulation of breaks on the 14-inch surge line nozzle on the hot leg, the 10-inch accumulator line nozzle on the cold leg, and the 14-inch RHR line nozzle on the hot leg. As such, the design basis LOCA hydraulic forcing functions are bounding for the LOCA loads at the uprated power condition. Furthermore, the deadweight and seismic loads are not affected by the power uprate. The licensee concluded that the existing pipe stresses and support loads remain bounding for the power uprate for the NSSS components including the reactor cooling loop piping, the primary equipment nozzles, the primary equipment supports, pipe supports and the auxiliary equipment (i.e., heat exchangers, pumps, valves, and tanks). Therefore, these components will continue to be in compliance with the Code of record at IP2.

On the basis of its review of the licensee's submittal, the NRC staff concurs with the licensee's conclusion that the existing NSSS piping and supports, the primary equipment nozzles, the primary equipment supports, and the auxiliary lines connecting to the primary loop piping will remain in compliance with the requirements of the design basis criteria, as defined in the IP2 UFSAR, and are therefore, acceptable for the proposed power uprate up to 3216 MWt power level.

3.4.2.8 BOP Systems and Motor-Operated-Valves (MOVs)

The licensee evaluated the adequacy of the BOP systems based on comparing the existing design basis parameters with the core power uprate conditions. The BOP piping systems that were evaluated for the power uprate condition include the main steam, extraction steam, condensate, feedwater, heater drains, moisture separator and reheater drains, SG blowdown, circulating water, fuel pit cooling, and service water. The licensee evaluated these affected systems at the uprated power level by comparing the input parameters for the current piping analysis reports against the design parameters in Table 3.1-1 for up to 3216 MWt. In its response (Reference 18) to the NRC staff's RAI, the licensee provided maximum calculated stresses for the above evaluated BOP piping to be less than the allowable limits. As a result, the licensee concluded that the existing design basis analyses for the BOP piping, pipe supports, and components will satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from the proposed power uprate at IP2.

The licensee also reviewed the programs, components, structures, and generic letter issues as they pertain to the power uprate. Based on information provided by the licensee in its application and in its responses to the NRC staff's RAI (Reference 18), the NRC staff reviewed the licensee's evaluation, including specific examples, of the effect of the power uprate on the functionality of safety-related pumps and valves at IP2. The licensee evaluated the impact of the power uprate on its response to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." GL 89-10 requires that safety-related MOVs are analyzed and controlled to ensure they are capable of performing their required functions. The licensee indicated that the analysis of a steam line break inside the containment under the SPU conditions takes credit for the operation of the feedwater flow control valve isolation MOVs. These valves are not currently included in the GL 89-10 program and are being added. The licensee indicated that formal documentation for the GL 89-10 program file will be provided prior to operation at the SPU conditions. Additionally, the licensee indicated that the only MOV operating parameter affected by the SPU was the Feedwater System MOVs flow rate. This flow rate increased for the SPU. The licensee indicated that the MOV operating parameter changes on related GL 89-10 parameters was evaluated and determined to be acceptable. In Attachment III of licensee's application, the licensee assessed the impacts of the 3.26% power uprate on the GL 89-10 and GL 96-05 programs and found them to be acceptable.

The licensee evaluated the impact of the power uprate on its response to GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The licensee indicated that the only type of pressure locking or thermal binding (PLTB) that continued a potential concern, was thermal binding involving valve stem growth. The licensee evaluated this effect and determined that potential PLTB will not prevent the plant from achieving safe shutdown, as all valves remain operable. The licensee determined that the SPU does not introduce any increased challenge for PLTB and does not affect the results and conclusions of the current evaluation. The NRC staff finds the licensee's evaluation of the effect of the

proposed power uprate on the capability of safety-related pumps and valves at IP2 to be acceptable, based on the NRC staff's review of the information submitted by the licensee describing the scope, extent, and results (with specific examples) of the evaluation of safety-related pumps and valves at IP2.

The licensee evaluated the impact of the power uprate on its response to GL 96-06, "Assurance of Equipment Operability And Containment Integrity During Design-Basis Accident Conditions." GL 96-06 requested utilities to address the susceptibility of: (1) containment air cooler cooling water systems to either water hammer or two-phase flow conditions during postulated accident conditions, and (2) piping systems that penetrate containment to thermal expansion of fluid that could cause over pressurization of piping. In its response (Reference 18) to the NRC staff's RAI, the licensee indicated that an approximate 39% margin exits between the calculated maximum pressure for SPU conditions and the maximum allowable pressure specified in USFAR. Due to the large existing stress margins, the licensee concluded that the stresses in this line under SPU continue to remain within the Code allowables. On the basis of the above review, the NRC staff concurs with the licensee's conclusions that the power uprate will have no adverse effects on the performance of safety-related valves and that the conclusions reached based on implementation of provisions in GL 95-07, GL 96-06, and GL 89-10 programs, remain valid.

As a result of the above evaluation, the NRC staff concludes that the BOP piping, pipe supports and equipment nozzles, and valves remain acceptable and continue to satisfy the design basis requirements for the proposed 3.26 proposed power uprate.

3.4.3 Summary

On the basis of its review in Section 3.4, the NRC 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, SGs, RCPs, and the pressurizer. The NRC finds the licensee's evaluation to be bounded by the licensing Code of record and the original design basis, and therefore, concludes the foregoing components to be acceptable for IP2 uprate operations at the proposed core power level of 3216 MW_t.

3.5 Dose Consequences Analysis

3.5.1 Regulatory Evaluation

The NRC staff addressed the impact of the proposed changes on previously analyzed design basis accident radiological consequences and the acceptability of the revised analysis results. The regulatory requirements for which the staff based its acceptance are the accident dose criteria in 10 CFR 50.67, as supplemented in Regulatory Position 4.4 of RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," and 10 CFR Part 50, Appendix A, GDC-19, "Control Room," as supplemented by Section 6.4 of the SRP. Except where the licensee proposed a suitable alternative, the NRC staff utilized the regulatory guidance provided in SRP Section 15.0.1, "Radiological Consequence Analysis Using Alternative Source Terms," in performing this review.

The NRC staff also considered relevant information in the IP2 UFSAR, TSs, and the NRC SE, dated July 27, 2000, for Amendment No. 211, which implemented an AST at IP2.

3.5.2 Technical Evaluation

The NRC staff reviewed the regulatory and technical analyses, as related to the radiological consequences of design basis-accidents (DBAs), performed by the licensee in support of its proposed license amendment. Information regarding these analyses was provided in Attachment III, Section 6.11 of the submittal, and in supplementary letters dated April 12 and June 16, 2004. The NRC staff reviewed the assumptions, inputs, and methods used by Entergy to assess the impact of the increase in rated core thermal power. The NRC staff performed independent calculations to confirm the conservatism of the licensee's analyses. However, the NRC staff's findings are based on the descriptions of the licensee's analyses and other supporting information docketed by Entergy.

3.5.2.1 Technical Evaluation Scope

3.5.2.1.1 Change to Definition of Dose Equivalent I-131

The licensee proposes to change the TS Section 1.1 definition of Dose Equivalent I-131 to be more consistent with the DBA dose analysis methodology previously adopted for use in Amendment No. 211, issued July 27, 2000. The changes delete reference to dose conversion factors not used any longer in the licensee's DBA dose analyses. The revised definition refers to those from Table 2.1 of the Environmental Protection Agency (EPA) Federal Guidance Report No. 11 (FGR-11). The NRC staff finds the use of dose conversion factors from FGR-11 to calculate the Dose Equivalent I-131 value, as well as DBA dose analyses, acceptable. This position is stated in RG 1.183.

3.5.2.1.2 Radiological Consequences of DBAs

In order to show that operation of IP2 at an uprated power of 3216 MWt remains within 10 CFR 50.67 and GDC-19 dose criteria, Entergy performed analyses of the radiological consequences of DBAs assuming the uprated power and using an AST. Amendment No. 211 approved implementation of AST at IP2, making the AST the licensing basis for IP2. In the time since the amendment was issued to IP2, the NRC staff has issued RG 1.183, which discusses the attributes of an acceptable AST and provides guidance on assumptions and inputs to be used in DBA radiological analyses using an AST. The radiological consequences analyses performed by Entergy to support the power uprate follow the RG 1.183 guidance.

The licensee's DBA dose analyses assumed a core thermal power of 3280.3 MWt, which includes a 2% uncertainty on the proposed rated power of 3216 MWt. Entergy performed following DBA analyses to support the power uprate:

- Main steam line break (MSLB)
- Locked RCP rotor
- Control rod ejection accident (REA)
- Steam generator tube rupture (SGTR)
- Small-break loss-of-coolant accident (SBLOCA)
- Large-break loss-of-coolant accident (LBLOCA)
- Fuel-handling accident (FHA)

3.5.2.2 MSLB Accident

The MSLB assumes that one main steam line is completely severed at a point outside the reactor containment. In accordance with RG 1.183 guidance, the licensee's analysis of the MSLB considers two cases. One case assumed the reactor coolant iodine activity concentration was elevated before the accident occurred, which is referred to as the pre-existing iodine spike case. The pre-existing iodine spike case assumed the reactor coolant was at the TS maximum iodine concentration of 60 µCi/gm of dose equivalent iodine-131 (DEI-131). The other case assumed that the accident causes an increase in the iodine activity in the reactor coolant, which is referred to as the accident-initiated iodine spike case. The reactor coolant was assumed to be at the TS equilibrium concentration of 1 µCi/gm DEI-131 at the time the accident starts. The accident is assumed to cause release of iodine from the fuel rod gaps to the reactor coolant that is a rate of 500 times the normal iodine release rate, for 3 hours. The licensee determined the length of time for the iodine spike so that no more than the total core iodine gap activity would be released in the spike. In each case, the secondary coolant was assumed to be at 0.15 µCi/gm DEI-131. The licensee also assumed the MSLB does not result in failed fuel.

In both cases, each of the SGs was assumed to be leaking reactor coolant through the SG tubes to the secondary system at the TS maximum of 150 gallons per day (gpd). The licensee also assumed that all leakage to the faulted SG (i.e., the SG on the same steam line that has broken) is released to the environment with no credit for retention of iodine in the SG. The entire amount of liquid in the faulted steam generator was assumed to be boiled off as steam and the iodine initially contained in the liquid released to the environment. The analysis assumed that because offsite power is not available, after the faulted SG was isolated, cooling of the RCS occurred through use of the MSSVs on the other 3 steam lines. At 30 hours after the MSLB, the licensee has analyses that show the reactor coolant has cooled enough so that RHR system is assumed to be capable of heat removal, and no further releases from the intact SGs are assumed.

The licensee's analyses assumed an iodine partitioning factor of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) in the intact steam generators. In other words, 1% of the iodine in the water in the intact SG is assumed be released as that water turns to steam. Any noble gas activity carried over through SG tube leakage was assumed to be immediately released to the environment.

For an MSLB, the low steamline pressure safety injection (SI) setpoint would be reached almost immediately after the event starts. The SI signal causes the control room heating, ventilation, and air conditioning (HVAC) system to enter the emergency filtration mode. In the MSLB radiological consequences analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation, 1 minute after the event.

The NRC staff finds that the licensee's analysis of the MSLB follows the guidance in RG 1.183. The MSLB assumptions and inputs the licensee used and the NRC staff evaluated are presented in attached Table 2. The licensee's analysis results show the radiological consequences of the MSLB, assuming either a pre-existing iodine spike or accident-initiated iodine spike, remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in attached Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the coolant activity source terms based on the licensee's information and found the licensee's coolant source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated MSLB accident.

3.5.2.3 Locked RCP Rotor Accident (LRA)

The licensee assumed an instantaneous seizure of an RCP rotor, which rapidly reduces reactor coolant flow through the affected loop. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products transfer from the primary reactor coolant system to the secondary system. Either the atmospheric relief valves (ARVs) or safety valves then release a portion of the radioactivity to the outside environment.

The licensee conservatively assumed 5% of the core's fuel cladding is damaged, although the transient analysis performed for the uprate shows no fuel rods were calculated to be subject to damage. The licensee applied the maximum radial peaking factor of 1.7 and the non-LOCA gap fractions from Table 3 of RG 1.183 in calculating the activity release from the damaged fuel. The licensee's analysis also assumed the reactor coolant iodine activity was elevated prior to the accident. This pre-existing iodine spike was assumed to raise the RCS iodine concentration to 60 μCi/gm of DEI-131. The noble gas and alkali metal activity concentration in the primary coolant when the postulated accident occurs is based on a fuel defect level of 1%. The iodine activity concentration in the secondary coolant is assumed to be 0.15 μCi/gm of DEI-131.

The licensee's analysis assumed that activity is released to the environment by way of primary-to-secondary SG tube leakage at the TS limit of 150 gpd/SG and steaming from the SG's secondary side. The activity in the SGs is released to the environment through steaming, with an assumed partitioning factor of 0.01. The iodine chemical form released to the atmosphere was assumed to be 97% elemental iodine and 3% organic iodine. The steaming releases were assumed to end at 30 hours into the accident, based on the calculated capability of the RHR system to remove all decay heat.

The licensee assumed that the control room HVAC is in the normal operation mode when the LRA occurs, and as activity builds up in the control room, a high-radiation signal is generated. The licensee assumed that the HVAC does not fully enter the emergency mode of operation until 10 minutes after the high-radiation signal. In the LRA analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation, 21 minutes after the event.

The NRC staff finds that the licensee's analysis of the LRA follows the guidance in RG 1.183. The LRA assumptions and inputs, that the licensee used and the NRC staff evaluated, are presented in the attached Table 3. The licensee's analysis results show the radiological consequences of the locked rotor accident remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the activity source terms based on the licensee's information and found the licensee's source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated locked rotor accident.

3.5.2.4 Control Rod Ejection Accident (REA)

The licensee assumed a mechanical failure of a CRDM pressure housing resulted in the ejection of an RCCA and drive shaft. As a result, damage to the fuel clad and a small amount of fuel melt would be expected. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products transfer from the RCS to the secondary system. A portion of the radioactivity is then released to the outside environment through either the atmospheric relief valves (ARVs) or safety valves.

Radioactive reactor coolant would also be discharged to the containment through the opening in the reactor vessel head where the rod was ejected. A portion of this radioactivity would be released to the environment through containment leakage, assumed to be at the TS maximum. The analysis assumed that the iodine in containment was 4.85% elemental, 0.15% organic, and 95% particulate. The licensee's analysis credited removal of particulate iodine in the containment atmosphere through sedimentation. This assumption was previously found acceptable in Amendment No. 211, which implemented an AST at IP2.

The licensee determined that less than 10% of the fuel rods are damaged enough that their gap activity is released. However, they conservatively assumed 10% of the core fuel rods released their gap activity. The licensee assumed that 10% of the core iodine and noble gas activity and 12% of the alkali metal activity is in the fuel rod gap. The licensee applied the maximum radial peaking factor of 1.7 in calculating the activity release from the damaged fuel.

The licensee's analysis also assumed the reactor coolant iodine activity was elevated prior to the accident. This pre-existing iodine spike was assumed to raise the RCS iodine concentration to 60 µCi/gm of DEI-131. The noble gas and alkali metal activity concentration in the primary coolant when the postulated accident occurs is based on a fuel defect level of 1%. The iodine activity concentration in the secondary coolant is assumed to be 0.15 µCi/gm of DEI-131.

The licensee's analysis assumed that activity is released to the environment by way of primary-to-secondary SG tube leakage at the TS limit of 150 gpd/SG and steaming from the steam generators secondary side. The activity in the SGs is released to the environment through steaming, with an assumed partitioning factor of 0.01. The iodine chemical form released to the atmosphere was assumed to be 97% elemental iodine and 3% organic iodine. The steaming releases were assumed to end at 30 hours into the accident, based on the calculated capability of the RHR system to remove all decay heat.

The low pressurizer pressure SI setpoint would be reached 61 seconds after the event starts. The SI signal causes the control room HVAC system to enter the emergency filtration mode. In

the REA radiological consequences analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation, 3 minutes after the event.

The NRC staff finds that the licensee's analysis of the REA follows the guidance in RG 1.183. The REA assumptions and inputs the licensee used and the NRC staff evaluated are presented in the attached Table 4. The licensee's analysis results show the radiological consequences of the control rod ejection accident remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the activity source terms based on the licensee's information and found the licensee's source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated rod ejection accident.

3.5.2.5 Steam Generator Tube Rupture (SGTR)

In accordance with RG 1.183 guidance, the licensee's analysis of the SGTR considers two cases. The pre-existing iodine spike case assumed the reactor coolant was at the TS maximum iodine concentration of 60 µCi/gm of dose equivalent iodine-131 (DEI-131). The accident-initiated iodine spike case assumed the reactor coolant to be at the TS equilibrium concentration of 1 µCi/gm DEI-131 at the time the accident starts. The accident is assumed to cause release of iodine from the fuel rod gaps to the reactor coolant that is a rate of 335 times the normal iodine release rate, for 4 hours. The licensee determined the length of time for the iodine spike so that no more than the total core iodine gap activity would be released in the spike. In each case, the secondary coolant was assumed to be at 0.15 µCi/gm DEI-131. The licensee also assumed the SGTR does not result in failed fuel.

In both cases, each of the intact SGs was assumed to be leaking reactor coolant through the SG tubes to the secondary system at the TS maximum of 150 gpd. The licensee calculated the amount of break flow through the ruptured SG that flashes to steam. The activity in this steam is released to the environment with no credit for retention of iodine in the SG. At 30 hours after the SGTR, the licensee has analyses that show the reactor coolant has cooled enough so that RHR system is assumed to be capable of heat removal, and no further releases from the intact steam generators are assumed.

The licensee's analyses assumed an iodine partitioning factor of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) in the intact SGs. In other words, 1% of the iodine in the water in the intact steam generator is assumed be released as that water turns to steam. Any noble gas activity carried over through SG tube leakage was assumed to be immediately released to the environment.

The low pressurizer pressure SI setpoint would be reached 4.83 minutes after the event starts. The SI signal causes the control room HVAC system to enter the emergency filtration mode. In

the SGTR radiological consequences analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation, 5.83 minutes after the event.

The NRC staff finds that the licensee's analysis of the SGTR follows the guidance in RG 1.183. The SGTR assumptions and inputs the licensee used and the NRC staff evaluated are presented in the attached Table 5. The licensee's analysis results show the radiological consequences of the SGTR, assuming either a pre-existing iodine spike or accident-initiated iodine spike, remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the coolant activity source terms based on the licensee's information and found the licensee's coolant source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated SGTR.

3.5.2.6 Small-Break Loss-of-Coolant Accident (SBLOCA)

The licensee performed an analysis of the potential consequences of a SBLOCA. In their assessment, they assumed that a break in the RCS occurred that resulted in substantial fuel damage in the reactor core, but the release was small enough that the containment spray system would not be actuated by high containment pressure. The licensee assumed that the fission gases in the gaps of all the fuel rods in the core were released to the RCS water. Activity released to the containment through the break is assumed to be released to the environment through the containment leaking at its design leak rate. The analysis assumed that the iodine in containment was 4.85% elemental, 0.15% organic, and 95% particulate. The licensee's analysis credited removal of particulate iodine in the containment atmosphere through sedimentation. This assumption was previously found acceptable in Amendment No. 211, which implemented an AST at IP2.

Activity is also released to the environment by way of primary-to-secondary SG tube leakage at the TS limit of 150 gpd/SG and steaming from the SG's secondary side. The activity in the SGs is released to the environment through steaming, with an assumed partitioning factor of 0.01. The iodine chemical form released to the atmosphere from the secondary system was assumed to be 97% elemental iodine and 3% organic iodine. The steaming releases were assumed to end when the RCS pressure drops below the secondary pressure at 2 hours.

The low pressurizer pressure SI setpoint would be reached 61 seconds after the event starts. The SI signal causes the control room HVAC system to enter the emergency filtration mode. In the REA radiological consequences analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation, 3 minutes after the event.

Because RG 1.183 does not give specific guidance on analysis of the SBLOCA, the NRC staff considered applicable guidance on the rod ejection accident, which is analogous to a very small LOCA. The NRC staff finds that the licensee's analysis of the SBLOCA follows the guidance in RG 1.183. The SBLOCA assumptions and inputs the licensee used, and the NRC staff

evaluated, are presented in the attached Table 6. The licensee's analysis results show the radiological consequences of the SBLOCA remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the activity source terms based on the licensee's information and found the licensee's source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated SBLOCA.

3.5.2.7 Large-Break Loss-of-Coolant Accident (LBLOCA)

The licensee evaluated the radiological consequences of an LBLOCA assuming the proposed increased core thermal power. The licensee's analysis used the analytical methods and assumptions outlined in the RG 1.183. The LBLOCA postulates that a break occurs in the RCS such that cooling water cannot be supplied to the core, and the core melts. The analysis considered the release of radioactivity from the damaged core to the containment, then to the environment through design basis containment leakage. The analysis also assumed that once external recirculation by the ECCS is established, radioactivity in the sump solution can be released to the environment through leakage from ECCS equipment in the auxiliary building.

The licensee used a source term for the LBLOCA following the guidance in RG 1.183, Regulatory Position 3, Table 2 with regard to the timing and magnitude of the core release. The activity inventory in the core was based on operation at 102% of the proposed uprated core power of 3216 MWt to give an analysis assumption of 3280.3 MWt. The iodine in containment was assumed to be 4.85% elemental, 0.15% organic, and 95% particulate. For the analysis of release from the ECCS, the iodine activity that became airborne from the leakage was modeled as 97% elemental and 3% organic. For the containment leakage analysis, all activity released from the core was assumed to be released to the containment atmosphere, where it was subject to removal by sprays, sedimentation, radioactive decay or leakage from the containment. For the ECCS leakage analysis, all iodine released from the core was assumed to instantaneously and homogeneously mix in the sump solution with no removal processes except radioactive decay or leakage from the ECCS.

The licensee's analysis assumed that containment sprays remove particulates and elemental iodine from the containment atmosphere. Particulates are also assumed to be removed by sedimentation. One train of the containment spray system was assumed to operate following the onset of the LBLOCA. The licensee used the methodology of SRP 6.5.2, "Containment Spray as a Fission Product Cleanup System," to determine the coefficients for spray removal of elemental and particulate iodine to be used in the radiological consequences analysis. Injection spray was assumed to begin after a 60-second startup delay. When the RWST drains to a predetermined level, the reactor operators switch the ECCS system to sump recirculation to provide a source of fluid for the sprays. The licensee's analysis assumed that the switchover to recirculation occurred at 40 minutes. At this time, spray removal decreases. The licensee modeled spray operation until 3.4 hours after the onset of the accident.

During spray operation, the licensee did not take credit for sedimentation removal of particulate iodine in the sprayed region of containment. After the sprays have terminated at 3.4 hours, sedimentation removal was credited in the sprayed region of containment. Sedimentation removal was assumed in the unsprayed region of containment from the onset of the accident. The licensee assumed a sedimentation removal coefficient of 0.1 per hour, as previously found acceptable by the NRC staff in the SE for Amendment No. 211.

The licensee assumed that external ECCS recirculation is established at 6.5 hours after onset of the LBLOCA. Prior to this, there is no potential for leakage outside the containment from the ECCS. The licensee modeled the ECCS leakage as being twice the TS allowable leakage value, which is consistent with RG 1.183. The leakage continues for 30 days and goes into the auxiliary building, and is assumed released to the environment without credit for filtration or holdup in the building. The licensee modeled the fraction of leakage that becomes airborne as time-dependent, using a methodology previously reviewed by the NRC staff for the implementation of an AST at IP2. In the SE for Amendment No. 211, the NRC staff found the constant enthalpy method for determining the airborne fraction acceptable. The licensee's calculation for the stretch power uprate used this same methodology, but used updated analysis assumptions to account for the proposed uprated power. The NRC staff reviewed the previously submitted proprietary and non-proprietary documents on the methodology used to calculate the airborne fraction of ECCS leakage which were provided for the review of Amendment No. 211. The NRC staff found no limitations on the methodology that would preclude its use for an uprated power. The NRC staff finds the continued use of the constant enthalpy method at IP2 for the calculation of the ECCS leakage airborne fraction to be acceptable.

The low pressurizer pressure SI setpoint would be reached shortly after the event starts. The SI signal causes the control room HVAC system to enter the emergency filtration mode. In the LBLOCA radiological consequences analysis, the licensee assumed the control room HVAC would enter the emergency mode of operation 1 minute after the event.

The NRC staff finds that the licensee's analysis of the LBLOCA follows the guidance in RG 1.183. The LBLOCA assumptions and inputs the licensee used, and the NRC staff evaluated, are presented in attached Table 7. The licensee's analysis results show the radiological consequences of the LBLOCA remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the core activity source terms based on the licensee's information and found the licensee's source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated LBLOCA.

3.5.2.8 Fuel-Handling Accident (FHA)

The FHA postulates that a fuel assembly is dropped and damaged during refueling operations. The licensee performed one analysis with assumptions selected so that the results would be

bounding for the accident occurring either inside the containment or in the fuel-handling building. The licensee's analysis assumed that radioactivity released from the damaged assembly would be released to the outside atmosphere through the containment purge system if the FHA happened inside containment, or through the fuel pit ventilation system if the FHA happened in the fuel-handling building. All radioactivity released from the water above the damaged fuel was assumed to be released to the atmosphere within 2 hours, using a linear release model. The licensee's analysis did not take credit for isolating the containment for the FHA in containment, or for operating the spent fuel pit ventilation system for the FHA in the fuel-handling building.

Because the licensee could not show that all fuel would meet the burnup conditions in footnote 11 in RG 1.183 to be able to use the gap activity fractions, the analysis used gap fractions of 12% for 1-131, 30% for Kr-85 and 10% for all other nuclides. These fractions are taken from RG 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling Water and Pressurized Water Reactors," and NUREG/CR-5009, "Assessment of the Use of Extended Burnup Fuel in Light Water Reactors." The licensee's analysis assumed that all the gap activity within all the fuel rods of the damaged assembly is released. The assembly inventory was based on the assumption that the assembly had been operated at 1.7 times the core average power, and the assembly had last been in an operating core 84 hours before the accident. The licensee's analysis assumed an effective iodine decontamination factor of 200 for the water above the damaged fuel. The cesium released from the damaged fuel is assumed to remain in a nonvolatile form and is not released from the water pool.

The licensee assumed that the control room HVAC system would remain in normal operation mode throughout the event.

The NRC staff finds that the licensee's analysis of the FHA follows the guidance in RG 1.183. The FHA assumptions and inputs the licensee used, and the NRC staff evaluated, are presented in attached Table 8. The licensee's analysis results show the radiological consequences of the FHA remain within the regulatory dose acceptance criteria within RG 1.183, both for persons offsite and operators in the control room. The licensee's analysis results are presented in Table 1.

The NRC staff evaluated the licensee's analyses against RG 1.183 and found the methodology, inputs and assumptions to be in accordance with the guidance. The NRC staff independently calculated the activity source terms based on the licensee's information and found the licensee's source terms acceptable. The NRC staff performed independent dose analyses using the licensee's assumptions, and confirmed the licensee's results. Based on the preceding discussion, the NRC staff finds acceptable the licensee's analysis of the impact of the proposed changes on the radiological consequences of the postulated FHA.

3.5.2.9 Control Room Habitability

Entergy considered the dose to control room operators due to these DBAs. In their analyses, the licensee assumed that the control room unfiltered inleakage was 700 cfm. This value is part of the IP2 current licensing bases and is based on integrated leakage testing of the control room envelope. On June 12, 2003, the NRC staff issued Generic Letter (GL) 2003-01, "Control Room Habitability." This GL discusses NRC staff concerns regarding the reliability of current

surveillance testing to identify and quantify control room inleakage, and requests licensees to confirm the most limiting unfiltered inleakage into their control room envelope. Entergy was required by the GL to respond to the information request within 180 days of its issue. The IP2 response was submitted to the NRC by letter dated November 25, 2003, but the NRC staff has not completed review of the response. The NRC staff has determined that there is reasonable assurance that the IP2 control room will be habitable during a DBA with the plant operating at the uprated power, and this amendment may be approved prior to the NRC staff's review of the Entergy response to the GL. The NRC staff bases this determination on the dose analyses provided and the verification of the control room unfiltered inleakage assumption through tracer gas testing. The NRC staff's approval of this amendment does not relieve Entergy of addressing the information requests in GL 2003-01 and does not imply that the NRC staff would necessarily find the analysis in this amendment acceptable as a response to information request 1(a) in GL 2003-01.

3.5.2.10 Analysis of Other Accidents

The licensee also evaluated the impact of the uprated power on three non-DBA dose analyses. These were the waste gas decay tank (GDT) rupture, volume control tank (VCT) rupture and holdup tank (HT) rupture. In its June 16, 2004, response to NRC staff's RAI, the licensee reported dose results for these non-DBA accidents that show the offsite consequences of these accidents remain within the current IP2 licensing basis dose criterion of 0.5 rem whole body or its equivalent to any part of the body, as defined in RG 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants." Entergy's analyses of these non-DBA accidents assumed source terms in these tanks based on operation at the uprated power and followed the guidance in RG 1.26 on analysis assumptions and methodology. Based on this, the NRC staff finds the licensee's analyses of these accidents to be acceptable. The licensee's analysis results show that the offsite radiological consequences of the failure of the GDT, VCT, or HT remain within 0.5 rem whole body or its equivalent to any part of the body. The licensee's analysis results also show that the radiological consequences in the control room of these accidents remains within the GDC-19 dose limits of 5 rem whole body, or its equivalent to any part of the body for the duration of the accident. Based on the above, the NRC staff finds the proposed changes acceptable with respect to the radiological consequences of these accidents.

3.5.3 Summary

As described above, the NRC staff reviewed the assumptions, inputs, and methods used by Entergy to assess the radiological impacts of a 3.26% increase in core power at IP2. The NRC staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance. The NRC staff compared the doses estimated by the licensee to the applicable criteria. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and control room doses will continue to comply with these criteria. Therefore, the proposed power uprate is acceptable with regard to the radiological consequences of postulated DBAs.

3.6 Materials and Chemical Engineering

3.6.1 Reactor Vessel Material Surveillance Program

3.6.1.1 Regulatory Evaluation

The reactor vessel (RV) material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Appendix H to 10 CFR Part 50 provides the NRC staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focused on the effects of the proposed SPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on: (1) GDC-14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating failure; (2) GDC-31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in SRP Section 5.3.1.

3.6.1.2 Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RV materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. 10 CFR Part 50, Appendix H, invokes, by reference, the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." ASTM Standard Practice E185 provides guidelines for designing and implementing the RV materials surveillance programs for operating light-water reactors, including guidelines for determining RV surveillance capsule withdrawal schedules based on the vessel material predicted transition temperature shifts (ΔRT_{NDT}). The surveillance capsule withdrawal schedule is prepared in terms of EFPY of plant operation with a projected design life of 32 EFPY. Entergy is applying the 1982 Version of ASTM E185 as its basis for implementing the IP2 RV materials surveillance program.

The licensee discussed the impact of the 3.26% SPU on the RV material surveillance program in Section 5.1.2.1 of the January 29, 2004, application, and stated that the revised SPU fluence projections have been used in the assessment of the current withdrawal schedule for IP2. This calculation determined that the maximum ΔRT_{NDT} using the SPU fluences corresponding to 3216MWt for IP2 at 32 EFPYs is greater than 200 EF, and does not change the required number of capsules to be withdrawn from the IP2 reactor in the current RV materials surveillance program withdrawal schedule. However, in the licensee's submittal there was an increase in predicted fluence value, which considered the power distributions for Cycles 17, 18, and 19. In a letter dated June 16, 2004, the licensee stated that WCAP-15629, "Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation, Revision 1," dated December 2001, which was reviewed and approved by the NRC staff on February 15, 2004, incorporated the SPU fluence prior to the SPU license amendment review. As a result, the specific analysis performed for the SPU only had to

incorporate the effect of actual thermal and power history data from the additional operating cycles attained since WCAP-15629, Revision 1 was originally issued. The new applicability date was 0.3 EFPY different, which the licensee determined to be negligible.

ASTM E185-82 requires 5 capsules to be withdrawn when a ΔRT_{NDT} of greater than 200 EF is predicted. The IP2 RV materials surveillance program withdrawal schedule in Table 4.5.2 of Revision 17 of the IP2 UFSAR shows that IP2 has a withdrawal schedule of 5 capsules with a total of 8 capsules in the IP2 RV materials surveillance program. The first capsule was withdrawn in 1976 (end of cycle 1) per ASTM E185-73, the second capsule was withdrawn in 1978 (end of cycle 2) per ASTM E185-73, the third capsule was withdrawn in 1982 (end of cycle 5) per ASTM E185-79, and the fourth capsule was withdrawn in 1987 (end of cycle 8) per ASTM E185-79. The fifth capsule will be withdrawn at the end of cycle 16. The remaining three capsules will remain in the RV as “standby” capsules.

3.6.1.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the RV surveillance capsule withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence on the IP2 RV materials surveillance program withdrawal schedule. The NRC staff further concludes that the RV capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR Part 50, Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the RV material surveillance program.

3.6.2 Upper-Shelf Energy, Pressure-Temperature Limits, and Fracture Integrity Evaluation

3.6.2.1 Regulatory Evaluation

Appendix G to 10 CFR Part 50 provides fracture toughness requirements for ferritic materials (low alloy steel or carbon steel) in the RCPB, including requirements on the upper shelf energy (USE) values used for assessing the remaining safety margins of the RV materials against ductile tearing, and requirements for calculating pressure-temperature (P-T) limits for the plant. 10 CFR Part 50, Appendix G identifies that RCPB materials must satisfy the criteria in Appendix G of ASME Code, Section XI to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests.

The NRC’s acceptance criteria are based on: (1) GDC-14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of Appendix G to 10 CFR Part 50. Specific review criteria are contained in SRP Section 5.3.2.

3.6.2.2 Technical Evaluation

USE Value Calculations

Appendix G to 10 CFR Part 50 provides the NRC staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of the ASME Code. The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials, and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H, RV materials surveillance program.

The licensee discussed the impact of the 3.26% SPU on the USE values for the RV beltline materials in Section 5.1.2.5 of the SPU analysis report. In this section, the licensee stated that all RV beltline materials have a USE greater than 50 ft-lb through the end-of-lifetime (EOL) as required by Appendix G to 10 CFR Part 50. Additionally, the licensee stated that Table 5.1-3 of the SPU safety analysis report provides the predicted USE values for IP2 based on the bounding SPU fluence values documented in WCAP-15629, Revision 1, for all materials in the beltline region of the IP2 RV. In WCAP-15629, Revision 1, vessel fluence projections were calculated for 3216 MWt, which bounds the proposed SPU.

The NRC staff performed an independent calculation of the EOL USE values for the IP2 RV beltline materials using the limiting 32 EFPY neutron fluence value for the one-quarter of the vessel wall thickness (1/4T) location of the vessel as documented in the SPU safety analysis report for the SPU conditions. The NRC staff determined that, under the SPU conditions, the Intermediate Shell Plate B-2002-3 is the limiting beltline material for the USE value and calculated a 50.3 ft-lb USE value for this material at 32 EFPY. This value is in agreement with the limiting 32 EFPY USE value cited by the licensee for the SPU and is in agreement with the requirements in 10 CFR Part 50, Appendix G, for operating reactors. Therefore, the NRC staff concludes that the beltline materials in the IP2 RV will have acceptable USE values under the SPU conditions for the unit.

P-T Limit Calculations

Section IV.A.2 of Appendix G to 10 CFR Part 50 requires that the P-T limits for operating reactors be at least as conservative as those that would be generated if the methods of calculation in the ASME Code, Section XI, Appendix G, were used to calculate the P-T limits. The rule also requires that the P-T limit calculations account for the effects of neutron irradiation on the P-T limit values for the RV beltline materials, and to incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H, RV materials surveillance program.

IP2's current pressure temperature limits report (PTLR) was reviewed and approved by the NRC staff in a February 15, 2004, letter. The basis for the PTLR is contained in WCAP-15629. The licensee stated in their submittal that the projected neutron fluence values for the SPU had

increased a small amount, but had no effect on the applicability date of the existing P-T limit curves. In a letter dated June 16, 2004, IP2 submitted a reply to the NRC staff's request for additional information, which stated that the specific analysis for the vessel fluence performed for the SPU had to incorporate only the effect of actual thermal and power history data from the additional operating cycles attained since WCAP-15629 Revision 1 was issued. The licensee determined this effect by calculating a new applicability date of an additional 0.3 EFPY, and found it to be negligible. The NRC staff determined this small increase in vessel fluence and EFPYs for the proposed SPU to have a negligible impact on the existing P-T limit curves.

Fracture Integrity Evaluation

Appendix G to 10 CFR Part 50 specifies fracture toughness requirements for ferritic materials of pressure-retaining components of the reactor coolant pressure boundary. 10 CFR Part 50, Appendix G, specifies that pressure-retaining components of the reactor coolant pressure boundary that are made of ferritic materials must meet the requirements of Appendix G of Section XI of the ASME Code. Appendix G of Section XI of the ASME Code provides requirements for obtaining the allowable loadings for ferritic pressure retaining components. These requirements are based on the principles of linear elastic fracture mechanics. For section thicknesses of 4 inches to 12 inches, a maximum postulated 1/4T flaw depth is evaluated. For section thicknesses less than 4 inches, a postulated 1 inch deep flaw is evaluated. Appendix G of Section XI of the ASME Code indicates that smaller defect sizes may be utilized on an individual case basis if a smaller size of a maximum postulated defect can be ensured. Appendix G of Section XI of the ASME Code references Weld Research Council Bulletin 175 (WRCB-175) and indicates Paragragh 5(c)(2) of the bulletin provides procedures for considering smaller postulated flaws. Paragraph 5(c)(2) of WRCB-175 indicates "examination methods must be able to assure [detection of] smaller defects," if smaller flaws than those specified in Appendix G of Section XI of the ASME Code are to be utilized in the analyses.

The licensee discussed the effects of the SPU on the fracture integrity of ferritic Class 1 components, specifically the RV and pressurizer, in Section 5.9 of the SPU analysis report. The stresses in the RV and the pressurizer for the SPU were evaluated under the conditions specified in Sections 5.1 and 5.7 of the SPU analysis report. The original design transients were updated in Section 3 of the SPU analysis report and were included in the fracture integrity evaluation of Section 5.9 of the SPU analysis report.

In Table 5.9-3 of the licensee's submittal, the licensee provided the postulated flaw depth values and the ratio of the calculated stress intensity factor (K_I) to the reference fracture toughness (K_{IR}) for the RV components. Table 5.9-3 of the licensee's submittal indicates all RV components will meet the requirements of Appendix G of the ASME Code except for the RV outlet nozzle-to-shell region. The licensee used a postulated flaw depth of 1/5T (2.15-inches) instead of 1/4T for the RV outlet nozzle-to-shell region.

In a letter dated June 16, 2004, the licensee provided a generic analysis that justified the smaller flaw depth of 1/5T based on the data provided in an ASME Code technical basis document from the Proceedings of ASME 2001 Pressure Vessels and Piping Conference, Atlanta, GA, "Technical Basis for Elimination of Reactor Vessel Nozzle Inner Radius Inspections," W.H. Bamford, et. al, July 2001. This data indicates that the probability of detection (POD) of a flaw with a depth of equal to 0.5-inch is approximately 99.9 percent. In a

letter dated August 12, 2004, the licensee provided additional information to confirm that non-destructive inspection techniques used for previous inspections of the RV outlet nozzle-to-shell welds were consistent with non-destructive inspection techniques used in the technical basis document. The licensee also stated that there were no flaws detected on the RV outlet nozzle-to-shell weld using these non-destructive techniques during their most recent volumetric [ultrasonic] exam conducted on March 1995. The staff concurs that the POD for detecting a 1/5T flaw is very high in this type of material and with the type of ultrasonic examination techniques applied in these locations. Therefore, the staff concludes that the use of the 1/5T flaw size for the RV outlet nozzle-to-shell region in the in the ASME Code Appendix G vessel integrity analysis is justified.

In Table 5.9-5 of the January 29, 2004, application, the licensee provided postulated flaw depth values and the ratio of the K_I to the K_{IR} for pressurizer components. Table 5.9-5 of the licensee's submittal indicates all pressurizer components will meet the requirements of Appendix G of the ASME Code except for the pressurizer safety and relief nozzle and the pressurizer upper shell. The licensee used a postulated flaw depth of 0.50-inch for the pressurizer safety and relief nozzle and a postulated flaw depth of 0.15-inch for the pressurizer upper shell. The governing transient for the upper shell region during SPU conditions is inadvertent auxiliary spray.

The staff requested that the licensee either demonstrate the examinations methods for the pressurizer safety and relief nozzle and the pressurizer upper shell were capable of detecting the flaw sizes postulated or provide a revised analysis that utilzed the flaws sizes specified in Appendix G of Section XI of the ASME Code. In response to the staff's request, the licensee provided additional fracture mechanics analysis to demonstrate that the pressurizer safety and relief nozzles and the pressurizer upper shell would meet the requirements of Appendix G of the ASME Code during SPU conditions. The revised fracture mechanics analysis is documented in the Entergy response to NRC Item 6 in the licensee's letter dated September 24, 2004. The licensee indicates:

> The fracture mechanics analysis for the IP2 pressurizer upper shell has been revised to consider an updated technical evaluation of spray characteristic of the inadvertent spray transient based on tests and analytical solutions that showed the spray droplet envelope remains well removed from the pressurizer wall at pressure levels above 1030 psia. This fracture mechanics analysis also included modified through-wall stresses for the governing location. Since the section thickness for the upper shell is 4.1875 inches, a 1/4T (1.05 inches) deep defect was conservatively postulated per Paragraph G-2120 of the ASME Code, Appendix G 1998 Edition. The analysis for the safety and relief nozzle was also revised using modified through-wall stresses. A defect of 1 inch was postulated since the section thickness of the governing location for the pressurizer safety and relief nozzle is less than 4 inches. The results show that the maximum stress intensity factor K_I for the governing transient is less than K_{IR}. Therefore, it is concluded that the IP2 pressurizer upper shell and safety & relief nozzle are in compliance with the ASME Code, Section III, Appendix G 1998 Edition requirements for the SPU conditions.

Since the revised analysis meets the fracture requirements of Appendix G of the ASME Code, pressurizer fracture integrity is ensured during SPU conditions.

3.6.2.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the USE values for the RV beltline materials and P-T limits for the plant. The staff concludes that the licensee has adequately addressed changes in neutron fluence and their impacts on the USE values for the IP2 RV and P-T limits for the plant. The staff concludes that the IP2 RV beltline materials will continue to have acceptable USE, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operating license for the facility. The NRC staff concludes that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed SPU conditions. The NRC staff also concludes that the licensee has adequately addressed fracture integrity evaluations for ferritic pressure-retaining components of the reactor coolant pressure boundary. Based on this assessment, the NRC staff concludes that the IP2 facility will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU.

3.6.3 Pressurized Thermal Shock

3.6.3.1 Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided for supporting reactor operation. The NRC staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The NRC staff's review covered the PTS methodology and the calculations for the reference temperature, RT_{PTS}, at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on: (1) GDC-14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC-31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) 10 CFR 50.61, which sets fracture toughness criteria for protection against PTS events. Specific review criteria are contained in SRP Section 5.3.2.

3.6.3.2 Technical Evaluation

The NRC staff has established requirements in 10 CFR 50.61 that are designed to protect the PWR RVs against the consequences of PTS events. The rule requires licensees owning PWRs to calculate a nil-ductility reference temperature at EOL fluence (as defined in 10 CFR 50.61) for each base metal and weld material in the RV that are made from carbon or low-alloy steel materials. The rule also requires the RT_{PTS} values to be maintained below the PTS screening criteria throughout the serviceable life of the facilities. The rule's screening criteria are 270 EF for axial weld materials and base metal materials and 300 EF for circumferential weld materials.

10 CFR 50.61 provides a required methodology for calculating these RT_{PTS} values, which are based on the calculation methods in RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials." For materials in the beltline region of the vessel, the rule requires that the calculations account for the effects of neutron irradiation on the RT_{PTS} values for the materials

and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RV materials surveillance program.

The licensee discussed the impact of the SPU on the IP2 PTS assessment in Section 5.1.2.1.4 of the SPU analysis report. In Section 5.1.2.1.4 of the SPU analysis report, the licensee references WCAP-15629, Revision 1, as the supporting document for the PTS assessment for SPU conditions. In WCAP-15629, Revision 1, the licensee stated that the PTS assessment for the IP2 RV under the uprated conditions is limited by the intermediate to lower shell girth weld (Heat 34B009) and that this material has a limiting RT_{PTS} value of 246 EF at EOL (32 EFPY). WCAP-15629, Revision1 also indicates the Intermediate shell plate (B-2002-3) has a RT_{PTS} value of 244EF at EOL, which is 2EF less than the RT_{PTS} value of the intermediate to lower shell girth weld.

The NRC staff performed an independent calculation of the EOL RT_{PTS} values for the IP2 RV beltline materials using the limiting 32 EFPY neutron fluence value for the clad-metal interface location of the vessel at SPU conditions. The NRC staff determined that, under the SPU conditions, the intermediate to lower shell girth weld is the limiting 32 EFPY beltline material for PTS. The NRC staff calculated an RT_{PTS} value of 246EF for this material at 32 EFPY under SPU conditions. Both the RT_{PTS} values cited by the licensee and the NRC staff were consistent and are well within the rule's PTS screening criteria established for base metal materials. The NRC staff therefore concludes that the beltline materials in the IP2 RV will have acceptable safety margins against the consequences of PTS events under the SPU conditions, as is mandated by the PTS requirements of 10 CFR 50.61.

3.6.3.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the PTS for the plant, and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on PTS. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDC-14, GDC-31, and 10 CFR 50.61 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to PTS.

3.6.4 Reactor Internal and Core Support Materials

3.6.4.1 Regulatory Evaluation

The RV internals and core supports include SSCs that perform safety functions, and whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the RCS). The NRC staff's reviews covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for RV internal and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of RV internals and core supports. Specific review criteria are contained in SRP Section 4.5.2.

3.6.4.2 Technical Evaluation

The licensee discussed the impact of the SPU on the structural integrity of the IP2 RV internal components in Section 5.2 of the SPU analysis report. The licensee additionally discussed the effect of changes due to the SPU in their evaluation of RV internals for loading due to structure deadweight, temperature differences, flow loads, fuel assembly pre-load, control rod assembly dynamic loads, vibratory loads, and earthquake accelerations. The evaluations were performed in accordance with ASME Code, Section III, 1965 Edition with Winter 1965 Addenda.

The licensee provided information regarding changes to operating temperature, pressure, flow rates, and neutron fluences resulting from the SPU. The licensee's evaluation indicate that the SPU RCS conditions will not adversely affect the response of RV internals systems and components due to seismic or LOCA excitations. Also, these evaluations demonstrated the IP2 RV internals assemblies will remain stable and seated at the SPU RCS conditions.

The licensee provided information regarding the design core bypass flow with the thimble plugging devices removed under SPU conditions. The licensee's subsequent assessment concluded that the total design core bypass flow with the thimble plugging devices removed was 6.5%. Since this is consistent with original design conditions as shown in Table 2.1-1 of the SPU safety analysis, the effect of the SPU on RV internals is bounded by the original design conditions.

3.6.4.3 Conclusion

The NRC staff concludes that the licensee has demonstrated that the RV internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC-1 and 10 CFR 50.55a following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to RV internal and core support materials.

3.6.5 RCS Potential Material Degradation Assessment

This section of the licensee's submittal summarizes the evaluations and results of an assessment of the potential materials degradation issues arising from the effects of the IP2 proposed power uprate on the performance of primary component materials.

The primary concern from the proposed power uprate is the potential effect of changes in the RCS chemistry (impurities) and pH conditions, and the power uprate service temperatures on the integrity of RCS component materials during service. These concerns include general corrosion (wastage) and stress corrosion cracking (SCC) of system materials, fuels corrosion, and primary water stress corrosion cracking (PWSCC) of nickel base alloys.

A review of Table 5.10.1 of the January 29, 2004, application indicated that the following changes in the RCS will occur during operations after the power uprate is implemented:

- The maximum increase in the reactor vessel upper head temperature due to the proposed power uprate is estimated at 3.88 EF.

- The maximum increase in the hot leg nozzle temperature due to the proposed power uprate is estimated at 1.50 EF

The licensee evaluated the effect of the proposed service conditions on the performance of RCS materials as follows.

3.6.5.1 Austenitic Stainless Steels

The two degradation mechanisms that are applicable to austenitic stainless steels in the reactor coolant environment are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Sensitized microstructure, susceptible materials, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The chemistry changes resulting from uprating do not involve introduction of any of these contributors so that no effect on material degradation is expected in the stainless steel components as a result of the power uprate.

The licensee stated that the proposed lithium, boron and pH management program meets the Electric Power Research Institute (EPRI) chemistry guidelines. Since these guidelines are specifically designed to prevent fuel cladding corrosion effects such as fuel deposit build-up and Alloy 600 PWSCC, there will be no adverse effect on fuel cladding corrosion as a result of the proposed power uprate. Experience with operating plants as well as with the guidelines provided by EPRI suggest that increasing initial lithium concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values between 6.9 to 7.4 has not produced any undesirable material integrity issues. IP2 plans to maintain lithium levels at 3.5 ppm or less and thus no adverse effects from this aspect on the power uprate is expected to occur.

3.6.5.2 Alloy 600/82/182 Components

The most significant factor that influences the PWSCC of Alloy 600/82/182 components is the service temperature. The two most significant Alloy 600/82/182 components that are bounding to the PWSCC susceptibility are the reactor vessel head penetrations (RVHP) and the hot leg nozzle welds. As stated above, Table 5.10 estimates the maximum increase in the reactor vessel upper head temperature to be 3.88 EF and the maximum increase in the hot leg nozzle temperature to be 1.50 EF.

The industry experience over the past decade showed that the PWSCC susceptibility of the Alloy 600/82/182 outer-most circle RVHPs is considered bounding to other Alloy 600 primary component locations due to the presence of high residual stresses and service temperatures at those penetration locations. The RV upper head best-estimate mean fluid maximum service temperature is considered to be the RVHP temperature for the purpose of the current evaluation. The licensee calculated the maximum change in the PWSCC susceptibility value of the highest susceptible (outer circle) penetration using the maximum change in RVHP temperature (3.88 EF). The calculations showed an estimated 31% increase in RVHP penetration susceptibility to PWSCC as a result of the power uprate. The absolute susceptibility of these locations was estimated to be very low (-10^{-11}).

The licensee also evaluated the maximum change in the hot leg nozzle weld PWSCC susceptibility due to the power uprate using values provided in Table 5.10-1 (1.5 EF). The

licensee calculated the maximum change in the PWSCC susceptibility value of the highest susceptible hot leg nozzle weld using the maximum change in RVHP temperature (1.5 EF). The calculations showed an estimated 12-percent increase in the hot leg nozzle weld susceptibility to PWSCC as a result of the power uprate. The absolute susceptibility of these locations was also estimated to be very low (- 10^{-11}).

The licensee concluded that no appreciable material degradation issues were identified with the RCS materials due to the power uprate at IP2 because the lithium concentration will be limited to 3.5 ppm and the increase in PWSCC susceptibilities of Alloy 600 RVHP and Alloy 82/182 hot leg nozzle weld locations (31% and 12%, respectively) is not considered significant since the absolute susceptibility of these locations is estimated to be very low (approximately 10^{-11}).

3.6.5.3 RCS Potential Material Degradation Assessment Conclusion

The staff reviewed the information provided by the licensee and found it acceptable. The staff, therefore, finds that the minor increase in temperature during power uprate conditions at IP2 has little or no effect on RCS component materials. The staff agrees with the licensee's conclusion that the above listed materials will not be adversely effected in a significant manner due to the power uprate. Based upon the results of its review, the staff concludes that the licensee has adequately evaluated the effects of power uprate on the integrity of RCS materials. The NRC staff further concludes that the licensee has demonstrated that the RCS materials will continue to be acceptable following implementation of the proposed power uprate and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to RCS materials.

3.6.6 Application of Leak-Before-Break (LBB) Methodology

The licensee stated that the current structural design basis of IP2 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. Section 5.4.2 of the January 29, 2004, application describes the analyses and evaluations performed to demonstrate that the elimination of these breaks continues to be justified at the operating conditions associated with the IP2 power uprate program.

According to the licensee, Westinghouse performed analyses for LBB of IP2 primary loop piping in 1986 and 1989. The results of the analyses were documented in WCAP-10977, Revision 2 and WCAP-10977, Supplement 1. Both WCAPs have been reviewed and approved by the NRC. Westinghouse also performed analyses in 2000 to support the Replacement Steam Generator (RSG) Program and performed an evaluation for the Snubber Reduction Program.

To support the IP2 power uprate program, the licensee updated the previous LBB analyses to address the proposed power uprate conditions. The primary loop piping dead weight, normal thermal expansion, safe shutdown earthquake (SSE), pressure loads, normal operating temperature and pressure under power uprate conditions were used in the evaluation. The recommendations and criteria included in SRP Section 3.6.3 were used in the evaluation. The evaluation showed that all the LBB recommended margins were satisfied for the power uprate conditions.

The LBB acceptance criteria and the recommended margins stated in SRP 3.6.3 are as follows:

- Margin of 10 on leak rate
- Margin of 2 on flaw size
- Margin on loads of 1 (using faulted load combinations by absolute summation method)

The evaluation results showed the following at all the critical locations: a margin of 10 exists between the calculated leak rate from the leakage flaw and leak detection capability of 1 gpm; a margin of 2 or more exists between the critical flaw size and the flaw size having a leak rate of 10 gpm (the leakage flaw); and a margin on loads of 1 exists using faulted load combinations by absolute summation method. The evaluation results showed that the LBB conclusions provided in WCAP-10977, including Supplement 1, and the analyses performed in 2000 to support the RSG Program as well as an evaluation for the Snubber Reduction Program for IP2 remain unchanged under power uprate conditions.

The licensee determined that the LBB acceptance criteria are satisfied for the IP2 primary loop piping under power uprate conditions. All the recommended margins are satisfied and the conclusions shown in WCAP-10977, including Supplement 1, and the analyses performed in 2000 to support the RSG Program as well as an evaluation for the Snubber Reduction Program remain valid. Therefore, the licensee concluded that the dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis of IP2 at the power uprate conditions.

3.6.6.1 LBB Methodology Conclusion

The NRC staff reviewed the information submitted by the licensee concerning potential impact of the proposed IP2 power uprate on the acceptability of the LBB status of the RCS piping. The primary system pressure, primary system temperature, material properties, and design-basis SSE loadings are the parameters that could have a significant impact on the facility's LBB evaluation. However, the licensee has demonstrated that the LBB acceptance criteria and the recommended margins based on SRP Section 3.6.3 would be maintained under power uprate conditions at IP2. Therefore, the staff concludes that the changes to the LBB evaluation for this piping resulting from the proposed power uprate will not alter the staff's previous conclusions stated in WCAP-10977 and WCAP-10977, Supplement 1. The staff concludes that, per the provisions of 10 CFR Part 50, Appendix A, GDC-4, the dynamic effects from postulated breaks of the IP2 RCS piping may continue to be excluded from the licensing basis of the facility for post-power uprate conditions. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed power uprate and that lines for which the licensee credits LBB will continue to meet the requirements of GDC-4. Therefore, the NRC staff finds the proposed power uprate acceptable with respect to LBB.

3.6.7 Chemical Volume and Control System (CVCS)

The CVCS consists of the regenerative, non-regenerative, excess letdown, and seal water heat exchangers, and the charging, letdown, and RCS makeup systems. The primary functions of the CVCS are to maintain RCS inventory and control RCS chemistry. Other RCS support functions include serving as a part of the RCS pressure boundary, aiding in removing

contaminant, providing auxiliary pressurizer spray, and providing for RCP seal bleedoff flow. The licensee examined the effect of operation under SPU conditions on the CVCS.

With regard to the regenerative, non-regenerative, excess letdown, and seal water heat exchangers, the licensee stated their analysis showed that performance is either not affected or is only slightly decreased, thereby resulting in negligible effects on heat exchanger performance under SPU conditions.

With regard to the RCS makeup system, the licensee stated that, since the flow capacity performance of the RCS makeup system is independent of the change in RCS conditions resulting from the SPU conditions, the SPU does not affect the capability of the makeup system to perform these system functions. The licensee also stated that the SPU is expected to have a small effect on the boration requirements that must be provided by the CVCS, and that the maximum expected RCS boron concentrations are within the capability of the CVCS.

With regard to the letdown system, the letdown flow path is routed inside containment such that there is adequate decay of N-16 before the letdown fluid leaves the containment building. The license stated that, since the change in letdown flow is negligible, this radiation protection feature of the CVCS is not affected by operation under SPU conditions.

The licensee increased the RWST temperature to provide additional margin for operations for SPU conditions. Therefore, the charging pump net positive suction head (NPSH) was evaluated. The licensee stated that the limiting NPSH temperature condition for the charging pumps occurs when they are aligned with the volume control tank. NPSH evaluation of the charging pump suction from the volume control tank was not affected by the RWST temperature change or the temperature of the volume control tank under SPU conditions. Therefore, the licensee stated that the NPSH bounds charging pump operation when pumping RWST water under SPU conditions.

With regard to primary chemistry control, the licensee evaluated the changes in plant parameters as a result of SPU conditions. In addition to the changes in the range of RCS T_{avg} and RCS T_{hot}, the RWST maximum boron concentration was increased, for SPU conditions, to 2600 ppm. The licensee stated that these operating conditions are well within the envelope of conditions used in developing the industry chemistry guidelines, and therefore no changes to primary chemistry control are required for the SPU.

On the basis of its review, the NRC staff concludes that the CVCS is adequate because all of the CVCS systems will operate within their capability limits under SPU conditions.

3.6.8 Steam Generator (SG) Blowdown System

The SG blowdown system (SGBS) is designed to extract blowdown water from the secondary side of the SGs as a means of removing particulates and dissolved solids to control water chemistry in the SGs. SG blowdown is collected from the steam generator and piped to the blowdown tank, which is vented to the atmosphere and drains to the service water system. The SGBS also provides samples of the secondary side water in the steam generator. These samples are used for monitoring water chemistry and for detecting the amount of radioactive primary coolant leakage through the steam generator tubes. The licensee examined the effect of higher feedwater flow rate due to SPU conditions on the SGBS.

The licensee stated that the maximum limits for blowdown flow are 66,300 lbm/hr (continuous normal flow), and 198,900 lbm/hr (for short periods of operation) per steam generator. The plant currently operates with a blowdown flow of 13,550 lbm/hr per steam generator. Based on SPU conditions, the feedwater flow would increase approximately 6% to 14,385 lbm/hr per steam generator. Therefore, the licensee concluded that the higher SPU blowdown flow was well within the maximum limits. The velocities in the blowdown lines increases from 3.8 ft/sec to 4.0 ft/sec at SPU conditions, which is considerably less than the system limits of 18.6 ft/sec (the normal blowdown limitation). The licensee stated that the steam generator steam outlet temperature and pressure change minimally under SPU conditions, and therefore do not affect the main steam safety valve setpoints nor the design pressure and temperature of the SGs.

On the basis of its review, the NRC staff finds that the SGBS is adequate because the flows, velocities, temperatures, and pressures associated with SPU conditions do not approach the capability limits for SGBS components or the steam generators, and the main steam safety valve setpoints are not affected by operation under SPU conditions.

3.6.9 SG Structural Integrity

The licensee performed evaluations of the following areas to address the operation of the IP2 SGs under SPU conditions: (1) thermal-hydraulic performance, (2) structural integrity of primary-side and secondary-side components, (3) tube repair hardware, (4) tube vibration and wear, and (5) tube integrity. The evaluations for SG structural integrity included a range of temperatures and pressures (if appropriate) for the component in question, and included SG plugging levels of 0% and 10%.

The licensee stated that the thermal-hydraulic evaluations, aided in some cases by several computer simulation codes, showed that SPU conditions: (1) have no significant effect on the secondary flow both in the downcomer and in the tube bundle; (2) cause a small but insignificant change in steam pressure; (3) cause a small increase in heat flux, which is not expected to result in tube wall dryout; (4) cause a small increase in moisture carryover but remains well below the 0.25% limit; (5) have no significant effect on damping factor, allowing the SG to operate in a hydro-dynamically stable manner; (6) cause an insignificant decrease in fluid inventory in the SG during operation, with no effect on operation; and (7) cause a small but insignificant change in secondary-side pressure drop, with no significant effect on feed system operation. The licensee stated that the thermal-hydraulic characteristics of the IP2 Model 44F SGs are within acceptable ranges for the SPU conditions with a tube plugging level below 10%.

With regard to structural integrity, the licensee stated that structural integrity evaluations for the SPU focused on the critical SG components; those which are the most highly stressed or have the highest cumulative fatigue usage for the current operating conditions. The evaluation included such primary-side components as the divider plate, tubesheet and shell junction, tube-to-tubesheet weld, and tubes. The evaluation also included such secondary-side components as the feedwater nozzle, secondary manway bolts/studs, and steam nozzle. The evaluation included the determination of scale factors, which took into account the pressure differential for the components listed.

The licensee stated that the structural integrity evaluations show that all analyzed components meet the ASME Code, Section III limits for a 40-year design life. However, in Table 5.6-2 of the submittal, “IP2 SPU Evaluation Summary Primary and Secondary Side Components,” the

licensee stated that the fatigue usage factor for secondary manway bolts is greater than 1.0 (the design limit is 1.0). The licensee was asked to provide additional information regarding a fatigue usage factor increase to a value greater than 1.0 for the secondary manway bolts under SPU conditions. The licensee responded that the IP2 replacement SGs use studs, not bolts. The licensee also stated that the fatigue usage factor for the secondary manway studs was significantly less than 1.0 and was therefore not compromised under SPU operating conditions.

With regard to primary-to-secondary side pressure differential, an analysis was performed to determine if the ASME Code limits on the Model 44F replacement SG design primary-to-secondary pressure differential are exceeded for any of the applicable transient conditions under SPU conditions. The licensee stated that the analysis indicated that the maximum normal and upset operating condition primary-to-secondary side differential pressures were both below the design limits. Therefore, the design pressure requirements of the ASME Code continue to be satisfied for operation under SPU conditions.

With regard to tube repair hardware, the licensee evaluated shop welded plugs, mechanical plugs, and a 40% tube wall undercut for operation under SPU conditions. In each case, the licensee stated that all repair hardware and undercut design satisfied ASME Code limits for operation under SPU conditions. However, no calculated data was presented to support the licensee's conclusions. The licensee was asked to provide additional information and calculations to show that all applicable stress and fatigue criteria for SPU conditions are satisfied for the shop welded plug. The licensee provided this information with additional clarification in a follow-up response, which showed that the weld between the shop weld plug and the tubesheet cladding satisfy all ASME Code Section III limits for a 40-year design life for operation under SPU conditions. The licensee was asked to provide additional information and calculations to show that the mechanical plug designs satisfy all applicable stress, retention, and fatigue criteria for SPU conditions. The licensee provided this information, which showed that the mechanical plug designs satisfy all ASME Code, Section III limits for a 40-year design life for operation under SPU conditions. The licensee was asked to provide additional information and calculations to show that all applicable stress and fatigue criteria for SPU conditions are satisfied for the tube undercut qualification. The licensee provided this information, which showed that the tube undercut qualification satisfies all ASME Code, Section III limits for a 40-year design life for operation under SPU conditions.

With regard to collar-cable stabilizer qualification and bare-cable stabilizer qualification, the licensee's evaluation showed that both stabilizers are acceptable for use in the SG tubes for operation under SPU conditions.

With regard to tube vibration and wear, the licensee evaluated the effect of the proposed SPU on the SG tubes based on the current design basis analysis, and included the changes in the thermal-hydraulic characteristics of the secondary-side of the SG resulting from the SPU. The effects of the SPU on potential tube failure were also considered. The licensee stated that their analysis of the tubes indicates that significant levels of tube vibration will not occur from fluid-elastic, vortex shedding, or turbulent mechanisms as a result of the proposed SPU, and that the projected level of tube wear as a result of vibration can be expected to remain small and not result in unacceptable wear. However, the licensee did find it necessary to plug several tubes due to anti-vibration bar (AVB) wear during the refueling outage (RFO) 15. The licensee was asked to provide additional information regarding the likely reasons for the wear in these tubes, and to discuss how increased vibrations due to SPU conditions might influence AVB

wear in tubes during future SPU operation. The licensee responded that the few tubes that did experience AVB wear were exposed to local conditions that lie outside of expected parameters, and therefore showed wear outside of predicted limits. The licensee also stated that most of the wear had already taken place in the tubes that were susceptible to “anomalous” wear. The licensee also stated that Westinghouse has greatly improved AVB wear resistance in their replacement SGs, and that an increase in wear of about 2-mils over the 40-year lifetime is expected in the tubes not susceptible to anomalous wear.

With regard to tube integrity, the licensee stated that enhanced materials and equipment design features of the replacement SGs have been shown to effectively reduce the potential for degradation. These include: (1) tubes made from thermally-treated Alloy 600, (2) hydraulically-expanded tubes in the tubesheet region, (3) quatrefoil-broached tube hole design with stainless steel tube support plate material, and (4) supplemental thermal treatment of rows 1 through 9 U-bends following bending. The licensee stated that these improvements in materials and design will help minimize the potential for SG tube degradation.

On the basis of its review, the staff finds that the SG structural integrity of the licensee’s SGs is adequate because the licensee’s evaluations of thermal-hydraulic performance, structural integrity of primary- and secondary-side components, tube repair hardware, tube vibration and wear, and tube integrity showed that the capability limits for the SG components are not affected by operation under SPU conditions.

3.6.10 Regulatory Guide 1.121 Analysis

RG 1.121 describes an acceptable method for establishing the limiting safe condition of SG tube degradation, beyond which tubes determined to be defective by the established inservice inspection should be removed from service. The level of acceptable degradation is referred to as the repair limit. The allowable repair limit, in accordance with RG 1.121, is obtained by incorporating into the resulting structural limit an allowance for continued growth of the flaw and an allowance for eddy current measurement uncertainty. In terms of the SPU, the structural limit and degradation rate are affected by parameters such as temperature change and differential pressure.

The licensee performed an analysis to determine structural limit for an assumed uniform thinning mode of degradation in both the axial and circumferential directions. The licensee provided a table of tube structural limits. However, the licensee did not conclude whether the revised structural limits support the tube repair limit currently in the TSs. In response to a request for additional information, the licensee responded that their analysis showed the existing tube repair limit of 40% remains appropriate under the proposed SPU conditions.

On the basis of its review, the NRC staff finds that the licensee’s analysis acceptable because it follows the guidance of RG 1.121.

3.6.11 Flow-Accelerated Corrosion Program

Flow accelerated corrosion (FAC) is a corrosion mechanism which occurs in systems that contain flowing single- or two-phase water. FAC results in wall thinning and possible failure of high energy carbon steel pipes in the power conversion system. Since failure of these pipes may result in undesirable challenges to the plant’s safety systems, licensees are required to

implement a program for prediction, inspection, and repair/replacement of the degraded components. The primary objective of the licensee's FAC Program is to maintain the process of FAC detection and monitoring in piping systems so that pipe wall thinning can be detected in time to prevent pipe ruptures.

The licensee did not identify any predictive FAC computer models in the submittal. In response to an RAI, the licensee stated that EPRI's CHECWORKS™ computer program is used for FAC predictions. Input to the model includes heat balance information, steam cycle data, water chemistry, flow operating time, and piping and component data to analytically determine which components are affected by FAC and need to be included in the inspection program. If the results of inspection indicate that the component is degraded beyond safety limits, it is repaired or replaced. Also, the results of the inspection are used to calibrate the CHECWORKS™ code to make its prediction more accurate. In response to an RAI regarding the highest expected wear rates due to operation under SPU conditions, the licensee stated that the impact of the SPU on the velocity, temperature, and wear rates of the components identified as having the greatest FAC susceptibility was less than 10%. The licensee also stated that the CHECWORKS™ computer model would be updated to determine the impact of the SPU, and appropriate actions would be taken to mitigate FAC.

On the basis of its review, the NRC staff finds that the licensee's FAC program is acceptable for operation under SPU conditions, because the effect of the SPU is very small and will be adequately controlled by the procedures in the FAC program.

3.6.12 Protective Coatings Program

In its application, the licensee did not provide any information on their protective coatings program. Therefore, in an RAI, the NRC staff asked the licensee to discuss: (1) how the qualification of Service Level 1 coatings are impacted by SPU temperature and pressure conditions; (2) whether the qualification parameters (e.g., temperature, pressure, etc.) for the Service Level 1 coatings will continue to be bounded by SPU/DBA conditions; and (3) actions that will be taken if the qualification for Service Level 1 coatings are not bounded by the SPU/DBA conditions. This is because coating failure could threaten performance of the ECCS sump after a LOCA. The licensee responded to each request by stating:

- The SPU temperature and pressure conditions are below or bounded by the DBA test parameters ANSI N101.2. Since the Service Level 1 coatings used at IP-2 have been tested to ANSI N-101.2, there is no impact from the SPU temperature and pressure conditions.

- The Service Level 1 coatings at IP-2 will continue to be bounded by the DBA parameters specified in ANSI N101.2.

- Considering that the Service Level 1 coatings have been tested to the DBA parameters specified in ANSI N101.2, which are more stringent than the SPU temperature and pressure conditions, no actions are required.

On the basis of its review, the staff finds that the licensee's protective coatings program is adequate, because the temperature and pressure limits continue to be bounded by the DBA

parameters, which are bounded by ANSI N101.2. Therefore, operation under SPU conditions will not impact the protective coatings.

3.7 Human Factors

3.7.1 Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to the potential impact on performance of plant operators and support personnel during normal and accident conditions. The NRC staff's human factors evaluation is conducted to confirm that operator performance will not be adversely affected as a result of system changes required for the proposed stretch power uprate. The NRC staff's review covers licensee's plans for addressing changes to operator actions, human-system interfaces, and procedures and training required for the proposed stretch power uprate. The NRC's acceptance criteria for human factors are based on 10 CFR 50.54(i) and (m), 10 CFR 50.120, and 10 CFR 55.59.

3.7.2 Technical Evaluation

The NRC staff has reviewed the following human factors area: (1) plant procedures, including emergency operating procedures (EOPs), (2) operator actions, (3) control room controls, displays, and alarms, (4) operator training program, and (5) startup testing. The licensee has addressed these areas in its January 29, 2004, application. Following is a summary of the licensee's responses and the NRC staff's conclusions.

3.7.2.1 Plant Procedures

The licensee stated that there were no significant changes to plant procedures required to implement the SPU. Those changes needed would be prepared in accordance with current procedure change control processes. The changes to the EOPs reflect the increased power level and associated setpoint changes. The EOP regarding the addition of supplemental feedwater to the SGs after a reactor trip will be changed to provide specificity for the flow and time requirements. Based on the above, the NRC staff finds that necessary procedures will be changed or updated prior to the implementation of the license and TSs changes associated with the proposed stretch power uprate. The NRC staff finds this acceptable.

3.7.2.2 Operator Actions

The licensee indicated that the proposed stretch power uprate is not expected to have any significant affect on the manner in which the operators control the plant during normal operations or transient conditions. The licensee also stated that changes to the operating procedures and setpoints would be part of operator training to be conducted prior to implementation of the SPU. As discussed in other sections of this SE, the licensee requested approval to credit the operator action to start the second MDAFWP or to align the TDAFWP within 10 minutes after reactor trip on a SG low-low water level signal to provide additional AFW flow to the SGs not fed by the AFW pumps assumed to start on the low-low SG water level signal for the SPU condition. The additional AFW supplied by the second pump will bring the plant to a stable condition, precluding a pressurizer water-solid condition. The licensee stated the EOP step for addition of supplemental feedwater to SGs after a trip already exists and operators have been able to complete this action in less than 10 minutes. However, the

procedure would be revised to provide specificity for the flow and time requirements for the SPU conditions. Thus, the NRC staff finds the operator actions acceptable since the implementation of the proposed SPU will not have an adverse effect either on operator actions or safe operation of the facility.

3.7.2.3 Control Room Controls, Displays, and Alarms

As described in the January 29, 2004, application, the licensee will make process paramenter setpoint and scaling changes, as required, to the Plant Integrated Computer System. There are no other effects on the systems from the SPU. Therefore, the NRC staff finds this acceptable.

3.7.2.4 Operator Training Program

The licensee stated that the changes in operating procedures and various system parameter setpoints will be incorporated into the operator training prior to implementation of the SPU. The operator response to any events will not be affected by the uprate conditions and response to alarms are anticipated to remain the same. Since the changes in procedures and setpoints will be included in the operator training program prior to the implementation of the SPU, the NRC staff finds this acceptable.

3.7.2.5 Startup Testing

As described in more detail in other sections of this SE, the licensee has stated that the startup following implementation of the SPU will be treated as a special evolution and the power escallation will be controlled by a Temporary Operating Procedure. The procedure incorporates hold points, performance monitoring and data collection. In addition, the licensee stated that it would conduct dry runs on the plant simulator to assure plant responses are as predicted. The results of the startup testing will be maintained as plant records. Therefore, the NRC staff finds the startup testing program acceptable.

3.7.3 Summary

The NRC staff has reviewed the licensee's planned actions related to the human factors area, and concludes that the licensee has adequately considered the impact of the proposed stretch power uprate on changes to operator actions, procedures, plant hardware, and associated training programs to ensure that operators' performance is not adversely affected by the proposed stretch power uprate. The NRC staff further concludes that the licensee will continue to meet the requirements of 10 CFR 50.54(i) and (m), 10 CFR 50.59, 10 CFR 50.120, and 10 CFR 55.59 following implementation of the proposed stretch power uprate. Therefore, the NRC staff finds the proposed stretch power uprate acceptable with respect to the human factors aspects of required system changes.

3.8 Plant Systems

3.8.1 Regulatory Evaluation

The NRC staff's review in the area of plant systems covers the impact of the proposed stretch power uprate on (1) containment performance analyses and containment systems, (2) safe shutdown fire analyses and required systems, (3) spent fuel pool cooling analyses and

systems, (4) flooding analyses, (5) main steam system, and (6) safety-related cooling water systems. The review is conducted to verify that the licensee's analyes bound the proposed plant operation at the stretch power level and that the results of licensee analyses related to the areas under review continue to meet the applicable acceptance criteria following implementation of the proposed stretch power uprate. Guidance for the NRC staff's review of plant systems is contain in Chapters 3, 6, 9, 10, and 11 of NUREG-0800.

3.8.1.1 LOCA Mass and Energy Release

Section 6.5.1.7 of the licensee's application discusses the acceptance criteria for the LOCA mass and energy release. The licensee cites 10 CFR Part 50, Appendix A, "General Design Criteria (GDC) for Nuclear Power Plants." Additionally, 10 CFR Part 50, Appendix K, Paragraph I.A, "Sources of heat during the LOCA," is cited as the criteria for the power sources considered in the analyses.

GDC 4 of 10 CFR Part 50, Appendix A requires that structures, such as the walls of subcompartments inside containment, shall be appropriately protected from the dynamic effects associated with pipe ruptures. GDC 4 also requires that structures, systems and components important to safety accommodate the environmental conditions of a LOCA. 10 CFR 50.49(e)(1) requires that the time dependent temperature and pressure at the locations of equipment important to safety must be established for the most severe DBA.

3.8.1.2 LOCA Containment Response

The licensee's application cites the following criteria for the containment response to the design basis LOCA.

UFSAR Chapter 5.1 discusses GDC 10 and requires the containment to be designed to withstand a large reactor coolant system pipe break without loss of integrity.

UFSAR Section 5.1 discusses GDC 49 and requires limiting leakage from the containment structure, including openings and penetrations, so as to not result in undue risk to the health and safety of the public.

UFSAR Chapter 9.1 discusses GDC 52 and requires that active heat removal systems needed to prevent exceeding containment design pressure shall perform their required function, assuming a single failure of an active component.

3.8.1.3 Main Steam Line Break

For the MSLB accident, the licensee's application lists the following GDCs of 10 CFR Part 50, Appendix A:

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

GDC 38 requires a system to remove heat from the reactor containment and that this system rapidly reduce the containment pressure and temperature following a LOCA.

3.8.2 Technical Evaluation

3.8.2.1 Containment Performance Analyses and Containment Systems

3.8.2.1.1 LOCA Containment Response

The LOCA containment response is divided into the short-term and the long-term response.

3.8.2.1.1.1 LOCA Short-Term Response

The short-term LOCA response analysis is also termed subcompartment analysis. A subcompartment is defined in SRP Section 6.2.1.2 as a fully or partially enclosed volume within the primary containment that houses high energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume.

For these evaluations, the licensee assumed an RCS pressure of 2310 psia and a vessel/core inlet temperature of 506.8 EF. This is a high value of pressure and a low value of temperature which is conservative for these calculations since this overestimates the mass released from the break.

The NRC has approved leak-before-break (LBB) technology for IP2. RCS piping determined not to catastrophically rupture according to the LBB technology does not have to be considered in subcompartment analyses. Consequently, as described in Section 6.5.2.2 of the January 29, 2004, application, the licensee determined that the double ended hot leg (DEHL) break with a 0.5 multiplier on the break area and a DECL break with a 0.32 multiplier on the cold leg break area were the limiting breaks. The licensee states that the 0.5 DEHL break represents a double ended pressurizer surge line break and the 0.32 DECL break represents an accumulator surge line break. As discussed in Section 6.5.2.2, the increases in pressure from these two breaks were small and do not exceed the 6.4 psi subcompartment pressurization design limit.

Since IP2 is approved for LBB, as discussed in Section 6.5.2.1 of the licensee's application, and the licensee's short-term calculations were conservatively done, these calculations are acceptable. Compliance with GDC 4 with respect to subcompartment analysis is maintained with the power uprate.

3.8.2.1.1.2 LOCA Long-Term Response

The mass and energy discharged from the break into containment are calculated using methods previously approved by the NRC[3]. Using these methods, the licensee calculated the IP2 containment's long-term response to the LOCA. These calculations were performed with

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

the Westinghouse containment code COCO[4], which has been used previously in NRC-approved LOCA analyses.

Table 6.5-23 of the licensee's application provides the conservative initial conditions used for the containment analyses. Table 6.5-31 contains the results of these analyses. It is reproduced below.

The containment design pressure is 47 psig and the containment design temperature is 271 EF. Since the calculated peak pressure and temperature are both less than the design values and have been calculated with acceptable methods using conservative assumptions, the IP2 long-term pressure and temperature containment LOCA responses are acceptable.

Table 6.5-31

LOCA Containment Response Results for IP2 Stretch Power Uprate				
CASE	PEAK PRESSURE (psig)	PEAK TEMPERATURE (EF)	PEAK PRESSURE AT 24 hrs (psig)	PEAK TEMPERATURE AT 24 hrs (psig)
Double Ended Pump Suction/ Minimum Safety Injection	45.71	266.81	17.05	204.989
Double Ended Pump Suction/ Maximum Safety Injection	39.67	257.596	21.38	216.192
Double Ended Hot Leg/ Minimum Safety Injection	40.62	259.98	NA	NA

3.8.2.1.2 MSLB Response

The double-ended rupture of a main steam line downstream of the flow restrictor is the design basis MSLB inside containment. The effective break area for IP2 with Westinghouse Model 44F SGs is 1.4 ft^2.

The licensee performed the MSLB calculations for IP2 using Westinghouse methods which have been previously approved by the NRC (References 4, 5, and 6 of Section 6.6.6 of the

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[4] Containment Pressure Analysis Code, WCAP 8327-P (Proprietary) and WCAP 8326 (Non-Proprietary), July 1974.

application), including the COCO code for the containment response to the MSLB. COCO has been used in many previous NRC-approved MSLB analyses.

As described in Section 6.6.1.2, the licensee assumed conservative input values for these analyses. Additionally, the MSLB accident calculations must examine a range of powers and single failure assumptions. Since a single failure is included in the mass and energy release calculations, the licensee does not model a single failure in the containment response calculations. This is standard procedure for this calculation, and is acceptable for IP2.

The main steam line double ended rupture peak containment pressure is 38.89 psig with the single failure of a feedwater control valve. This is less than the containment design pressure, and is therefore acceptable.

3.8.2.1.3 Generic Letter (GL) 96-06

During the review of GL 96-06 for IP2, the licensee found nine piping segments subject to overpressurization. Corrective actions restored these nine penetrations to within the allowable stress limits.

Section 10.11 of the application addresses overpressurization of containment piping penetrations for the stretch power uprate. The licensee states that a review of the evaluations of the piping segments subject to overpressurization leads to the conclusion that the only evaluation affected by the SPU is the evaluation of the return line from the loop 2 hot leg suction of the RHR pumps. The licensee concluded that:

> Due to the relatively small differences between the containment temperature profile used in the analysis and the containment temperature profile for a LBLOCA under SPU conditions, and a greater than 30% margin between the calculated maximum pressure and the maximum allowable pressure under UFSAR criteria, the stresses in this line under SPU conditions continue to remain within UFSAR allowables.

The NRC staff finds this acceptable since the licensee has reviewed the previous analyses for acceptability at stretch power uprate conditions and determined that adequate margin remains with the stretch power uprate.

3.8.2.1.4 Environmental Qualification (EQ): Environmental Parameters Inside Containment

Section 10.8.2 of the January 29, 2004, application discusses the environmental parameters inside containment. The licensee states that the SPU has no effect on the qualification of equipment inside containment with respect to the temperature. The licensee states that during normal operation, the temperature is unchanged from the qualification basis of 120 EF.

In addition, the pre-power uprate accident temperature profile used for the EQ Program bounds the containment reanalysis temperature profile from the LOCA. The IP2 licensing basis does not use the MSLB inside containment as a basis for EQ.

Since the containment conditions assumed for EQ remain bounding for the power uprate EQ, and these have been previously reviewed and approved by the NRC, the licensee's

determination of environmental conditions for the EQ Program is acceptable for SPU conditions.

3.8.2.1.5 Proposed Changes to the IP2 TSs

3.8.2.1.5.1 Surveillance Requirement (SR) 3.5.4.1

The licensee has proposed increasing the upper limit of the RWST water temperature from 100 EF to 110 EF. The licensee states in Attachment I to the January 29, 2004, letter that this change will provide additional operating margin for the summer months.

Since the containment spray initially takes suction from the RWST during the LOCA and the main steam line break accident, this is an important input to the containment safety analyses. Since these analyses demonstrate acceptable results while using this spray temperature, this TS change is acceptable.

3.8.2.1.6 Conclusions for Containment Performance Analyses and Containment Systems

The NRC staff has reviewed the containment DBA analyses and finds the licensee's analysis methods and results satisfactory since acceptable methods and conservative assumptions were employed and the applicable regulations remain satisfied.

3.8.2.2 Safe Shutdown Fire Analyses and Required Systems

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that SSCs required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire. The NRC's acceptance criteria for the FPP are based on (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant; and (2) draft GDC-3, insofar as it requires that the reactor facility be designed (a) to minimize the probability of events, such as fire and explosions, and (b) to minimize the potential effects of such events to safety. Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of Review Standard 001 (RS-001), Revision 0, *Review Standard for Extended Power Uprates*, December 2003.

Attachment 2 to Matrix 5, which is also used in the SPU review, states that "... power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire ... [W]here licensees rely on less than full capability systems for fire events ..., the licensee should provide specific analyses for fire events that demonstrate that (1) fuel

integrity is maintained by demonstrating that the fuel design limits are not exceeded and (2) there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe shutdown procedures."

Sections 4.1.3 ("Residual Heat Removal System"), 6.9 ("Natural Circulation Cooldown Capability"), and 10.1 ("Fire Protection [10CFR50 Appendix R] Program") of January 29, 2004, application, as supplemented by the response to RAIs, satisfactorily addressed these fire protection requirements of RS-001. In addition, the licensee provides references from their Fire Protection Program Plan that demonstrate auxiliary feedwater would be injected prior to SG dryout by an acceptable time margin. This information satisfactorily demonstrates the licensee's compliance.

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and draft GDC-3 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to fire protection.

3.8.2.3 Main Steam System

The function of the Main Steam System (MSS) is to transport saturated steam from the four SGs to the main turbines for power generation over the entire operating range, from system warmup to full power operation. The steam dump and bypass systems provide alternate flow paths for the steam that is generated in the SGs when the main turbine is not available, or when an operational transient requires a reduction in the main turbine power level. In addition to supplying saturated steam to the main turbines, the MSS also provides steam for the main boiler feed pump turbines, moisture separator reheaters, turbine gland sealing steam system, priming and steam jet air ejectors, AFW pump turbine, and auxiliary steam system.

The MSS is described in the IP2 UFSAR (Reference 11), Section 10.2.1, and its configuration is shown in Figure 10.2-1, sheets 1, 2, and 3. The major components of the MSS are the MSSVs, power-operated atmospheric relief valves (ARVs), and the main steam isolation valves (MSIVs) and associated non-return valves. The design pressure of the MSS is 1085 psig at 600 EF, and the system is classified as Class I for seismic design from the SGs up to and including the MSIVs. The current licensing basis requires the MSIVs to close within 5 seconds to mitigate a MSLB. Additionally, as described in Section 10.2.1 of the UFSAR, the MSIVs were redesigned to withstand the dynamic forces associated with this rapid closure and are in compliance with 10 CFR Part 50, Appendix A, GDC 4 requirements.

The licensee has evaluated the MSS piping, valves, and components to verify their capability to perform at the proposed SPU conditions. The criteria used in the analysis included: main steam (MS) pressure and flow rate to meet the high pressure (HP) turbine inlet conditions; sufficient steam supply to the auxiliaries (i.e., steam driven feedwater pumps, et al); consideration of operating pressures, temperatures, velocities, and line sizing associated with

the SPU and abnormal and accident conditions; closure time for the MSIVs; and set points for ARVs and MSSVs. The licensee determined that the current MSS and associated components at IP2 are capable of performing their design functions under SPU conditions. Areas of the MSS that are impacted by the proposed power uprate such that reactor safety considerations could potentially be affected are discussed below.

3.8.2.3.1 MS System Piping

Implementation of SPU will increase the SG steam outlet mass flow rate by 6-percent above the current mass flow rate, which will impact MS header piping pressure drops and flow velocities. The pressure drop from the SG to the HP turbine inlet throttle valve was calculated at the SPU condition and found that there would be adequate flow and pressure to satisfy the throttle valve inlet requirements for the proposed power uprate. The MS piping design pressure and temperature bound the SPU operating conditions. According to Item 24 in Attachment II to the licensee's April 12, 2004, letter, the increased flow velocities in the MS header from the SGs during SPU operation were found to be 161 ft/sec, which is within the industry accepted limits (i.e., 100 - 167 ft/sec). Based on these considerations, the NRC staff considers the MSS to be suitable for SPU operation.

3.8.2.3.2 AFW Pump Turbine Steam Supply

In the event of abnormal and accident conditions, the MSS must supply steam to the AFW pump turbine. The AFW pump turbine is designed to operate at very low main steam pressures during plant startup and shutdown operations, up to a maximum of 600 psig supply pressure during normal plant operating conditions. A pressure control valve on the steam supply line to the AFW pump turbine reduces the pressure to 600 psig or less when the MS supply pressure exceeds this limit. Because SPU will not affect the maximum (no-load) SG pressure, the steam supply to the AFW pump turbine is unaffected.

3.8.2.3.3 MSIVs and Non-Return Valves

The MSIVs and non-return check valves for IP2 are located outside the containment and downstream of the MSSVs. The safety function of these valves is to prevent uncontrolled blowdown of more than one SG, and they are required to have the capability of closing within 5 seconds or less in the event of a MS line rupture. Rapid closure of the MSIVs and non-return valves following postulated steam line breaks causes a significant differential pressure across the valve seats and thrust load on the MSS piping and piping supports in the areas of these valves. Based on Westinghouse analysis described in Section 4.2.1.3 of its application, the licensee determined that the SPU will not affect the design loads and associated stresses resulting from rapid closure of the MSIVs and non-return valves. Further, the licensee determined that the existing MSIVs and non-return valves are acceptable for SPU operation without modification. This is consistent with the NRC staff's expectations for relatively small constant pressure power uprates.

3.8.2.3.4 MS System Summary

Based on a review of the information that was provided (as discussed above), the NRC staff finds that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSS. The NRC staff concludes that the MSS will maintain its ability to function as assumed in the UFSAR following SPU implementation and that reactor safety will not be degraded. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the MSS.

3.8.2.4 Condensate and Main Feedwater Systems

The condensate and main feedwater (FW) systems consist of three one-third capacity condensate pumps, two half-size heater drain pumps, and two half-size turbine-driven main FW pumps. The condensate system (CS) transfers condensate from the main turbines and low-pressure heater drains that collects in the hotwell through five stages of FW heaters to the suction side of the main FW pumps. The two heater drain pumps take suction from the heater drain tank, where the drains from the high-pressure heaters are collected, and discharge into the condensate header upstream of FW pumps. The FW pumps increase the pressure of the condensate and delivers the FW to the SGs via the final stage of the high pressure heaters and FW regulating valves. The FW system controls the FW flow via the FW regulating valves and the FW pump turbine speed control system. The CS and FW systems are described in IP2 UFSAR Section 10.2.6, and corresponding flow diagrams are provided in Figures 10.2-5 and 10.2-7, respectively.

The licensee evaluated the CS and FW system and associated piping, pumps, valves, and pressure-retaining components to confirm their ability to operate successfully at the proposed SPU conditions. A hydraulic flow model was used to analyze and evaluate the performance of the CS and FW system under the proposed power uprate conditions, considering both normal plant operation and postulated transient conditions. The evaluation was focused on determining the impact of the proposed SPU on, but not limited to: (1) the operation of the CS, FW, and Heater Drain pumps, including flow capacity, discharge pressure, and net positive suction head; (2) system pressures and temperatures; (3) operation of the FW heaters; and (4) isolation capability afforded by the FW Regulating and Isolation valves. Based on a review of the information that was submitted, the NRC staff found that the area of primary interest with respect to reactor safety considerations involves the FW Regulating and Isolation Valves.

The FW Regulating and Isolation Valves are located outside the containment and are designed to isolate FW flow to the SGs following unisolable steam (or FW) line breaks or malfunctions in the SG level control system. Isolation of FW flow is required to prevent containment over-pressurization and excessive cooldown of the RCS. The results of the licensee's analysis indicated that while FW flow rate requirements will increase slightly for the proposed power uprate condition, FW system design requirements and limiting assumptions for the current licensed power level will not be exceeded as a result of the proposed power uprate. Therefore, based on the information that was provided, the NRC staff finds that the proposed SPU is acceptable relative to the FW Regulating and Isolation Valves.

3.8.2.5 Service Water System & Ultimate Heat Sink

The Hudson River is the ultimate heat sink (UHS) for IP2. The IP2 Service Water System (SWS) is a safety-related system designed to supply cooling water from the Hudson River to various heat loads, that is, essential and non-essential components of both primary and secondary plant systems. The essential loads are those which must have an assured supply of cooling water immediately after a loss of offsite power (LOOP) and/or a LOCA. The IP2 SWS consists of two independent discharge headers and each header is connected to an independent supply line; either of which can be used to supply the essential loads. Essential and non-essential SWS loads are listed in the IP2 UFSAR Table 9.6-1. The SWS removes waste heat from the equipment for all plant operating modes and rejects waste heat to the Hudson River through a discharge canal. Also, according to Section 9.6.1 of the application report, during periods of high river water temperatures, a cross-connection to Indian Point Unit 1 can be aligned to supply the non-essential loads.

The proposed SPU will slightly increase the amount of heat being rejected to the SWS. The licensee has modified the latest system hydraulic analysis to incorporate this increased heat load and has evaluated the capability of the SWS to provide adequate cooling and to withstand the effects of slightly higher outlet temperatures and pressures. The hydraulic analysis included worst-case assumptions, such as low river water level, higher inlet water temperatures (e.g., 95 EF), 7% degraded pump curves, and atmospheric vents where applicable. As discussed in Section 9.6 of the application and in Item 9 in the April 12 letter, the licensee concluded that SPU operation will not affect the flow requirements of any of the essential heat loads; outlet SWS temperatures were confirmed to be within the system and equipment design specifications; and SWS pump operating parameters, including net positive suction head, were found to be within the allowable design specifications. Consequently, the licensee concluded that no changes or equipment modifications would be required for the SWS or the UHS in support of the proposed power uprate.

As Attachment II, Item 10, of the April 12 letter, the licensee has assessed the impact of the proposed power uprate on the resolution of the GL 96-06 waterhammer issue. The licensee concluded that the column closure waterhammer and the trapping and condensing of steam (steam bubble or void collapse) waterhammer will not be significantly affected by the small (less than 3-percent) increase in containment accident peak temperature under SPU conditions. That is, the velocity (critical parameter) of column closure and the volume (critical parameter) of steam bubble formation are not significantly changed by the small increase in containment ambient temperature. The licensee also evaluated the studies that were performed in response to GL 96-06 and determined that the proposed power uprate will not affect the results of existing analyses that were performed to assess the impact of two-phase flow conditions during a DBA.

The NRC staff has reviewed the information that was provided and the licensee's assessment referred to above regarding the effects of the proposed SPU on the capability of the UHS and SWS to perform their respective functions. Based on a review of the information that was provided, the NRC staff finds that these areas have been adequately addressed and will remain capable of performing their required safety functions following power uprate in accordance with the existing licensing basis for IP2.

3.8.2.6 Auxiliary Feedwater System

The AFW system supplies FW to the secondary side of the SGs when the normal FW supply is not available. The system removes decay heat from the reactor core by heat exchange in the SGs when the main FW pump(s) are not functional, thereby maintaining the required heat sink for the RCS. The system provides FW to the SGs during normal unit startup, hot standby, and cooldown operations. The AFW system also functions as an engineered safeguard system and is directly relied upon to dissipate reactor decay heat and to prevent core damage and system over-pressurization in the event of transients and accidents, such as during a loss of normal FW or during a secondary system pipe break.

The AFW system consists of two MDAFWPs and one TDAFWP, associated valves and piping, and control systems to enable the AFW system to satisfy single active failure and diversity of power source and type considerations. The system flow diagram is given in IP2 UFSAR Figure 10.2-7. IP2 has 4 SGs; and the AFW system consists of two distinct safety-grade subsystems, (i.e., two pumping systems), one using the TDAFWP and the other using the two MDAFWPs in order to ensure reliability of the AFW supply. The TDAFW subsystem has sufficient SG makeup capacity for dissipating 200% of the maximum reactor decay heat and is configured to feed all four SGs. With respect to the other AFW subsystem, each of the two motor-driven pumps is designed for 100% decay heat removal capability and each pump feeds two of the four SGs.

As described in Sections 4.2.4 and 9.12 of the application, the licensee has performed analyses and evaluated the AFW system for the proposed SPU conditions. The normal (short-term) source of water supply to the AFW pumps is from the safety-related condensate storage tank (CST) by gravity feed. The limiting transients with respect to CST inventory are the LOOP and loss-of-AC power. The IP2 licensing basis requires that, in the event of a LOOP, sufficient usable inventory must be available to bring the unit from full power to hot standby conditions and maintain the plant at hot standby for 24 hours. The licensee determined that the minimum usable inventory that is necessary to satisfy the plant licensing basis for the range of NSSS design parameters that are specified for SPU will increase from the current 284,000 gallons to 291,381 gallons. The existing IP2 TS requires a minimum inventory of 360,000 gallons in the CST, which is sufficient for the proposed SPU conditions. The licensee also determined that the design pressures and temperatures of the AFW system piping and associated valves and components will continue to be bounding for SPU operation, and the AFW pump design criteria will continue to be satisfied. Consequently, the licensee has concluded that the existing AFW system, including its associated pumps and components, is acceptable for operation at the proposed power uprate conditions.

The NRC staff has reviewed the licensee's assessments regarding the AFW system, and find that the licensee has adequately adresssed the impact of the proposed power uprate on the ability of the AFW system to supply water to the SGs. The NRC staff has concluded that the AFW system will continue to satisfy its licensing basis following implementation of the proposed power uprate and therefore, the proposed uprate is acceptable with respect to AFW system considerations.

3.8.2.7 Spent Fuel Pool Cooling System (SFPCS)

As described in IP2 UFSAR Sections 9.3.1.1.3 and 9.3.2.3, the spent fuel pool (SFP) cooling loop at IP2 consists of two pumps, a heat exchanger, a filter, a demineralizer, piping, and associated valves and instrumentation. One of the pumps draws water from the SFP (the other pump is on standby), and circulates the water through the heat exchanger and returns it to the pool. Component cooling water cools the heat exchanger. The SPF cooling loop piping is so arranged that failure of any pipe does not drain the SFP below the stored fuel elements.

The function of the SFPCS is to remove decay heat from the spent fuel assemblies stored in the SFP. The current design basis of the SFPCS is to maintain the pool water temperature below 140 EF during normal and refueling operations following a partial core offload of 72 freshly discharged fuel assemblies with the remaining spaces of the fuel rack filled with previously discharged fuel assemblies (assumes the uprated power history for all spent fuel assemblies). Likewise, when a full core is freshly discharged, the pool temperature is maintained below 180 EF (UFSAR Section 9.3.1.2.3).

Since the decay heat rate of the spent fuel is a function of the core power level, the proposed SPU will result in higher heat loads for the SFP. According to Section 4.1.7 of its application, the licensee has chosen to perform cycle-specific heat load evaluations using the anticipated actual conditions at the time of offload prior to each refueling outage. This evaluation will be based on expected service water (SW) temperature, component cooling water flow, SFPCS heat exchanger performance capability (i.e., heat transfer area and tube plugging), and reload-specific SFP heat removal requirements which will determine the decay time needed such that bulk SFP temperature will remain below 140 EF for partial core offloads (i.e., 72 assemblies) and below 180 EF for full core offloads.

The licensee described the analysis methods that would be adopted for reload-specific calculations, which includes a calculation of decay heat load in SFP, and a calculation of heat removal capacity. The calculation of the decay heat load will be based on decay time, power history, and inventory of the SFP at the time of the reload (i.e., actual fuel assemblies in the SFP in conjunction with the decay heat characteristics of the fuel being offloaded from the core). Whereas, the calculation of heat removal capability will be based on the current values of parameters that affect cooling capacity. The specific inputs to the calculation will be representative of the conditions predicted to exist at the time the core offload is scheduled to take place. Also, at the time of reload, the licensee will confirm that the cycle-specific analysis is in fact conservative.

If the cycle-specific calculation shows that the SFP temperature will exceed 140 EF for the normal fuel offload and 180 EF for full core offload, then movement of fuel from the reactor into the SFP will be delayed until the fuel has decayed to a point where the SFP temperature criteria will not be exceeded. The licensee indicated that the required hold time will be documented in the cycle-specific calculation and that procedural requirements will be established for controlling the in-core hold time of the fuel after shutdown in order to ensure the SFP design-basis temperature limitations are not exceeded. Consequently, the licensee has concluded that physical or analytical modifications to the SFP or its cooling system are not necessary in order to accommodate the proposed power uprate. The licensee's plan to perform cycle-specific analysis, as discussed above, is consistent with the NRC staff's review criteria and will assure that design-basis SFP temperature limitations are not exceeded.

Additionally, the licensee assessed the SFP makeup requirements for the normal and full core offload conditions with the maximum number of fuel assemblies stored in the SFP (assuming the uprated power history for all fuel assemblies). For normal SFP conditions, if the SFP were to lose all cooling with an initial pool temperature of 140 EF, the time-to-boil would be 8.3 hrs and the required make-up capacity would be 35 gpm. For the full core offload, with an initial temperature of 180 EF, the time-to-boil is at least 1.67 hours and the maximum required makeup capacity would be 75 gpm (Section 4.1.7 of the application). Prior to power uprate, the corresponding figures for full core offload are 1.8 hrs and 62 gpm, respectively. However, in response to questions that were raised by the NRC staff, the licensee reevaluated the time-to-boil for the full core offload case and stated that the existing 1.8 hours for time-to-boil would be maintained consistent with the existing plant licensing basis. Also consistent with the existing licensing basis, Entergy credits the primary water storage tank, the RWST, and the fire protection system for satisfying makeup water requirements.

The NRC staff has reviewed the information that was provided and the licensee's assessment of the effects of the proposed power uprate on the SFPCS. Based on the licensee's assessment, it plans to: (1) perform cycle-specific analyses and administratively control the in-core hold time of the fuel after reactor shutdown to ensure that the SFP temperature will not exceed design basis temperatures; and (2) maintain alternate SFP makeup capability in accordance with the plant licensing basis in order to mitigate unexpected boil-off of the SFP as discussed above, the NRC staff finds that the licensee has adequately considered and addressed any adverse impacts that the proposed SPU may have on the SFPCS and makeup capability. Therefore, the SFPCS is considered to be capable of performing its licensing-basis functions following the proposed power uprate.

3.8.2.8 Steam Dump System

The Steam Dump System provides a steam flow path directly to the condenser and/or atmosphere which bypasses the turbine, thereby providing the capability to accommodate turbine load transients without forcing a reactor trip. The Steam Dump System creates an artificial steam load by dumping steam from ahead of the turbine throttle valves to the condenser. As described in Section 4.2.2 of the application, the Westinghouse sizing criterion recommends that the Steam Dump System (valves and piping) be capable of discharging 40% of the rated steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 50% of plant-rated electrical load without a reactor trip. The current licensing basis for IP2 uses this 40% steam dump criterion (UFSAR, Section 10.2.1.1).

According to Section 4.2.2 of the application, an evaluation of the Steam Dump System indicated that the existing system capacity would be reduced to 34.4% of the SPU full-load steam flow at the current minimum allowable steam pressure of 650 psia and corresponding Tavg values of lower than 558 EF. Higher values of Tavg result in higher steam pressures, thereby increasing the steam dump capacity. Therefore, as the full-power Tavg is increased, larger load rejections can be successfully handled without resulting in a reactor trip. According to Section 4.3.1.3.3 of the application, the licensee's analyses demonstrated that, for full-power Tavg values of 558 EF and above, the 50% design-basis load rejection can be accommodated for the SPU conditions. Also, in the above cited reference and in Item 25 of the April 12 letter, the licensee indicated that plant operation following the SPU uprate would be at a normal full power T_{avg} of 562 EF. Thus, the Steam Dump System will maintain its 50% load rejection

capability for SPU during normal full power operating conditions; the NRC staff considers this to be acceptable.

3.8.2.9 Component Cooling Water System

The Component Cooling Water System (CCWS) is required to provide cooling water to various plant components during plant normal, shutdown, and post-accident operations. The CCWS also acts as an intermediate system between the components being cooled (including those in the radioactive fluid systems) and the SWS.

As discussed in Section 4.1.6 of the application, the limiting heat loads for CCWS occur during normal plant operations, the 10 CFR Part 50, Appendix R (Fire Protection) cooldown, and during post-LOCA plant cooldown. The SFP is the only load with a potential to affect the CCWS following power uprate. The licensee has evaluated the CCWS and its components and has determined that the existing CCWS capability is adequate for the proposed SPU conditions with no equipment changes. Further, the licensee's analysis indicated that CCWS supply temperatures will not exceed the current operational limits as depicted on Page 4.1-13 of the above reference. Based on these considerations, the NRC staff considers the proposed power uprate to be acceptable with respect to the CCWS.

3.8.2.10 Main Turbine

As discussed in Section 8 of the application, the licensee evaluated the main turbine unit and plans to replace the high pressure (HP) turbine in order to optimize the efficiency and increase its capacity for the proposed power uprate. The HP turbine first-stage instrumentation will be adjusted to correspond to the new uprated pressure conditions. Peripherals of the HP turbine, such as the existing turbine bearings, gland seals and associated steam system, lube oil system, hydraulic control system, main steam inlet piping, stop valves, throttle valves, control valves, and cross-over/under piping will remain unchanged. The licensee determined that no modifications were required associated with the low-pressure turbines.

The NRC staff's review focused primarily on two areas: a) design features that are credited for preventing turbine overspeed, and b) turbine missile protection features that are credited for protecting SSCs. Based on a review of the information that was provided and confirmatory discussions with the licensee, it is the NRC staff's understanding that design features that have been established for preventing turbine overspeed are not affected by the proposed uprate, and surveillance testing will confirm that these existing features continue to be acceptable; and SSCs important to safety are not located within the strike zone of postulated turbine missiles. Consequently, these areas are not impacted by the proposed power uprate, and are therefore, acceptable for the proposed SPU conditions.

3.8.2.11 Internally Generated Missiles Outside Containment

The potential sources of internally generated missiles outside containment include such things as pipe fittings, bolts, valve bonnets, and other components. The potential for turbine missiles is addressed earlier in this evaluation. Regarding the other sources of missile generation, the operating pressures of high and moderate energy piping systems are minimally affected by the proposed power uprate and the licensee has determined that rotating equipment will not exceed existing design limitations. Therefore, based on the information that was provided, the NRC

staff finds that existing analyses pertaining to internally generated missiles outside containment are not affected by power uprate and remain valid.

3.8.2.12 Flooding

As depicted in Table 3, Line Item 10.4, of the April 12 letter, flooding at IP2 is not affected as a result of the proposed SPU conditions. In Item 1of this letter, the licensee discussed the effects of power uprate on the existing flooding analysis. Based on the information that was provided, the NRC staff found that the only area potentially affected from a reactor safety perspective is the AFW pump rooms. The increase in FW system flow rates following SPU implementation could result in an increase in flooding in the area outside the AFW pump room due to a postulated high energy line break in the main FW system. However, current provisions (i.e., door design, procedural controls) are in place to ensure that flooding from failure of the main FW line in this area will not impact the AFW pump room. Therefore, based on the information that was provided, the NRC staff finds that the existing flooding analysis is not affected by power uprate and remains valid.

3.8.2.13 High Energy Line Break

According to Section 9.9.5 of the application, the licensee indicated that changes to operating pressures, temperatures, and flow rates for high and moderate energy piping systems remain bounded by existing analysis and no new pipe break locations result as a consequence of SPU implementation. Therefore, based on the information that was provided, the NRC staff finds that the existing high energy line break analysis (HELB) is not affected by power uprate and remains valid.

4.0 LICENSE AND TS CHANGES

The amendment of rated thermal power (RTP) to 3216 MWt is supported by the appropriate safety analyses, and is acceptable based on the NRC staff evaluation described in the above sections. The application would also amend several LCOs of the IP2 TSs. The TS amendment includes changes to the allowable values (AVs) of several RTS trip functions and ESFAS functions, the relocation of the cycle-specific RCS minimum measured flow (MMF) limit to the COLR, and changes to the limiting values of pressurizer water level, boron concentrations of the accumulators and RWST, and the reduced thermal power limits with inoperable MSSVs. The NRC staff evaluation of each of these proposed changes is described below.

4.1 Change to Facility Operating License No. DPR-26

The licensee proposes to change the RTP from 3114.4 to 3216 MWt. On the basis of the evaluation provided in Section 3.0 above, the NRC staff finds the proposed change acceptable.

4.2 Change to TS 1.1

The licensee proposes to revise the RTP in IP2 TS 1.1, “Definitions,” from 3114.4 to 3216 MWt. On the basis of the evaluation provided in Section 3.0 above. Also, the licensee proposes to revise the Dose Equivalent 1-131, TS Section 1.1. This proposed change is not a result of the stretch uprate program. The updated definition is being proposed to be more consistent with

the dose analysis methodology previously adopted by the AST license amendment (Amendment No. 211, issued July 27, 2000). There are no Bases for this TS section. The NRC staff finds the proposed changes acceptable.

4.3 TS 3.3.1 Reactor Trip System Instrumentation

The licensee proposed to change the AVs and footnotes of several reactor trip functions in TS Table 3.3.1-1. The AV of a trip function is an expected value that the trip setpoint might have when tested periodically due to instrument drift or other uncertainties associated with the test, and is used to determine the trip function's operability status. Table 2, "Cross-Map of TS Changes to WCAP-16157-P Analyses," of Attachment I to the April 12, 2004, letter provided descriptions for the AV changes. In response to an NRC staff RAI, the licensee provided calculations of the channel statistical allowance (CSA) and AV for each of these trip functions in Attachment II to a June 16, 2004, letter. These calculations were performed with the methodology described in IP2 Specification No. FIX-95-A-001, Revision 1, "Guidelines for Preparation of Instrument Loop Accuracy and Setpoint Determination Calculations," dated November 2001. For each trip function, the licensee used two methods described in Section 5.12 of FIX-95-A-001 to calculate the AVs, and the more conservative value of the two calculated results is used as the AV, where the conservative value is the minimum (or maximum) value of the two for increasing (or decreasing) parameters. The NRC staff evaluation of these AV changes are described below:

(1) Function 2.a, Power Range Neutron Flux - High

This trip function provides protection against uncontrolled rod withdrawal at power event. For the SPU, the licensee proposed to change the AV of this trip function from 112.0% RTP to 110.6% RTP with the nominal trip setpoint (NTS) remaining unchanged at 109% RTP. The safety analysis limit (SAL) of this trip function, i.e., the trip setpoint assumed in the SPU safety analysis, is reduced from 118% RTP to 116% RTP to ensure that the licensing basis acceptance criteria of DNBR limit is met. Table 2 in Attachment II to NL-04-073 provided the calculation of CSA and AV of this trip function. With the SAL and NTS of 116.0% and 109% RTP, respectively, the AV was calculated to be 110.6% RTP, which is consistent with the proposed value.

(2) Function 5, Overtemperature ΔT (OTΔT)

The OTΔT trip function provides DNB protection against non-LOCA transients. The trip setpoint, described in Note 1 under Table 3.3.1-1, is calculated by ΔT_0 (i.e., loop specific indicated ΔT at full power) multiplied by a cycle-specific constant K_1, and other correction factors to account for variations in RCS temperature, RCS pressure, and axial offset. Since the OTΔT trip setpoint varies with the plant operating conditions, the AV of this function is specified as the percentage of the ΔT span that the channel maximum trip setpoint may exceed its computed trip setpoint. For the SPU, the licensee proposed to change from 3.3% to 4.9% ΔT span that the channel maximum trip setpoint may exceed its computed trip setpoint.

The OTΔT trip setpoint is directly proportional to the input constant K_1. The SAL for K_1 in the SPU safety analysis is changed from 1.40 to 1.42, and the NTS for K_1 remains unchanged at 1.22. Table 3 in Attachment II to NL-04-073 provides a detailed calculation of the CSA and AV for the OTΔT function. The AV is calculated to be 129.4% RTP, which is 7.4% RTP over the

NTS of K_1 of 122% RTP. Adjusting for the power span of 150% RTP to the ΔT span, the AV is 4.9% ΔT span over the computed setpoint, which is consistent with the proposed value.

The licensee also proposes to clarify the definition of ΔT_0 and T' in the OTΔT function by referring them to the "loop specific indicated" ΔT and T_{avg} at RTP, respectively, which are editorial changes and are acceptable.

(3) Function 6, Overpower ΔT (OPΔT)

The OPΔT trip function, described in Note 2 under Table 3.3.1-1, provides fuel centerline temperature protection for non-LOCA transients. The trip setpoint is calculated by ΔT_0 multiplied by a cycle specific constant K_4, and other correction factors to account for variations in RCS temperature and axial offset. For the SPU, the licensee proposed to change the AV from 2.3% to 2.4% ΔT span that the channel maximum trip setpoint may exceed its computed trip setpoint.

The OPΔT function trip setpoint is directly proportional to K_4. The SAL for K_4 in the SPU safety analysis is changed from 1.154 to 1.164, and the NTS for K_4 remains unchanged at 1.074. Table 4 in Attachment II to NL-04-073 provides a detailed calculation of the CSA and AV for the OPΔT function. The AV is calculated to be 111.0% RTP, which is 3.6% RTP over the NTS of K_4 of 107.4% RTP. Adjusting for the power span of 150% RTP, the AV is 2.4% ΔT span over the computed setpoint. Therefore, the NRC staff concludes the proposed change is acceptable.

The licensee also proposes to clarify the definition of ΔT_0 and T' in the OPΔT function by referring them to the "loop specific indicated" ΔT and T_{avg} at RTP, respectively, which are editorial changes and are acceptable.

(4) Function 9, Reactor Coolant Flow - Low

This trip function provides protection against partial and complete loss of RCS flow and locked rotor events. The LAR would change the trip function AV from 88.8% to 88.7%. Table 5 in Attachment II to NL-04-073 provides the calculation of the CSA and AV of this function. The SAL and NTS remain at 85% and 92% flow, respectively. The uncertainty for the RCS flow calorimetric of the process measurement accuracy is reduced from 2.9% to 2.8%, the AV is calculated to be 88.5%. The use of 88.7% AV in the TS is conservative, and acceptable.

(5) Function 13, Steam Generator Water Level - Low Low
Function 14, SG Water Level - Low:

These trip functions provide protection against loss of heat sink from a loss of normal feedwater transient. The LAR would change the AV of these trip functions from 3.7% narrow range (NR) to 3.4% NR. Table 6 in Attachment II to the June 16 letter provides calculations of the CSA and AV of this function. The SAL and NTS remain unchanged at 0% and 7% of span, respectively. However, since the uncertainty for the process measurement accuracy (PMA) is reduced, the AV is calculated to be 3.4%, consistent with the proposed value. Therefore, the AV revision is acceptable.

4.4 TS 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

The application would change the AVs of the following functions in Table 3.3.2-1.

(1) Functions 1.f and 4.d, "High Steam Flow in Two Steam Lines, Coincident with T_{avg} - Low"

This ESFAS function initiates safety injection and steam line isolation for protection against the steamline break events. The AV for the T_{avg} - Low setpoint is changed from 540.75 EF to 540.5 EF. The AVs for the high steam flow are changed from 53.7% to 45.9% of full steam flow at or below 20% load, and from 110.8% to 122% of full steam flow above 100% load.

This ESFAS actuation logic setpoints are changed to enable a more timely actuation of the steam line isolation and safety injection for the SLB protection. The SAL for T_{avg} - Low is assumed to be 537 EF, and the NTS is changed from 540 EF to 542 EF. The high steam flow SAL is changed from 74% to 64% of full flow at or below 20% load, but the NTS remains unchanged at 40% of full flow at or below 20% load, and 110% of full flow at 100% load.

In Table 9 of Attachment II to the June 16 letter, the licensee provides a detailed calculation of the CSA and AV for the T_{avg} - Low setpoint. With the T_{avg} - Low SAL of 537.0 EF, the calculated AV is 539.1 EF. The proposed value of 540.5 EF is conservative and acceptable.

In Tables 10 and 11 of Attachment II to June 16 letter, the licensee provide the CSA and AVs for the high steam flow rate setpoints at 100% power and 20% power, respectively. With the high steam flow rate SALs of 144% and 64% of full flow at 100% and 20%, respectively, the calculated AVs are 133.8% and 45.9% full steam flow for 100% and 20% loads, respectively. Since the flow span is 122%, the AV for 100% load is set at 122% full flow. Therefore, the proposed change for the high steam flow setpoint AVs is acceptable.

(2) Functions 1.g and 4.e, "High Steam flow in Two Steam Lines, Coincident with Steam Line pressure - Low"

These ESFAS functions initiate safety injection and steam line isolation for mitigation protection against the steamline break events. For the SPU, the AV for the low steam line pressure setpoint is changed from 525.0 psig to 540.3 psig. The AV for the high steam flow is changed as discussed in Item (1) above.

Table 8 of Attachment II to June 16 letter, the licensee provides a detailed calculation of the CSA and AV for the Steamline Pressure - Low setpoint. With the steamline pressure- Low SAL of 515.3 psig, the calculated AV is 540.3 psig. The proposed value of 540.3 psig is acceptable.

(3) Function 5.b, Feedwater Isolation - SG Water Level -High High

This ESFAS function provides protection for overfilling the SGs. For the SPU, the SAL for this function is being changed from 80% to 90% NR level due to potential increase in uncertainties associated with SG level process uncertainties. The licensee proposed to change the AV from 77.7% NR to 88.3% NR.

In Table 7 of Attachment II to the June 16 letter, the licensee provides the CSA and AV high SG water level setpoint. With SAL of 90% NR, the calculated AV is 88.3% NR. Therefore, the proposed change is acceptable.

(4) Function 6 b, Auxiliary Feedwater - SG Water Level - Low Low

This ESFAS function provides protection against loss of normal feedwater. The licensee proposed to change the setpoint AV from 3.7% NR to 3.4% NR. Table 6 of Attachment II to the June 16 letter provides detailed calculation of the AV. The NRC staff has evaluated this calculation and found it acceptable as described above under RPS Functions 13 and 14 of Table 3.3.1.1.

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

The licensee proposed to revise LCO 3.4.1, Item c, from "RCS total flow rate $ 331,840 gpm" to "RCS total flow rate $ 322,800 gpm and greater than or equal to the limit specified in the COLR." SR 3.4.1.3, SR 3.4.1.4, and TS Bases B3.4.1 are also revised accordingly.

The licensee stated that this proposed change is not a result of the SPU program, but is part of recent conversion to Improved TSs. In NUREG-1431, Revision 3, TS 3.4.1, the DNB parameter limits of RCS pressure, temperature, and minimum measured flow (MMF) are relocated to the cycle-specific core operating limits report (COLR), and the LCO retains the minimum RCS total flow limit that was reviewed by the NRC in the SE for the Improved TSs. The NRC staff notes that the MMF specified in the COLR, which is larger than the RCS flow limit retained in LCO 3.4.1.c and SR 3.4.1.3, is the value to determine the LCO compliance. This is consistent with WCAP-14483-A, "Generic Methodology for Expanded Core Operating Limits Report." The NRC staff safety evaluation of WCAP-14483 indicated that the reason for retaining the minimum RCS total flow rate limit in the TS is to ensure that no physical change to the plant that results in reduction of the RCS flow is made without the staff approval.

The licensee's proposed change to relocate the RCS MMF to the COLR is consistent with the STS and WCAP-14483-A. The existing TS limit value of $331,840 gpm corresponds to the MMF for the current RTP of 3114.4 MWt, which will be relocated to the COLR. For the SPU program, the MMF limit specified in the COLR will be updated to $348,300 gpm, which is consistent with the value used in the SPU safety analyses using the revised thermal design procedure (RTDP), and is acceptable. The proposed new value to be retained in the TS is the current RCS thermal design flow (TDF) of $322,800 gpm, which has not changed for SPU conditions. The NRC staff found the proposed changes to LCO 3.4.1, SR 3.4.1.3 and SR 3.4.1.4 by relocating the MMF to the COLR and retaining the minimum RCS flow limit to be acceptable. In addition, the revision to TS Bases B3.4.1 is consistent with the associated changes to LCO 3.4.1.c, SR 3.4.1.3 and SR 3.4.1.4.

4.6 TS 3.4.9 Pressurizer

For the SPU, the licensee proposed to change LCO 3.4.9 and SR 3.4.9.1 by increasing the pressurizer maximum water level limit from # 60.6% to # 65.1%. The TS Bases is also being changed to reflect this change. The maximum water level limit is specified to maintain a sufficient space for a steam bubble during normal operation and therefore accommodate

pressurizer insurge during heatup transients. This change reflects the pressurizer water level corresponding to the maximum value of T_{avg} of 572 EF supported by the SPU analyses.

For the SPU safety analyses of loss of feedwater and turbine trip events, which result in pressurizer insurge, the initial pressurizer level is assumed to be 71%. The results of these safety analyses demonstrated that the specified acceptable fuel design limits are not exceeded and the peak reactor system pressure remains below 110% of the design pressure. Therefore, maintaining the pressurizer level below 71% during normal operation is acceptable. Accounting for the allowance for instrument error of 5.9%, the indicated pressurizer level is limited to # 65.1%. The NRC staff finds this acceptable.

4.7 TS 3.5.1 Accumulator

For the SPU, the licensee proposed to change SR 3.5.1.4 by changing the accumulator boron concentration upper limit from # 2500 ppm to # 2600 ppm. The maximum boron concentration of the accumulators and RWST is used in post-LOCA long-term cooling in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH. The change of boron concentration limit from # 2500 ppm to # 2600 ppm provides flexibility and is consistent with the analysis. The maximum boron concentration for the boron sources is assumed for post-LOCA hot leg switchover time calculation. Section 6.2.4 of IP-2 SPU licensing report, WCAP-16157-P, indicated that 2600 ppm for the accumulators and RWST is used in the post-LOCA hot-switchover analysis. Therefore, the proposed change of SR3.5.1.4 upper boron concentration limit to # 2600 ppm is acceptable.

4.8 TS 3.5.4 RWST

For the SPU, the licensee proposed to change SR 3.5.4.1 by increasing the RWST borated water temperature upper limit from # 100 EF to # 110 EF, and change SR 3.5.4.3 by changing the RWST boron concentration range from “$ 2000 and # 2500 ppm” to "$ 2400 and # 2600 ppm.”

The increase in maximum RWST water temperature provides additional operational margin for RWST conditions that may be experienced in the summer months. The licensee states that the proposed new higher temperature is reflected in the SPU safety analyses. Section 6.2.1.1.13 of application indicates that the LOCA analysis in the analysis of record (AOR) used the maximum value of 120 EF for the safety-injection temperature. Therefore, the proposed RWST boron water temperature of 110 EF for the SPU program is bounded by the AOR value, and the proposed change to SR 3.5.4.1 is acceptable.

The proposed increase of the maximum boron concentration of the RWST from # 2500 ppm to # 2600 ppm is consistent with the post-LOCA hot-leg switchover analysis described in Section 6.2.4 of application and is, therefore, acceptable. The proposed increase of the minimum value of the acceptable boron concentration range from $ 2000 ppm to $ 2400 ppm is more restrictive than the existing value and is, therefore, acceptable.

4.9 TS 3.7.1 Main Steam Safety Valves (MSSVs)

The licensee proposed to revise the thermal power limits for Conditions A and B in LCO 3.7.1. For Condition A when one or more SGs with one MSSV inoperable, the licensee proposed to

revise the Required Action A.1 by reducing the thermal power to # 57% RTP from the current # 59% RTP. For Condition B when one or more SGs with two or three MSSVs inoperable, the licensee proposed to revise Table 3.7.1-1 by reducing the maximum allowable power with lower power limits for various number of MSSVs operable. The reduced thermal power levels is determined from a formula described in the TS Basis 3.7.1 based on the relief capacity and status of the MSSVs. The proposed changes to reduce the maximum allowable power levels specified in Action A.1 and Table 3.7.1-1 reflect new limits corresponding to the slightly higher steam flow at SPU conditions and are acceptable.

4.10 TS 5.6.5 Core Operating Limits Report (COLR)

The licensee proposed to revise the list of the analytical methods, specified in TS 5.6.5.b, used to determine the core operating limits. The revision includes the deletion of items 5 (WCAP-10266-P-A, Revision 2) and 6 (Caldon, Inc. Engineering Report 80P), and the addition of the following topical reports: WCAP-11397-P-A, WCAP-8745-P-A, WCAP-12610-P-A, WCAP-10079-P-A, WCAP-10054-P-A, and WCAP-10054-P-A, Addendum 2, Revision 1. The deletion of WCAP-10266-P-A and Caldon Engineering Report 80P is acceptable because they are no longer used in the IP2 SPU safety analysis. The addition of Westinghouse WCAP topical reports reflects the revised methods used in the non-LOCA transient analysis using the revised thermal design procedure, and the SBLOCA analysis using Westinghouse SBLOCA evaluation model with the NOTRUMP code. All the added topical reports to TS 5.6.5.b have been approved by the NRC and, therefore, are acceptable.

In its August 12, 2004, letter, the licensee also proposed to revise referencing of item 6, WCAP-12945, by including a Westinghouse letter and the NRC SE for approval of the best-estimate LBLOCA methodology with limitations for application to IP2. This change provides clear limitations regarding the use of the WCOBRA/TRAC code for the IP2 LBLOCA analysis, and, therefore, are acceptable.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. In a telephone call on October 26, 2004, the State official stated that the State does not oppose the approval of the power uprate application. In a subsequent electronic mail on October 27, 2004, the State Department of Environmental Conservation provided a summary of its review and issues about the impact from the uprate on terminal discharge to the Hudson River. These issues would be handled under its processing of a modified New York State Pollutant Discharge Elimination System discharge permit for Indian Point.

6.0 ENVIRONMENTAL CONSIDERATION

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 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 (69 FR 9859). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to

10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

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

8.0 REFERENCES

1. American Society for Materials and Testing (ASTM) Standard Practice E 185, “Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels.”

2. American Society of Mechanical Engineers (ASME), “Boiler and Pressure Vessel Code,” “Nuclear Vessels,” 1965 Edition, The American Society of Mechanical Engineers, New York, NY.

3. ASME Boiler and Pressure Vessel Code, “Nuclear Power Plant Components”, 1974 Edition and Winter Addenda, The American Society of Mechanical Engineers, New York, NY.

4. Westinghouse Electric Company Reports, WCAP-12945-P-A, Volume 1, Revision 2, and Volume 2 through 5, Revision 1, and WCAP-14747 (Non-proprietary), “Code Qualification Document for Best Estimate LOCA Analysis,” S. Bajorek, et al., 1998.

5. Westinghouse Corporation Power Systems letter, CLC-NS -309, dated April 1, 1975, C. L. Caso, Manager, Safeguards Engineering, to T. M. Novak, Chief, Reactor Systems Branch, NRC.

6. Westinghouse Reports, WCAP-9500, “Reference Core Report 17x17 Optimized Fuel Assembly,” S. L. Davidson, and J. A. Iorii, et al. May 1982; WCAP-9401-P-A, “Verification Testing and Analyses of the 17x17 Optimized Fuel Assembly,” M. D. Beaumont and J. Skaritka, et al., March 1979; and “Supplemental Acceptance Information for NRC Approved Version of WCAP-9401/9402 and WCAP-9500,” S. L. Davidson and J. A. Iorii, et al., February 1983.

7. NRC Letter, G. F. Dick , Jr., J. L. Skolds, Exelon Nuclear, dated September 27, 2002, “Hot Leg Switchover Confirmatory Analysis - Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2 (TAC Nos. MA5237, MA5238, MA5239, and MA5240.”

8. NRC Letter, G. F. Dick to O. D. Kingsley, Exelon Nuclear, dated May 4, 2001, “Issuance of Amendments; Increase in Reactor Power, Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (TAC Nos. MA9428, MA9429, MA9426, and MA9427.”

9. Entergy Nuclear Operations, Inc., (Entergy) Letter to NRC, NL-02-06, “Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation, Revision 1,” December 2001.

10. Entergy Letter to NRC, dated August 3, 2004, “Reply to Supplemental Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865),” with Attachments.

11. Indian Point Nuclear Generating Station Unit No. 2, Updated Final Safety Analysis Report, Docket No. 50-247.

12. Exelon Generation Letter, RS-02-065, dated April 12, 2002, K. R. Jury to NRC, “Hot Leg Switchover Confirmatory Analysis Supporting Uprated Power Operations at Byron and Braidwood Stations.”

13. NRC Letter, J. G. Lamb to T. Coutu, Nuclear Management Company, LLC, dated February 27, 2004, “Kewaunee Nuclear Power Plant - Issuance of Amendment Regarding Stretch Power Uprate (TAC No. MB9031).”

14. Entergy Letter, F. Damacio, Indian Point Energy Center (IPEC), to NRC, NL-04-005, dated January 29, 2004, “Proposed Changes to Technical Specifications: Stretch Power Uprate Increase of Licensed Thermal Power (3.26%).”

15. Entergy Letter, F. Damacio, IPEC, to NRC, NL-04-039, dated April 12, 2004, “Supporting Information for License Amendment Request Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865).”

16. Entergy Letter, F. Damacio, IPEC, to NRC, NL-04-073, dated June 16, 2004, “Reply to Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865).”

17. Entergy Letter, F. Damacio, IPEC, to NRC, NL-04-086, dated July 16, 2004, “Reply to Supplemental Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865).”

18. Entergy Letter, F. Damacio, IPEC, to NRC, NL-04-095, dated August 3, 2004, “Reply to Supplemental Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865).”

19. Entergy Letter, F. Damacio, IPEC, to NRC, NL-04-100, dated August 12, 2004, “Reply to Supplemental Request for Additional Information Regarding Indian Point 2 Stretch Power Uprate (TAC MC1865).”

20. NRC Letter, P. Milano to M. Kansler, Entergy, dated May 22, 2003, Issuance of Amendment No. 237 for Measurement Uncertainty Recapture (MUR) Power Uprate of 1.4 Percent for IP2 (TAC No. MB6950).

21. Westinghouse Letter, T. M. Anderson to S. H. Hanauer, NRC, NS-TMA-2182, dated December 30, 1979, ATWS Submittal.

22. NRC Letter, J. T. Munday to M. Kansler, Entergy, dated February 15, 2002, Issuance of Amendment No. 224 for IP2.

23. NRC Letter, J. Harold to S. E. Quinn, Consolidated Edison of new York, dated March 31, 1997, Issuance of Amendment for IP2 (TAC No. M96370).

24. NUREG-0800, "Standard Review Plan," Draft Revision, April 1996.

25. NRC Letter, B. M. Pham to G. R. Overbeck, Arizona Public Service Company, dated September 29, 2003, "Palo Verde Nuclear Generating Station, Unit 2 (PVNGS-2) - Issuance of Amendment on Replacement of Steam Generators and Uprated Power Operations (TAC No. MB3696)."

26. RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

27. RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," March 2001.

28. Title 10 of the *Code of Federal Regulations*, Part 50.

29. NRC Office of Nuclear Reactor Regulation Review Standard RS-001, "Review Standard for Extended Power Uprates," dated December 2003.

30. Westinghouse Report, WCAP-10054-P-A, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NORTRUMP Code: Safety Injection into the broken Loop and COSI Condensation Model, Addendum 2, Rev. 1," C. M. Thompson, et al., July 1997.

31. Westinghouse Reports, WCAP-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August 1985, and WCAP-11002, "Evaluation of Steam Generator Overfill Due to a Steam Generator Tube Rupture Accident," February 1986.

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

33. Westinghouse Report, WCAP-11394 (Proprietary), "Methodology for the Analysis of the Dropped Rod Event," R. L. Haessler, et al., April 1987.

34. Westinghouse Report, WCAP-11397-P-A, "Revised Thermal Design Procedure," A. J. Friedland and S. Ray, April 1989.

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

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

37. Westinghouse Report, WCAP-15063-P-A, “Westinghouse Improved Performance Analysis and Design Model (PAD 4.0),” Foster, Sidener, and Slagle, Revision, 1, with errata, July 2000.

38. Westinghouse Report, WCAP-15629, “Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation,” T. J. Laubhaum, Revision 1, December 2001.

39. Westinghouse Report, WCAP-15904-P, “Power Calorimetric Uncertainty for the 1.4 percent Uprating of Indian Point 2,” Revision 1, May 2003.

40. Westinghouse Report, WCAP-7588, “An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods,” Revision 1A, D. H. Risher, January 1975.

41. Westinghouse Report, WCAP-7769, “Overpressure Protection for Westinghouse Pressurized Water Reactors,” Revision 1, Salvatori, July 1972.

42. Westinghouse Report, WCAP-7908-A, “FACTRAN-A FORTRAN-IV Code for Thermal Transients in a UO2 Fuel Rod,” H. G. Hargrove, December 1989.

43. Westinghouse Report, WCAP-7907-P-A (Proprietary), “LOFTRAN Code Description,” W. Burnett, et. al., April 1984.

44. Westinghouse Report, WCAP-7979-P-A, “TWINKLE, A Multi-Dimensional Neutron Kinetics Computer Code,” R. F. Barry, Jr. and D. H. Risher, January 1975.

45. Westinghouse Report, WCAP-8963-P-A, “Safety Analysis for the Revised Fuel Rod Internal Pressure Design Basis,” August 1978.

46. Westinghouse Report, WCAP-9272-P-A (Proprietary), “Westinghouse Reload Safety Evaluation Methodology,” F. M. Bordelon, et al., July 1985.

47. Welding Research Council Bulletin (WRCB) 175, “PVRC [Pressure Vessel Research Committee] Recommendations on Toughness Requirements for Ferritic Materials,” October 2003.

48. Westinghouse Report, WCAP-10263, “A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant,” January 1993.

Principal Contributors:			
B. Elliot	J. Quichocho	G. Georgiev	P. Milano
J. Terrell	N. Trehan	H. Li	
J. Wu	L. Lois	M. Barillas	
F. Orr	W. Lyon	S. Wu	
G. Hsii	D. Reddy	J. Tatum	
R. Gallucci	M. Hart	R. Lobel	
J. Cushing	J. Cai	T. Tjader	

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Attachments: Tables 1 to 9
List of Acronyms

Table 1

Design Basis Accident Licensee Calculated Radiological Consequences TEDE[5] (rem)

Design Basis Accident	EAB[6]	LPZ[7]	Control Room
MSLB, Pre-existing iodine spike	0.12	0.13	0.18
Dose acceptance criteria[8]	25	25	5
MSLB, Accident-initiated iodine spike	0.12	0.33	0.52
Dose acceptance criteria	2.5	2.5	5
Locked Rotor Accident	0.24	0.54	0.65
Dose acceptance criteria	2.5	2.5	5
Control Rod Ejection Accident	3.1	4.2	1.4
Dose acceptance criteria	6.3	6.3	5
SGTR, Pre-existing spiking	3.24	1.52	1.36
Dose acceptance criteria	25	25	5
SGTR, Accident-initiated spiking	1.12	0.55	0.48
Dose acceptance criteria	2.5	2.5	5
SBLOCA, total	7.8	10.8	3.5
Dose acceptance criteria	25	25	5
LBLOCA, total	17.8	13.6	4.9
Dose acceptance criteria	25	25	5
FHA	4.2	2.0	3.0
Dose acceptance criteria	6.3	6.3	5

[5]Total Effective Dose Equivalent

[6]Exclusion Area Boundary, licensee reported as site boundary dose

[7]Low Population Zone

[8]Dose acceptance criteria taken from SRP 15.0.1 and GDC-19

Table 2

Assumptions for Main Steam Line Break Analysis

Reactor coolant activity	
Pre-existing iodine spike case	60.0 µCi/gm DE I-131[1]
Accident-initiated iodine spike case	1.0 µCi/gm DE I-131
Accident-initiated iodine appearance rate spiking factor	500 times equilibrium rate
Duration of accident-initiated iodine spike	3 hours
Secondary coolant activity	0.15 µCi/gm DE I-131
Primary coolant mass	486,000 lbm
Secondary coolant initial liquid mass	
Faulted steam generator (SG)	134,500 lbm
Intact SG	83,075 lbm/SG
Steam release from faulted SG	134,500 lbm
Time to release faulted SG initial mass	5 minutes
Steam release from intact SG	
0 - 2 hours	381,000 lbm
2 - 8 hours	830,000 lbm
8 - 30 hours	1,488,000 lbm
Time to cool RCS and stop faulted SG release	30 hours
Steam partition coefficient	
Faulted steam generator	1
Intact steam generator	0.01
Steam generator tube leak rate	150 gallons per day per SG
Time until begin control room emergency HVAC	1 minutes
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

[1]Dose Equivalent Iodine-131

Table 3

Assumptions for Locked Rotor Accident Analysis

Reactor power	3280.3 MWt
Reactor coolant activity	60.0 µCi/gm DE I-131
Secondary coolant activity	0.15 µCi/gm DE I-131
Primary coolant mass	486,000 lbm
Secondary coolant mass	315,164 lbm
Fuel rods in core failing	5%
No fuel melting	
Fission product gap fractions	
I-131	0.08
Kr-85	0.10
Other iodines and noble gases	0.05
Alkali metals	0.12
Radial peaking factor	1.7
Iodine chemical form in release	97% elemental, 3% organic
Primary-to-secondary SG tube leak rate	150 gallons per day per SG
Steam release from secondary	
0 - 2 hours	384,000 lbm
2 - 8 hours	860,000 lbm
8 - 30 hours	1,488,000 lbm
Steam partition coefficient, iodine	0.01
Time to cool RCS and stop steam release	30 hours
Time until begin control room emergency HVAC	21 minutes
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

Table 4

Assumptions for Rod Ejection Accident Analysis

Reactor power	3280.3 MWt
Reactor coolant activity	1.0 µCi/gm DE I-131
Secondary coolant activity	0.15 µCi/gm DE I-131
Primary coolant mass	486,000 lbm
Secondary coolant mass	315,164 lbm
Radial peaking factor	1.7
Fuel rods in core failing	10%
Fission product gap fractions	
Iodines and noble gases	0.10
Alkali metals	0.12
Fuel rods in core melting	0.25%
Fission product activity released from melted fuel	
Noble gases and alkali metals	100%
Iodines	25% for containment leakage path 50% for SG steaming path
SG steaming release pathway	
Primary-to-secondary SG tube leak rate	150 gallons per day per SG
Duration of leakage	1 hour
Steam release from secondary	
0 - 2 hours	400,000 lbm
> 2 hours	0 lbm
Steam iodine partition coefficient	0.01
Iodine chemical form in steam release	97% elemental, 3% organic
Containment leakage pathway	
Containment net free volume	2.61E+06 ft^3
Sedimentation removal in containment	
Particulate iodine	0.1 hr^{-1}
Containment leak rate	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Time until begin control room emergency HVAC	3 minutes
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

Table 5

Assumptions for Steam Generator Tube Rupture Analysis

Reactor coolant activity	
Pre-existing iodine spike case	60.0 µCi/gm DE I-131
Accident-initiated iodine spike case	1.0 µCi/gm DE I-131
Accident-initiated iodine appearance rate spiking factor	335 times equilibrium rate
Duration of accident-initiated iodine spike	4 hours
Secondary coolant activity	0.15 µCi/gm DE I-131
Primary coolant mass	486,000 lbm
Secondary coolant initial liquid mass	67,000 lbm/SG
Intact steam generator tube leak rate	150 gallons per day
Pre-trip releases (< 289.8 seconds)	
Tube rupture break flow	29,000 lbm
Percentage of break flow that flashes to steam	21%
Steam release to condenser	1075.55 lbm/sec for each SG
Post-trip releases (> 289.8 seconds)	
Tube rupture break flow	99,000 lbm
Percentage of break flow that flashes to steam	13%
Steam release from ruptured SG, 0 - 0.5 hours	77,300 lbm
Steam release from intact SG, 0 - 2 hours	542,000 lbm
Steam release from intact SG, 2 - 8 hours	1,090,000 lbm
Steam release from intact SG, 8 - 24 hours	1,760,000 lbm
Steam iodine partition coefficient	
Ruptured steam generator, break flow	1
Intact steam generator	0.01
Time until begin control room emergency HVAC	5.83 minutes
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

Table 6

Assumptions for SBLOCA Analysis

Reactor power	3280.3 MWt
Reactor coolant activity	1.0 µCi/gm DE I-131
Secondary coolant activity	0.15 µCi/gm DE I-131
Primary coolant mass	486,000 lbm
Secondary coolant mass	315,164 lbm
Radial peaking factor	1.7
Fuel rods in core failing	100%
Fission product gap fraction	
Iodine, noble gases and alkali metals	0.05
SG steaming release pathway	
Primary-to-secondary SG tube leak rate	150 gallons per day per SG
Duration of leakage	1 hour
Steam release from secondary	
0 - 2 hours	400,000 lbm
> 2 hours	0 lbm
Steam iodine partition coefficient	0.01
Iodine chemical form in steam release	97% elemental, 3% organic
Containment leakage pathway	
Containment net free volume	2.61E+06 ft^3
Sedimentation removal in containment	
Particulate iodine	0.1 hr^{-1}
Containment leak rate	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Time until begin control room emergency HVAC	3 minutes
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

Table 7

Assumptions for LBLOCA Analysis

Reactor power	3280.3 MWt
Source term	Based on RG 1.183
Containment volume	2.61E+06 ft^3
Containment leak rate	
0 - 24 hours	0.1 weight % per day
> 24 hours	0.05 weight % per day
Fan cooler flow rate	64,500 cfm/unit
Number of fan coolers credited	3
Sprayed fraction of containment	0.8
Spray operation	
Time to initiate sprays	1 minute
Spray injection duration	37.8 minutes
Termination of sprays	3.4 hours
Spray removal coefficients	
Elemental iodine	
Injection phase	20 hr^{-1}
Recirculation phase	5.0 hr^{-1}
Particulate iodine	
Injection phase	4.4 hr^{-1}
Recirculation phase	2.25 hr^{-1}
Sedimentation (after spray termination)	0.1 hr^{-1}
ECCS leakage	
Containment sump mass	3.12E+06 lbm
ECCS leak rate, 6.5 hours - 30 days	4 gal/hr
Airborne iodine fraction to auxiliary building (based on enthalpy)	
6.5 - 8 hours	0.120
8 - 24 hours	0.0855
24 - 96 hours	0.0523
96 - 720 hours	0.0300
Time until begin control room emergency HVAC	1 minute
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Emergency ventilation system flow rates	
Filtered makeup	1800 scfm
Unfiltered inleakage	700 scfm
Control room filter efficiencies	
Elemental	95%
Organic	90%
Particulate	99%
Atmospheric dispersion factors	Table 9

Table 8

Assumptions for Fuel Handling Accident Analysis

Reactor power	3280.3 MWt
Radial peaking factor	1.7
Fission product decay period	84 hours
Number of fuel assemblies damaged	1
Fuel gap fission product inventory	
I-131	12%
Kr-85	30%
Other iodines and noble gases	10%
Fuel pool water depth	23 ft
Pool iodine effective decontamination factor	200
Duration of release	2 hours
No isolation of control room HVAC assumed	
Normal ventilation flow rates	
Unfiltered makeup	920 scfm
Unfiltered inleakage	700 scfm
Atmospheric dispersion factors	Table 9

Table 9

Atmospheric Dispersion Factors

Exclusion Area Boundary (Site Boundary)

Time (hr)	X/Q (sec/m^3)
Duration	7.5E-04

Low Population Zone

Time (hr)	X/Q (sec/m^3)
0 - 2	3.5E-04
2 - 24	1.2E-04
24 - 48	4.2E-05
48 - 720	9.3E-06

Control Room

Time (hr)	Containment X/Q (sec/m^3)	MSLB SG X/Q (sec/m^3)	Non-LOCA Secondary X/Q (sec/m^3)	ECCS X/Q (sec/m^3)
0 - 2	3.82E-04	1.09E-03	9.49E-04	6.44E-04
2 - 8	2.81E-04	1.02E-03	8.65E-04	4.69E-04
8 - 24	1.05E-04	4.99E-04	4.17E-04	1.72E-04
24 - 96	8.31E-05	3.86E-04	3.30E-04	1.37E-04
96 - 720	7.04E-05	2.99E-04	2.54E-04	1.17E-04

LIST OF ACRONYMS

AAC	Alternate AC
AL	Analytical Limit
AMSAC	ATWS (anticipated transient without scram) Mitigating System Actuation Circuitry
AOO	Anticipated Operational Occurrence
AOP	Abnormal Operating Procedures
ARV	Atmospheric Relief Valve
ASME	American Society of Mechanical Engineers
AST	Alternate Source Term
ASTM	American Society for Testing and Materials
ATWS	Anticipated Transient Without Scram
AV	Allowable Value
BOP	Balance-of-Plant
BOL	Beginning-of-Life
BTP	Backfit Test Program
CCWS	Component Cooling Water System
CFR	*Code of Federal Regulations*
COLR	Core Operating Limit Report
CRDS	Control Rod Drive System
CRDM	Control Rod Drive Mechanism
CSA	Chemical Storage Area
CST	Condensate Storage Tank
CVCS	Charging Volume and Control System
DBA	Design-Basis Accident
DECL	Double-Ended Cold Leg
DNB	Departure from Nucleate Boiling
DSS	Diverse Scram System
ECCS	Emergency Core Cooling System

EDG	Emergency Diesel Generator
EFPY	Effective Full-Power Year
EOL	End-of-Life
EOP	Emergency Operating Procedure
EQ	Environmental Qualification
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
FAC	Flow-Accelerated Corrosion
FPP	Fire Protection Program
GDC	General Design Criterion
GDT	Gas Decay Tank
HELB	High-Energy Line Break
HFP	Hot Full-Power
HT	Holdup Tank
HVAC	Heating, Ventilation, and Air Conditioning
HZP	Hot Zero-Power
IGSCC	Intergranular Stress Corrosion Cracking
IOP	Interim Operating Procedure
ITS	Improved Technical Specifications
LBB	Leak-before-Break
LCO	Limiting Condition for Operation
LEFM	Leading Edge Flowmeter
LOCA	Loss-of-coolant Accident
LONF	Loss of Normal Feedwater
LTC	Long-Term Cooling
LTOP	Low-Temperature Overpressure Protection
MDAFWP	Motor-Driven Auxiliary Feedwater Pump

MMF	Minimum Measured Flow
MOV	Motor-Operated Valve
MSLB	Main Steamline Break
MSIV	Main Steam Isolation Valve
MSSV	Main Steam Safety Valves
MTC	Moderator Temperature Coefficient
MVA	Megavolts-ampheres
MUR	Measurement Uncertainty Recaputure
MWe	Megawatts Electric
MWt	Megawatts Thermal
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NR	Narrow Range
NSAL	Nuclear Safety Advisory Letters
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Management and Resources Council
P-T	Pressure-Temperature
PCT	Peak Cladding Temperature
PPC	Plant Process Computer
PPCS	Plant Process Computer Screen
ppm	Parts per Million
PORV	Power-Operated Relief Valve
psig	Pounds per Square Inch Guage
PSV	Pressurizer Safety Valve
PTS	Pressurized Thermal Shock
PWR	Pressurized-Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RAI	Request for Additional Information
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump

RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RIS	Regulatory Issue Summary
RPS	Reactor Protection System
RS	Regulatory Standard
RSG	Replacement Steam Generator
RTP	Rated Thermal Power
RTDP	Revised Thermal Design Procedure
RVHP	Reactor Vessel Head Penetration
RWST	Refueling Water Storage Tank
SAL	Safety Analysis Limit
SAT	Station Auxiliary Transformer
SBO	Station Blackout
SCC	Stress-Corrosion Cracking
SE	Safety Evaluation
SFP	Spent Fuel Pool
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SI	Safety Injection
SIS	Safety Injection Signal
SLB	Steamline Break
SPU	Stretch Power Uprate
SRP	Standard Review Plan
SR	Surveillance Requirement
SSC	Structure, System, and Component
SSE	Safe Shutdown Earthquake
STDP	Standard Thermal Design Procedure
SWS	Service Water System

TDF	Thermal Design Flow
TDAFWP	Turbine-Driven Auxiliary Feedwater Pump
TGSCC	Transgranular Stress Corrosion Cracking
UAT	Unit Auxiliary Transformer
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
USE	Upper-Shelf Energy
VCT	Volume Control Tank
WOG	Westinghouse Owners Group