ENT000653
Submitted: August 10, 2015

March 24, 2005

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

SUBJECT: INDIAN POINT NUCLEAR GENERATING UNIT NO. 3 - ISSUANCE OF AMENDMENT RE: 4.85 PERCENT STRETCH POWER UPRATE AND RELOCATION OF CYCLE-SPECIFIC PARAMETERS (TAC NO. MC3552)

Dear Mr. Kansler:

The Commission has issued the enclosed Amendment No. 225 to Facility Operating License No. DPR-64 for the Indian Point Nuclear Generating Unit No. 3 (IP3). The amendment consists of changes to the Technical Specifications (TSs) in response to your application transmitted by letter dated June 3, 2004, as supplemented by letters dated November 18, 2004, December 15, 2004 (2), and February 3 and 11, 2005.

The amendment revises the IP3 operating license and TSs to authorize an increase in the licensed rated thermal power by 4.85 percent from 3067.4 megawatts thermal (MWt) to 3216 MWt. In addition, the amendment also (1) relocates certain cycle-specific parameters from the TSs to the Core Operating Limits Report by adoption of TS Task Force (TSTF) Change Traveler No. TSTF-339, and (2) revises the allowable values (AVs) of certain reactor protection system and engineered safeguard features functions.

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. 50-286

Enclosures: 1. Amendment No. 225 to DPR-64
2. Safety Evaluation

cc w/encls: See next page

March 24, 2005

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

Docket No. 50-286
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2. Safety Evaluation
cc w/encls: See next page
Accession Number: ML050600380 Package: Tech Specs:

OFFICE	PDI-1/PM	PDI-1/LA	SPLB/SC	SPLB/SC	EMCB/SC	EMCB/SC	EEIB/SC	EEIB/SC
NAME	PMilano	SLittle	SWeerakkody	SJones	TChan	LLund	EMarinos	RJenkins
DATE	03/10/05	03/17/05	SE dtd 02/03/05	SE dtd 02/ 08 /05	SE dtd 01/25/05	SE dtd 02/ /05	SE dtd 01/26/05	SE dtd 01/26/05

OFFICE	EMEB/SC	SRXB/SC	SPSB/SC	IROB/SC	OGC	PDI-1/S C	PDI/D	DLPM/D
NAME	KManoly	DCoe	RDennig	DTrimble	SCole	RLaufer	CHolden	TMarsh
DATE	SE dtd 02/ 08 /05	SE dtd 02/ 08 /05	03/02/05	03/02/05	03/04/05	03/23/05	03/ 27/05	03/ 23/05

Official Record Copy

DATED: March 24, 2005

AMENDMENT NO. 225 TO FACILITY OPERATING LICENSE NO. DPR-64 INDIAN POINT UNIT 3

PUBLIC
PDI R/F
R. Laufer
P. Milano
S. Llittle
T. Boyce
G. Matakas, R-I
D. Coe
S. Jones
S. Weerakkody
M. Mitchell
T. Chan
L. Lund
E. Marinos
R. Jenkins
K. Manoly
R. Dennig
D. Trimble
J. Stang
OGC
G. Hill (2)
ACRS

cc: Plant Service list

Indian Point Nuclear Generating Unit No. 3

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 2
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 3
U. S. Nuclear Regulatory Commission
P.O. Box 337
Buchanan, NY 10511-0337

Indian Point Nuclear Generating Unit No. 3

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

ENTERGY NUCLEAR OPERATIONS, INC.

DOCKET NO. 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NO. 3

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 225
License No. DPR-64

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

   A. The application for amendment by Entergy Nuclear Operations, Inc. (the licensee) dated June 3, 2004, as supplemented by letters dated November 18 and December 15, 2004 (2), and February 3 and 11, 2005, 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-64 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 225, 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 shall be implemented within 30 days. Implementation shall include: (1) revisions to plant procedures and the completion of operator training on the proposed power uprate as described in the licensee's June 3, 2004, application, and (2) incorporation of the commitments as discussed in the NRC staff's safety evaluation dated March 24, 2005, into the licensee's Commitment Management Program.

FOR THE NUCLEAR REGULATORY COMMISSION

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: March 24, 2005

ATTACHMENT TO LICENSE AMENDMENT NO. 225

FACILITY OPERATING LICENSE NO. DPR-64

DOCKET NO. 50-286

Replace the following pages of the Facility Operating License 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 - 7	1 - 8

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
1.1-5	1.1-5
2.0-1	2.0-1
2.0-2	-----
3.3.1-13	3.3.1-13
3.3.1-15	3.3.1-15
3.3.1-19	3.3.1-19
3.3.1-20	3.3.1-20
3.3.2-8	3.3.2-8
3.3.2-11	3.3.2-11
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
3.7.1-3	3.7.1-3
5.0-31	5.0-31
5.0-34	5.0-34
5.0-35	5.0-35

ENTERGY NUCLEAR INDIAN POINT 3, LLC

AND ENTERGY NUCLEAR OPERATIONS, INC.

DOCKET NO. 50-286

INDIAN POINT NUCLEAR GENERATING UNIT NO. 3

AMENDED FACILITY OPERATING LICENSE

Amendment No. 203
License No. DPR-64

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

A. The application for amendment by the Power Authority of the State of New York (PASNY) and Entergy Nuclear Indian Point 3, LLC (ENIP3) and Entergy Nuclear Operations, Inc. (ENO), submitted under cover letters dated May 11 and May 12, 2000, as supplemented on June 13, June 16, July 14, September 21, October 26, and November 3, 2000, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as set forth in 10 CFR Chapter I; Amdt. 203 11/27/00

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. ENIP3 and ENO are financially and technically qualified to engage in the activities authorized by this amendment; Amdt. 203 11/27/00

E. ENIP3 and ENO have satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements" of the Commission's regulations; Amdt. 203 11/27/00

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

G. The receipt, possession and use of source, byproduct and special nuclear material as authorized by this amendment will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70 including 10 CFR Sections 30.33, 40.32, 70.23, and 70.31; and

H. 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, Facility Operating License No. DPR-64 (previously issued to Consolidated Edison Company of New York, Inc., and the Power Authority of the State of New York) is hereby amended in its entirety and transferred to ENIP3 and ENO on November 21, 2000, to read as follows: Amdt. 203 11/27/00

A. This amended license applies to the Indian Point Nuclear Generating Unit No. 3, a pressurized water nuclear reactor and associated equipment (the facility), owned by ENIP3 and operated by ENO. The facility is located in Westchester County, New York, on the east bank of the Hudson River in the Village of Buchanan, and is described in the "Final Facility Description and Safety Analysis Report" as supplemented and amended, and the Environmental Report, as amended. Amdt. 203 11/27/00

B. Subject to the conditions and requirements incorporated herein, the Commission licenses:

(1) Pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," (a) ENIP3 to possess and use, and (b) ENO to possess, use and operate, the facility at the designated location in Westchester County, New York, in accordance with the procedures and limitations set forth in this amended license; Amdt. 203 11/27/00

(2) ENO pursuant to the Act and 10 CFR Part 70, to receive, possess, and use, at any time, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Facility Description and Safety Analysis Report, as supplemented and amended; Amdt. 203 11/27/00

(3) ENO pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use, at any time, any byproduct source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required; Amdt. 203 11/27/00

(4) ENO pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; — Amdt. 203 11/27/00

(5) ENO pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility. — Amdt. 203 11/27/00

C. This amended license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

ENO is authorized to operate the facility at steady state reactor core power levels not in excess of 3216 megawatts thermal (100% of rated power).

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 225 are hereby incorporated in the License. ENO shall operate the facility in accordance with the Technical Specifications.

(3) (DELETED) — Amdt. 205 2-27-01

(4) (DELETED) — Amdt. 205 2-27-01

D. (DELETED) — Amdt.46 2-16-83

E. (DELETED) — Amdt.37 5-14-81

F. This amended license is also subject to appropriate conditions by the New York State Department of Environmental Conservation in its letter of May 2, 1975, to Consolidated Edison Company of New York, Inc., granting a Section 401 certification under the Federal Water Pollution Control Act Amendments of 1972.

G. ENO shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822), and to the authority of 10 CFR 50.90 and CFR 50.54(p). The combined set of plans[1] for the Indian Point Energy Center, which contain Safeguards Information protected under 10 CFR 73.21, is entitled: "Physical Security, Training and Qualification, and Safeguards Contingency Plan, Revision 0," and was submitted by letter dated October 14, 2004. — Letter of 10-28-04

H. ENO shall implement and maintain in effect all provisions of the approved Fire Protection Program as described in the Final Safety Analysis Report for Indian Point Nuclear Generating Unit No. 3 and as approved in NRC fire protection safety evaluations (SEs) dated September 21, 1973, March 6. 1979, May 2, 1980, November 18, 1982, December 30, 1982, February 2, 1984, April 16, 1984, January 7, 1987, September 9, 1988, October 21, 1991, April 20, 1994, January 5, 1995, and supplements thereto, subject to the following provision:

ENO may make changes to the approved Fire Protection Program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

I. (DELETED) — Amdt. 205 2/27/01

J. (DELETED) — Amdt. 205 2/27/01

K. (DELETED) — Amdt.49 5-25-84

L. (DELETED) — Amdt. 205 2/27/01

M. (DELETED) — Amdt. 205 2/27/01

14. (DELETED) — Amdt. 49 5-25-84

[1] The Training and Qualification Plan and Safeguards Contingency Plan are Appendices to the Security Plan.

O.	Evaluation, status and schedule for completion of balance of plant modifications as outlined in letter dated February 12, 1983, shall be forwarded to the NRC by January 1, 1984.	Amdt. 47 5-27-83
P.	Entergy Nuclear IP3 and ENO shall take no action to cause Entergy Global Investments, Inc. or Entergy International Ltd. LLC, or their parent companies to void, cancel, or modify the $70 million contingency commitment to provide funding for the facility as represented in the application for approval of the transfer of the license from PASNY to ENIP3 and ENO, without the prior written consent of the Director, Office of Nuclear Reactor Regulation.	Amdt. 203 11/21/00
Q.	The decommissioning trust agreement shall provide that the use of assets in the decommissioning trust fund, in the first instance, shall be limited to the expenses related to decommissioning of the facility as defined by the NRC in its regulations and issuances, and as provided in this license and any amendments thereto.	Amdt. 203 11/27/00
R.	The decommissioning trust agreement shall provide that no contribution to the decommissioning trust fund that consists of property other than liquid assets shall be permitted.	Amdt. 203 11/27/00
S.	With respect to the decommissioning trust fund, investments in the securities or other obligations of PASNY, Entergy Corporation, ENIP3, Entergy Nuclear FitzPatrick, LLC, ENO, or affiliates thereof, or their successors or assigns, shall be prohibited. Except for investments that replicate the composition of market indices or other non-nuclear-sector mutual funds, investments in any entity owning one or more nuclear plants is prohibited.	Amdt. 203 11/27/00
T.	The decommissioning trust agreement shall provide that no disbursements or payments from the trust, other than for ordinary administrative expenses, shall be made by the trustee until the	Amdt. 203 11/27/00

trustee has first given the NRC 30 days prior written notice of the payment. In addition, the trust agreement shall state that no disbursements or payments from the trust shall be made if the trustee receives prior written notice of objection from the Director, Office of Nuclear Reactor Regulation.

(21) The decommissioning trust agreement shall provide that the trust agreement shall not be modified in any material respect without the prior written consent of the Director, Office of Nuclear Reactor Regulation. — Amdt. 203 11/27/00

V. The decommissioning trust agreement shall state that the trustee, investment advisor, or anyone else directing the investments made in the trust shall adhere to a "prudent investment" standard, as specified in 18 CFR 35.32(a)(3) of the Federal Energy Regulatory Commission's regulations. — Amdt. 203 11/27/00

W. For purposes of ensuring public health and safety, ENIP3, upon the transfer of this license to it, shall provide decommissioning funding assurance for the facility by the prepayment or equivalent method, to be held in a decommissioning trust fund for the facility, of no less than the amount required under NRC regulations at 10 CFR 50.75. Any amount held in any decommissioning trust maintained by PASNY for the facility after the transfer of the facility license to ENIP3 may be credited towards the amount required under this paragraph. — Amdt. 203 11/27/00

X. ENIP3 shall take all necessary steps to ensure that the decommissioning trust is maintained in accordance with the application for the transfer of this license to ENIP3 and ENO and the requirements of the order approving the transfer, and consistent with the safety evaluation supporting such order. — Amdt. 203 11/27/00

AA. The following conditions relate to the amendment approving the conversion to Improved Standard Technical Specifications: — Amdt. 205 2/27/01

1. This amendment authorizes the relocation of certain Technical Specification requirements and detailed information to licensee-controlled documents as described in Table R, "Relocated Technical Specifications

from the CTS," and Table LA, "Removed Details and Less Restrictive Administrative Changes to the CTS" attached to the NRC staff's Safety Evaluation enclosed with this amendment. The relocation of requirements and detailed information shall be completed on or before the implementation of this amendment.

2. The following is a schedule for implementing surveillance requirements (SRs):

   For SRs that are new in this amendment, the first performance is due at the end of the first surveillance interval that begins on the date of implementation of this amendment.

   For SRs that existed prior to this amendment whose intervals of performance are being reduced, the first reduced surveillance interval begins upon completion of the first surveillance performed after the date of implementation of this amendment.

   For SRs that existed prior to this amendment that have modified acceptance criteria, the first performance is due at the end of the first surveillance interval that began on the date the surveillance was last performed prior to the date of implementation of this amendment.

   For SRs that existed prior to this amendment whose intervals of performance are being extended, the first extended surveillance interval begins upon completion of the last surveillance performed prior to the date of implementation of this amendment.

AB. With the reactor critical, Entergy shall maintain the reactor coolant system cold leg at a temperature (T_{cold}) greater than or equal to 525 EF. Entergy shall maintain a record of the cumulative time that the plant is operated with the reactor critical while T_{cold} is below 525 EF. Upon determination by Entergy that the cumulative time of plant operation with the reactor critical while T_{cold} is below 525 EF has exceeded one (1) year, Entergy must:

   (a) within one (1) month, inform the NRC, in writing, and

   (b) within six (6) months submit the results of an analysis of the impact of the operation with T_{cold} below 525 EF on the pressurized thermal shock reference temperature (RT_{PTS}).

3. This amended license is effective at 12:01 a.m., November 21, 2000, and shall expire at midnight December 12, 2015.

Original signed by

Robert W. Reid, Chief
Operating Reactors Branch #4
Division of Operating Reactors

Attachment: Changes to the Technical Specifications

Date of Issuance: March 8, 1978

Indian Point Nuclear Generating Unit No. 3

Safety Evaluation for Amendment No. 225

Regarding 4.85% Stretch Power Uprate and

Adoption of TSTF-339

TABLE OF CONTENTS

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 225 TO FACILITY OPERATING LICENSE NO. DPR-64

ENTERGY NUCLEAR OPERATIONS, INC.

INDIAN POINT NUCLEAR GENERATING UNIT NO. 3

DOCKET NO. 50-286

1.0 INTRODUCTION

By application dated June 3, 2004 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML041620506), as supplemented on November 18 and December 15, 2004 (2 letters), and February 3 and 11, 2005 (ADAMS Accession Nos. ML043290360, ML0043570326, and ML050380498), Entergy Nuclear Operations, Inc. (the licensee), submitted a request for changes to the Indian Point Nuclear Generating Unit No. 3 (IP3) Technical Specifications (TSs). The proposed amendment would increase the licensed reactor core thermal power level by 4.85 percent from 3067.4 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 proposed amendment would also (1) relocate cycle-specific parameters from the TSs to the Core Operating Limits Report (COLR), a licensee-controlled document, by adopting TS Task Force (TSTF) Traveler No. TSTF-339 and (2) revise the allowable values (AVs) of certain reactor protection system (RPS) and engineered safeguard features (ESF) functions.

Specifically, the following are the proposed changes:

1. The rated thermal power (RTP) on page 3 of the Facility Operating License would change from 3067.4 MWt to 3216 MWt.

2. RTP value in TS Section 1.1 would be changed from 3067.4 MWt to 3216 MWt.

3. Reactor Core Safety Limits in TS Section 2.1.1:

   - Relocating updated Figure 2.1-1 (Reactor Core Safety Limits) to the COLR

   - Adding new requirements 2.1.1.1 and 2.1.1.2 for departure from nucleate boiling (DNB) and peak fuel centerline temperature limits, respectively

   - Related Bases changes as specified in TSTF-339

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

   - Function 2.a, Power Range Neutron Flux (high). The AV would change from # 109% RTP to = 111%

   - Function 7.a, Pressurizer Pressure-low. The AV would change from š 1790 psia to = 1900 psia

   - Function 5, Note 1, Overtemperature ªT. The AV in Note 1 for this function would change from 5.8% to 2.8% in terms of ªT span. Note 1 is also being revised to reflect adoption of TSTF-339, which relocates parameters to the COLR and expresses the safety analysis limit (SAL) in terms of ªT span

   - Function 6, Note 2, Overpower ªT. The AV in Note 2 for this function would change from 3.7% to 1.8% in terms of ªT span. Note 1 is also being revised to reflect adoption of TSTF-339, which relocates parameters to the COLR and expresses the SAL in terms of ªT span

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

   - Function 1.d, Pressurizer Pressure-low. The AV would change from š 1690 psig to š 1710 psig

   - Function 1.f, High Steam Flow - Safety Injection, Coincident with Tavg-low. The AV would change from š 538 EF to š 540.5 EF

   - Function 4.d, High Steam Flow - Steam Line Isolation, Coincident with Tavg-low. The AV would change from š 538 EF to š 540.5 EF

6. Revise Reactor Coolant System (RCS) DNB Limits (TS Section 3.4.1):

   The proposed changes reflect the Minimum Measured Flow (MMF) change from 375,600 gpm to 364,700 gpm and the Thermal Design Flow (TDF) change from 323,600 gpm to 354,400 gpm supported by stretch power analysis. The 2.9% margin between the revised MMF (364,700 gpm) and TDF (354,400 gpm) properly represents the calculated instrument channel uncertainty associated with flow indication.

7. Revise the limiting condition for operation (LCO) and surveillance requirement (SR) limit for maximum pressurizer water level (TS 3.4.9):

   The proposed changes reflect 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. Limits for the Main Steam Safety Valves (MSSVs) RTP value in TS Section 3.7.1 would be changed to reflect new limits corresponding to the slightly higher steam flow at SPU conditions. Corresponding changes are needed for Bases 3.7.1.

9. Revise Containment Leakage Rate Testing Program (TS 5.5.15)

   The proposed changes reflect the peak accident containment pressure for the design-basis loss-of-coolant accident (DBLOCA) from 38.77 psig to 42.0 psig for SPU conditions.

10. Revise references for the COLR (TS 5.6.5)

    The proposed change adds the following three specifications as a result of adopting TSTF-339 for the relocation of parameters to the COLR:

    - Technical Specification 2.1, Safety Limits (SL)
    - Technical Specification 3.3.1, Reactor Protection System Instrumentation
    - Technical Specification 3.4.1, RCS Pressure, Temperature, and Flow from DNB Limits

The November 18 and December 15, 2004 (2 letters), and February 3 and 11, 2005, 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* (FR) on August 31, 2004 (69 FR 53105).

2.0 BACKGROUND

Nuclear power plants are licensed to operate at a specified core thermal power. IP3 was initially licensed to operate at a maximum power level of 3025 MWt. However, various systems and components were designed to accommodate the conditions associated with a power level of 3216 MWt. On November 26, 2002, the NRC staff approved a 1.4% measurement uncertainty recapture power uprate, which allowed an increase in the licensed power level from 3025 MWt to 3067.4 MWt by license amendment No. 213. The proposed SPU of 4.85% will allow the licensed rated power to be increased from the current value of 3067.4 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 June 3, 2004, application, as supplemented on November 18 and December 15, 2004 (2 letters), and February 3 and 11, 2005, was reviewed for compliance with the IP3 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 conducted a review of the RPS, the 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. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on Sections 50.55a(a)(1) and 50.55a(h) of Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR Part 50), and General Design Criteria (GDC) 1, 4, 13, 19, 20, 21, 22, 23, and 24 in Appendix A to 10 CFR Part 50. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Nuclear power plants are licensed to operate at a specified steady-state 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 and guidance related to this review can be found in 10 CFR Part 50 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 technical specification 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.

- NRC Regulatory Guide (RG) 1.105, Revision 3, "Setpoint for Safety-Related Instrumentation," provides one method of showing conformance with 10 CFR 50.36.

3.1.2 Technical Evaluation

3.1.2.1 Suitability of Existing Instruments

The IP3 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 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 IP3 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 AV changes in some of the reactor trip and ESFAS functions to support SPU power level conditions. However, IP3 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 lb/hr to 4.3 million lb/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 licensee has also replaced seven isolators and one summing module in the pressurizer pressure (four isolators), pressurizer level (three isolators), and Tavg (one summer) monitoring loops to maintain required accuracy for operations and for surveillance of system parameters to ensure compliance with the initial conditions assumed in various accident and transient safety analyses. The NRC staff considers that these modifications are for operational improvement and do not affect TSs or protection system configuration, and therefore, are acceptable.

3.1.2.2 Instrument Setpoints Methodology

The proposed amendment reflects instrument setpoint changes consistent with a requested thermal power uprate for IP3 from 3067.4 MWt to 3216 MWt. In response to the staff's request for additional information (RAI) on the instrument setpoint methodology, the licensee provided information and clarifications in a supplemental letter dated December 15, 2004. The setpoint methodology used to calculate trip setpoints and AVs of the plant parameters affected by the IP3 SPU basically is the same as used for IP2 SPU calculation. The more conservative value of the "check calculation" is adopted as the proposed licensed AV.

As discussed in IP2 setpoint methodology review, 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 (see IP2 SE dated October 27, 2004, ADAMS No. ML042960007). 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. For the IP3 SPU application, the check calculation has been included for AV determination. Therefore, in practice, Instrument Society

of America Standard RP67.04 (ISA-RP67.04), Part II, Method 2, has been applied to all IP3 power uprate related AV determination.

The NRC staff finds that IP3 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 the guidance of RG 1.105.

3.1.2.3 Instrumentation and Control 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 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 #109% RTP to #111% RTP. The Safety Analysis Limit (SAL), 118%, is not being changed for power uprate. By letter dated November 18, 2004, the licensee provided additional information regarding the IP3 nuclear instrumentation system (NIS) excore power range bistable/instrument uncertainty calculation. The proposed new AV of 111% is justified by site-specific instrument loop uncertainties and use of this value provides additional margin for as found surveillance testing of this instrument channel. The submittal provides a detailed calculation of the setpoint of this trip function 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 the guidance of 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 DNB ratio (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. There are many cycle-specific constants in the OT ªT function. The proposed amendment would relocate the values of these constants to the COLR (as discussed in Section 4.0 of this SE), and the trip setpoint described in Note 1 of TS Table 3.3.1-1 is calculated by ªT multiplied by these constants. The AV of the OT ªT function is specified as the percentage of the ªT span that the channel maximum trip setpoint may exceed its computed trip setpoint. By letter dated November 18, 2004, the licensee provided additional information regarding the IP3 Overtemperature ªT reactor trip uncertainty calculation. The submittal provides a detailed calculation of the setpoint of this trip function 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 guidance of 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. There are many cycle-specific constants in

the OP ªT function. The proposed amendment would relocate the values of these constants to the COLR, and the trip setpoint described in Note 2 of TS Table 3.3.1-1 is calculated by ªT multiplied by cycle-specific constants. The AV of the OP ªT function is specified as the percentage of the ªT span. By letter dated November 18, 2004, the licensee provided additional information regarding the IP3 Overpower ªT reactor trip uncertainty calculation. The submittal provides a detailed calculation of the setpoint of this trip function 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 guidance of RG 1.105, and therefore, is acceptable.

(4) Function 7.a, “Pressurizer Pressure - Low”

The “Pressurizer Pressure - Low” trip function ensures that protection is provided against violating the DNBR limit due to low RCS pressure. For the IP3 low pressurizer pressure reactor trip function, the nominal trip setpoint (NTS), SAL, and AV were changed in order to generate OT ªT and OP ªT reactor trip SALs that were as similar as possible between IP2 and IP3 for the SPU conditions. The licensee proposed to change the trip AV from 1790 psig to 1900 psig. For the SPU, the SAL for this trip function is increased from 1735.3 psig to 1835.3 psig to provide margin for the hot zero-power MSLB safety analysis. By letter dated November 18, 2004, the licensee provided additional information regarding the IP3 pressurizer pressure reactor trip uncertainty calculation. Based on the SAL value of 1835.3 psig, the calculated NTS is 1900 psig, and the AV is 1897 psig. For the purpose of being more closely aligned with the IP2 NTS for this function, the licensee chose the values of 1930 psig and 1900 psig for the NTS and AV, respectively. Since these NTS and AV are more conservative than the calculated values, the NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and guidance of RG 1.105, and therefore, is acceptable.

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

(1) Function 1.d, “Safety Injection by Pressurizer Pressure - Low”

For the IP3 low pressurizer pressure SI function, the NTS and AV were changed to more closely align the IP3 values with those of IP2 and to provide more traditional bottom of scale margin for the setpoint. The licensee proposed to change the trip AV from 1690 psig to 1710 psig. By letter dated November 18, 2004, the licensee provided additional information regarding the IP3 pressurizer pressure SI actuation uncertainty calculation. Based on the more conservative ISA-RP67.04 Method 2 calculation, the AV is determined to be 1695.36 psig. Since this calculated AV is below the bottom of scale of the pressurizer pressure instrument loops, which is 1700 psig, the licensee proposed an AV of 1710 psig, which is above the bottom of the instrument span. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and guidance of RG 1.105, and therefore, is acceptable.

(2) 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 SI 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 $538 ßF to $540.5 ßF. By letter dated November 18, 2004, the licensee provided additional information

regarding the IP3 T_{avg}-Low SI and steam line isolation actuation uncertainty calculation. With the T_{avg}-Low SAL of 535.0 ^{B}F, the calculated AV is 536.4 ^{B}F, based on conservative ISA-RP67.04 Method 2. Since this calculated AV is less than the bottom of the instrument span (540 ^{B}F) for this channel, the licensee proposed the AV to be 540.5 ^{B}F, which is above the bottom of the instrument span. The NRC staff finds that the setpoint calculation meets the requirements of 10 CFR 50.36 and guidance of RG 1.105, and therefore, is acceptable.

3.1.2.4 Conformance with GDC

Because the IP3 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 IP3 licensing basis. Although IP3 was not required to meet Appendix A to 10 CFR Part 50, the New York Power Authority (the former licensee for IP3) completed a study of the method by which IP3 complied with the safety rules and regulations, in particular those in 10 CFR Parts 20 and 50, that were in effect at the time of the study. The study was conducted in accordance with the Commission's Confirmatory Order of February 11, 1980, and submitted it to the NRC on August 11, 1980. The GDC which formed the bases for IP3 was published by the Atomic Energy Commission on July 11, 1967. The NRC audit of submittal indicated that the IP3 design and operation meet the applicable regulations. The results of the compliance are documented in the Section 1 of the IP3 Final Safety Analysis Report (FSAR). For this reason, the NRC staff evaluated the licensee's power uprate application to the requirements in the GDC's as described in the FSAR.

3.1.3 Summary

Based on the review of the IP3 SPU submittals, the NRC staff finds that the IP3 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 meets 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 IP3 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 proposed operation at 3216 MWt. The staff performed its review in accordance with NRC Review Standard RS-001, Revision 0, "Review Standard for Extended Power Uprate," December 2003 (ADAMS No. ML033640024), 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 SE sections. Each of these sections describes the applicable regulatory requirements and acceptance criteria, the licensee's analyses or evaluations, and the staff's conclusions. A detailed discussion about the codes and methodologies used in the SPU application can be found in Section 3.2.2.11 of this SE. The NRC staff also used the SRP, NUREG-0800, in performing its review (Reference 1).

Section 1.3 of IP3's Final Safety Analysis Report (Reference 2), lists the applicable regulatory requirements based on the GDC proposed in 1967 to which the plant was licensed.

3.2.2 Technical Evaluation

3.2.2.1 Nuclear Steam Supply System Parameters

The Nuclear Steam Supply System (NSSS) design parameters provide the reactor coolant system (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 power uprate application report, WCAP-16212-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 an increased core power level of 3216 MWt core power with a high value of 14 MWt net heat input from the reactor coolant pumps, decrease in the core inlet temperature, lower maximum steam pressure, lower maximum steam temperature, higher steam flow rate and zero and 10 percent SG tube plugging. 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 conditions at the proposed core power level of 3216 MWt.

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 will decrease from 375,600 gallons per minute (gpm) to 364,700 gpm. The thermal design flow (TDF) will increase from 323,600 gpm to 354,400 gpm. These changes increase the margin for DNB-related accidents and transients. The 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 to the 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

The licensee determined the required volume, duration, and heat rejection capability of the Safety Injection System (SIS) and Containment Spray System (CSS) in the event of a postulated accident based on analytical models that simulate reactor and containment conditions subsequent to the postulated RCS and Main Steam System breaks under SPU conditions. The high-head safety injection (HHSI) and low-head safety injection (LHSI) system flow performance was also calculated in support of the SPU accident analyses, including operation during the longer recirculation phase. The licensee determined that the HHSI system required higher hot leg recirculation flow performance for the SPU condition, while maintaining the maximum allowable HHSI pump flow limits. As a result, the HHSI system was modified by permanently closing two cold-leg injection lines and throttling the HHSI system to provide higher cold leg and hot leg flows. The HHSI system performance analysis also considered the recirculation sump particle criteria and the system throttle valve cavitation issues. In response to a staff RAI, the licensee stated that manual valves 856A and 856F will be permanently closed valves and will be administratively controlled by changing the normal position to locked

closed. The licensee applied the limiting single failure and spilling line assumptions in calculating the HHSI system flow performance data and confirmed that the failure analysis described in the FSAR was not affected. This HHSI flow performance data was used in the various accident analyses performed in support of the IP3 SPU program. The LHSI system also required higher cold leg recirculation flow due to the SPU and was modified for the recirculation phase of operation by re-throttling of the LHSI system butterfly valves. The licensee concluded the results demonstrated that SIS and CSS provide adequate safety margin, making these systems acceptable for the proposed SPU conditions. The licensee also concluded that the flow performance of CSS, HHSI and LHSI systems determined for the SPU are acceptable since the systems continue to provide adequate safety margin. The NRC staff agrees with the licensee's assessment since the regulatory requirements for the SIS and CSS as stated in IP3's FSAR Chapter 6 (GDC 44 and 52) continue to be met.

3.2.2.4 Residual Heat Removal 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 residual heat removal (RHR) system for plant cooldown. As per 10 CFR Part 50, Appendix R cooldown requirements, there is a 72-hour cooldown time to remove decay heat (Reference 3). For the various cases under SPU conditions, the licensee determined the minimum component cooling water (CCW) heat exchanger service water flow to meet the 72-hour cooldown time requirement. The licensee confirmed that the RHR and CCW systems continue to meet their design basis functional requirements and are capable of removing the decay heat under SPU conditions, 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 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 NRC 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(b)(5) 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.

IP3 is currently operating in Cycle 13 with 15 x 15 VANTAGE+ fuel assemblies. Commencing in Cycle 14, the licensee plans to refuel with a 15 x 15 upgraded fuel assembly with modified fuel rod support surfaces of the mid-grids and intermediate flow mixing (IFM) grids to enhance margin to grid-to-rod fretting. 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 4). 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 the IP3 SPU application (Reference 5). 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 analysis using the approved methodology, the NRC staff finds that the rod internal pressure analysis is acceptable for IP3 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 realized 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 anticipated operational occurrences (AOOs). The licensee established a corrosion limit and a hydriding pickup limit whic, if exceeded, could enhance corrosion. These limits were described in the approved PAD 4.0 computer code. The cladding corrosion will conceivably increase during SPU conditions. The licensee performed a bounding analysis using PAD 4.0, which showed that the maximum corrosion and hydriding were within the established limits under SPU conditions. Based on the results of the acceptable analysis, the NRC staff concludes that the impact of corrosion on the thermal and mechanical performance will be minimal for IP3 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 acceptable analysis, the NRC staff concludes that the strain fatigue capability is acceptable for IP3 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-analyzed the stress and strain conditions using the approved PAD 4.0 code and demonstrated that the stress and strain limits were not exceeded for SPU conditions. Therefore, the NRC staff concludes that the fuel system design meets the stress and strain limits for IP3 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 IP3 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 NRC-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 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 IP3 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 NRC 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 evaluation, the NRC staff determined that the fuel system and associated analyses will continue to meet the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed SPU is acceptable with respect to the fuel system design.

3.2.2.6 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 NRC staff's review covers core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worth, and criticality. 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 condition of 3216 MWt. The licensee used the approved Westinghouse core reload methodology (WCAP-9272-P-A) with the PHOENIX-P and ANC approved models to evaluate the nuclear design of the VANTAGE 15 x15 upgraded fuel design (Reference 7). The licensee modeled conceptual core loading patterns to be representative of future IP3 cores. The licensee demonstrated the results of key safety parameters listed in Table 7.3-1 of the application report and 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 SE methodology. 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 NRC staff concludes that the licensee adequately accounted for the effects of the proposed SPU 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 NRC staff determined 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 concludes that the proposed uprate is acceptable with respect to the nuclear design.

3.2.2.7 Thermal and Hydraulic Design Evaluation

The NRC staff reviews the thermal and hydraulic design of the core and the reactor coolant system 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 in GDC 10 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.

A DNBR reanalysis was required to define new core limits, axial offset limits, and Condition II accident acceptability to support the operation of IP3 at SPU conditions. The thermal-hydraulic design criteria and methods for the SPU remained the same as those presented in the IP3 FSAR and are, therefore, approved by NRC for use at IP3. 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. The Standard Thermal Design Procedure (STDP) and Revised Thermal Design Procedure (RTDP) were used in the analyses. In its November 18, 2004, letter, 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. The loss of flow, locked rotor, feedwater malfunction, dropped rod, steamline break and rod withdrawal from subcritical condition were analyzed for DNB as part of the SPU. These areas are addressed in more detail in Section 3.2.2.11 of this SE. In summary, the specified fuel design limits were not exceeded.

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 NRC 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 NRC staff determined 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 concludes that the proposed stretch power uprate is acceptable with respect to thermal and hydraulic design.

3.2.2.8 Functional Design of Control Rod Drive System

The NRC staff's review covers the functional performance of the 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, control rod drive mechanism (CRDM), rod travel housing, and the RCCA/drive rod assembly. The system operating conditions included temperature, pressure, and flow of the plant's driveline configuration. The licensee used the method consistent with the analysis of record, 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 1.95 seconds, which satisfies the current IP3 TS limit of 2.7 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 NRC 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.

3.2.2.9 Overpressure Protection During Power Operation

Overpressure protection for the 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 and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP, Section 5.2.2. 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. Based on the acceptable results of the safety analyses for overpressurization events addressed in Section 3.2.2.12 below, the NRC staff concludes that the licensee adequately accounted for the effects of the proposed power uprate on pressurization events and overpressure protection features. The NRC staff determined 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 concludes that the proposed stretch power uprate is acceptable with respect to overpressure protection during power operation.

3.2.2.10 Overpressure Protection During Low Temperature Operation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure relieving systems that function during the low temperature operation. 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 and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

The overpressure protection system at IP3 only comes into operation during zero-power operation during plant heatup, cooldown, or any operation between cold shutdown and hot standby. The licensee evaluated the overpressure protection system setpoints under SPU conditions and determined that the setpoints are not affected by the SPU. The NRC staff reviewed the licensee's methodology and vessel fluence values derived for use in 10 CFR Part 50, Appendix G, calculation of pressure temperature (PT) limit curves for normal heatup and cooldown. The NRC staff determined that the fluence values are acceptable because the calculation used an approved methodology and the values are supported by plant specific measurements. The licensee determined no changes were necessary to the PT limits. The NRC staff agrees since the values remained bounded by the existing values.

The NRC staff reviewed the licensee's evaluation related to the effects of the proposed SPU on the overpressure protection capability of the plant during low temperature operation. The NRC staff concludes that the low temperature overpressure protection features currently in place will continue to provide adequate protection following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed SPU is acceptable with respect to overpressure protection during low temperature operation.

3.2.2.11 Transient and Accident Analyses

The licensee reanalyzed the FSAR Chapter 14 LOCA and non-LOCA transients and accidents in support of the IP3 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 IP3 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 licensee used the RTDP in performing its uncertainty analysis. The uncertainty analysis used the SRSS technique to combine the uncertainty components of an instrument channel in an appropriate combination of those components, or groups of components, that are statistically independent. 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 NRC staff's review of the FSAR LOCA and non-LOCA transients and accidents is discussed in the following sections.

3.2.2.11.1 LOCA Analyses

In the June 3, 2004, application, as supplemented by letters dated November 18 and December 15, 2004 (2 letters), and February 3, 2005, the licensee provided IP3 large-break LOCA (LBLOCA) and small-break LOCA (SBLOCA) analyses performed at the uprated power for IP3 operating with a core consisting of 15x15 Westinghouse Vantage+ (ZIRLO-clad fuel) assemblies co-resident in the IP3 core with upgraded 15x15 Vantage+ fuel assemblies. The upgraded fuel assemblies are similar geometry to the previously existing co-resident fuel assemblies. Therefore, it was not necessary to include a mixed core penalty in the analyses. The licensee provided the LBLOCA and SBLOCA analyses results for the upgraded Vantage+ fuel in a letter dated December 15, 2004. The SBLOCA analyses results were explicitly calculated using the Westinghouse SBLOCA methodology described in the NORTRUMP (COSI) SBLOCA methodology. The licensee also provided the results of the SBLOCA

analyses in its December 15, 2004, letter. The NRC staff reviewed these analyses to assure that the licensee met the requirements of 10 CFR 50.46(b).

By letter dated December 15, 2004, the licensee provided the LOCA plant-specific analyses results for the upgraded Westinghouse Vantage+ fuel. Table 1 provides the licensee's LBLOCA analysis results.

TABLE 1 - LBLOCA

Limiting break Size/location	LBLOCA
Fuel Type	Westinghouse Vantage+ fuel with ZIRLO (both upgraded and co-resident)
Peak Cladding Temperature (PCT)	1944 ^{o}F *
Maximum Local Oxidation	< 7.6% **
Maximum Total Core-Wide Hydrogen Generation (All Fuel)	(0.620%) **

* The PCT results reported in the December 15, 2004, letter are for the limiting fuel only because both fuels are geometrically alike. The PCT values given in the table reflect that no mixed-core penalty is required.

** These LBLOCA local oxidation and core-wide hydrogen generation values are from the December 15, 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 IP3 in its December 15, 2004, letter. The licensee performed the analyses using the Westinghouse NOTRUMP (with COSI) SBLOCA methodology. The following table provides the licensee's SBLOCA analysis results.

TABLE 2 - SBLOCA

Limiting Break Size/Location	3-inch Pump Discharge
Fuel Type	Westinghouse Vantage+ fuel with ZIRLO
PCT	1543 °F *
Maximum Local Oxidation	0.02% **
Maximum Total Core-wide Oxidation (All Fuel)	<<1.0% **

* The PCT results reported in the December 15, 2004, letter are for the limiting fuel only because both fuels are geometrically alike. The PCT values given in the table reflect that no mixed-core penalty is required.

** These LBLOCA local oxidation and core-wide hydrogen generation values are from the December 15, 2004, letter, and are bounding values used for both fuels. The local oxidation value does not include pre-LOCA oxidation. The licensee states that operational controls are such that the total oxidation will always be below 15%.

These calculated values given in the tables above are less than the limits specified in 10 CFR 50.46(b) (1)-(3), which requires the PCT to be less than 2200 °F, the maximum cladding oxidation to be less than 17 percent, 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)-(3). Additionally, the licensee, as discussed below in Section 3.2.2.11.1.5, demonstrated compliance with 10 CFR 50.46(b)(5). In as much as no other consideration affects the IP3 core geometry, this assures that the IP3 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 are applicable to IP3, and demonstrate that IP3 complies with the requirements of 10 CFR 50.46 (b)(1)-(5). Therefore, the NRC staff concludes that the licensee's LOCA analyses are acceptable.

3.2.2.11.1.1 Mixed Core LOCA Analyses

As discussed above, the licensee's LBLOCA and SBLOCA analyses acceptably do not include a mixed core penalty.

3.2.2.11.1.2 Overall Applicability of LOCA Analysis Methodologies

Westinghouse Report WCAP-12945-P-A was approved by the NRC for application to Westinghouse 3- and 4-loop designs. Therefore, the Westinghouse LBLOCA methodology described in WCAP-12945 specifically applies to IP3 because IP3 is a plant of Westinghouse 4-loop design.

In a letter dated November 18, 2004, the licensee stated that IP3 and its vendor have ongoing processes which assure that the LOCA input parameters' ranges and values for IP3 LOCA analyses (conservatively) bound the ranges and values of those parameters for the as-operated IP3 plant. This assures conformance with 10 CFR 50.46.

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 IP3 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 IP3. The NRC staff concludes that the Westinghouse LOCA methodologies identified above are applicable to IP3, which is a Westinghouse-designed plant that uses Westinghouse fuel.

3.2.2.11.1.3 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 coolant pump discharge cold leg pipe, which could, under some circumstances, lead to 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 its December 15 letter, the licensee discussed information which is included in a generic Westinghouse report written to address this issue. In its February 11, 2005, letter, the licensee stated that the Emergency Operating Procedures (EOPs) at IP3 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 its December 15, 2004, letter, 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 IP3 licensing basis and does not resolve the generic issue of slot breaks at the top and side of the pipe for any vendor methodology.

3.2.2.11.1.4 Downcomer Boiling and Sustained Core Quench

In its December 15, 2004, letter, the licensee provided the results of an analysis it had performed using the approved Westinghouse best-estimate LBLOCA methodology and demonstrated that, following a LBLOCA, IP3 would attain a stable and sustained core quench. The results in the December 15 letter were calculated for only slightly over 500 seconds, but they did demonstrate that the core had been quenched at that time. In a letter dated February 3, 2005, the licensee indicated that in previous analyses for the IP2 plant, which shares the same design as IP3, quench was demonstrated out to 1600 seconds, with parameter trends similar to IP3 in the first 600 seconds. The licensee concluded that there are no differences between the two plants that would significantly affect the qualitative comparisons of these trends out to 1600 seconds. The licensee further concluded from this that at IP3 downcomer boiling would not occur to the extent that it would significantly degrade core cooling in the first 1600 seconds of a LBLOCA transient. 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 IP3, then the NRC staff will request the licensee to address these issues consistent with any generic resolution.

3.2.2.11.1.5 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 (emergency core cooling system), 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 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 vessel (RV), 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, such as 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 8. Analysis of H_3BO_3 behavior using a variation of the Reference 8 model was used for the Byron and Braidwood thermal power increase that was granted by the staff via Reference 9. A further model variation to introduce conservatisms was described in Reference 10 with staff approval via Reference 11. The staff compared the licensee's description of its model with the Reference 10 model and found no significant differences. Thus, the staff accepts the licensee's statement that "the methodology ... is consistent with, or otherwise conservative with respect to, the methodology described in" Reference 8.

The licensee provided supplemental information in its February 3, 2005, letter that addressed the earliest time when switchover to hot leg injection may be initiated. It stated that the earliest time permitted by procedures is 4 hours. Using assumptions described in the above model, it predicted a boiloff rate of 285 gpm at this time. It stated that the ECCS flow rate after realignment to hot-leg recirculation, assuming the limiting single active failure, would be 477.6 gpm for a cold-leg break, and 345.5 gpm for a hot leg break. It further stated that the available low head ECCS flow rate for the limiting single passive failure would be 751 gpm with

one line spilling. It concluded that available ECCS flow at 4 hours was more than sufficient to provide core cooling if the switchover was initiated at 4 hours. The NRC staff concurs.

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, they do not include consideration of potentially significant phenomena associated with transient or pseudo- steady state conditions, and they do not address potential behavior during SBLOCAs where natural circulation may be lost and regained, including whether H_3BO_3 may precipitate 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.[1] 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 NRC staff judged the action was necessary.

This comparison is provided in the following table which compares information from References 12 and 13 to characteristics provided by the licensee:

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[1]The licensee provided some applicable information in Reference 27 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.

In another case, the staff and a licensee evaluated RCS response in which a significant void was calculated in the reactor vessel so that the effective volume for dilution of H_3BO_3 was reduced from the typical assumption of a collapsed liquid level at the bottom of the hot leg. With this modeling, analyses established that steam flow would transport liquid out of the vessel via the hot legs through the SGs in the first hours following LOCA initiation. Further, the volume in which H_3BO_3 was concentrating would also include the two phase mixture in the hot legs and SG inlet plena that was not swept out of the RCS. These effects would reduce the H_3BO_3 concentration rate compared to the rate predicted if the two phase mixture was assumed limited to the reactor vessel. The timing predictions using this approach were found to be similar to those predicted by the historic models. Since significant conservatisms remain that are not credited in either of the approaches, the staff remains confident that more sophisticated confirmatory analyses will establish that the approach to H_3BO_3 concentration will be shown to be conservative.

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)	Indian Point 2 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
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
*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 reasonably 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 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.

3.2.2.11.2 Non-LOCA Transients and Accidents

The licensee reanalyzed IP3's FSAR Chapter 14 non-LOCA events at the SPU conditions. The NRC previously approved the computer codes and methodologies used in each of the non-LOCA transient analyses at IP3. The licensee used the RETRAN-02 (RETRAN) computer code in the IP3 non-LOCA SPU safety analyses, simulating a Westinghouse 4-loop plant design, applicable to IP3, as described and presented in WCAP-14882-P-A (Reference 14). 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 15, 16, and 5, 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 uncontrolled RCCA withdrawal from a subcritical or low power startup condition analyses (References 17 and 18). The licensee met the conditions and restrictions set on the specific codes. Where applicable, the licensee used the previously approved RTDP methodology discussed in WCAP-11397-P-A (Reference 19) in performing the non-LOCA safety analyses. The NRC staff determines that the codes and methodologies used by the licensee to perform the safety analyses under SPU conditions are acceptable since the licensee satisfies the conditions and restrictions set on the specific codes for application at IP3.

3.2.2.11.2.1 Uncontrolled RCCA Withdrawal From a 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 departure from 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 with a nominal temperature of 547 EF and used the most positive moderator temperature coefficient (MTC) since this yields the maximum rate of power increase, based on the total reactor trip reactivity on the assumption that the highest control rod assembly was stuck in its fully withdrawn position. The analysis also used a conservatively low doppler power reactivity coefficient value. The licensee used the same method as in the analysis of record (AOR), the RTDP, 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 6.3-18 of the application report.

Based on its review, the NRC staff finds that the licensee's analysis was performed using acceptable analytical models, and the results of the analysis demonstrated that the DNBR safety analysis limit will not be exceeded and the peak fuel centerline temperature will remain below the safety analysis limit, thereby satisfying the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical condition.

3.2.2.11.2.2 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 Main Steam System (MSS) being maintained below 110 percent 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, the highest worth RCCA was stuck in its fully withdrawn position, and the maximum positive reactivity insertion rate was greater than that which would be obtained from the 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 IP3 at SPU conditions. The peak RCS pressure and peak MSS pressure remained below the 110 percent of the design pressures, as provided in Table 6.3-18 of the application report.

Based on its review, the NRC staff finds that the licensee's analysis was performed using acceptable analytical models, and the results of the analysis demonstrated that the DNBR safety analysis limit will not be exceeded and the RCS and MSS peak pressures will be maintained below the 110 percent design values, thus satisfying the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the uncontrolled RCCA withdrawal at power.

3.2.2.11.2.3 Rod Cluster Control Assembly Drop/Misoperation

RCCA misoperation accidents include dropping one or more RCCAs within the same group, a dropped RCCA bank, or a statically misaligned RCCA. 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 at beginning of life and end of life, and a range of 0 to -35 pcm/EF MTCs which bounded the limiting time in life. The generic transient analysis statepoints used for IP3 are based on generic dropped rod analyses confirmed to be applicable to IP3, specifically performed to support elimination of a turbine runback on a dropped rod event. Additionally, no credit for any direct trip due to the dropped rod was taken in the generic analysis. 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 20). In its response to a staff RAI, the licensee provided the data which showed that 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. 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.

Based on its review, the NRC staff found that the licensee's analyses were performed using acceptable analytical models and the results of the analyses demonstrated that the minimum departure from 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, thus satisfying the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed stretch power uprate is acceptable with respect to the RCCA drop/misalignment transients.

3.2.2.11.2.4 Chemical and Volume Control System Malfunction

Unborated water can be added to the reactor coolant system, via the chemical and volume control system (CVCS). The CVCS system 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 is based on the minimum DNBR remaining above the safety analysis limit, pressure in the RCS and MSS being maintained below 110 percent 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 reanalyzed 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. The analysis was performed at refueling, startup and power modes. For operation at power and during startup, one or more RCPs are in service at IP3 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. Prior to entering the refueling mode, plant procedures require isolation and documentation of paths that could cause dilution. During refueling, at least one RHR pump is in service and the flow rate is considered adequate for mixing in the lower plenum. The minimum times required in order to credit operator action for this event are at least 15 minutes during full power operation and startup, and at least 30 minutes during refueling. 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 and at full operation met the acceptance criteria set forth in the SRP. Therefore, no violation of the DNBR safety analysis limit, increase to 110 percent of RCS or MSS design pressures, or exceeding fuel temperature and clad strain limits occurred.

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

3.2.2.11.2.5 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, become 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 percent of the design values. Specific review criteria are contained in SRP, Section 15.2.1-5.

The licensee reanalyzed 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 (beginning of life) 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 auxiliary feedwater (AFW), except for long-term recovery to mitigate the consequences of the transient. The licensee used the 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 results of the analysis confirmed that the pressurizer water-solid condition was precluded, thus uncompromising the RCS pressure boundary and preventing progression into another condition event. The results also showed the primary system pressure remained below the 110 percent design value and the secondary side steam pressure below 110 percent of the SG shell design pressure. To be conservative, the minimum DNBR with pressure control case took credit for the pressurizer spray and pressurizer PORVs, but not the steam dump since these conditions increase the possibility that DNB will occur. With the reactor tripped on an OTΔT reactor trip signal, the analysis results showed that the minimum DNBR remained above its safety analysis limit.

Based on its review of licensee's analysis of the loss of external electric load, the NRC staff found that the licensee's analysis was performed using acceptable analytical models, and the results of the analysis demonstrated that the minimum DNBR will remain above the safety analysis limit and pressure in the RCS and MSS will remain below 110 percent of the design values for the proposed power uprate, thus meeting the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the loss of external electric load.

3.2.2.11.2.6 Loss of Normal Feedwater

Loss of normal feedwater (LONF) flow could occur from pump failures, valve malfunctions, or a loss 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 event. 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 percent 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, power operated relief valves (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 pump start of the two motor-driven auxiliary feedwater pumps (MDAFWPs) and the turbine-driven auxiliary feedwater pump (TDAFWP) was assumed to be initiated 60 seconds following a low-low SG water level signal. The analysis of record used a delay time of 70 seconds. The licensee changed the time to 60 seconds as part of the SPU. The NRC staff finds this acceptable since this is a conservative action by which the pump will have to be declared inoperable if it does not meet this more stringent time requirement.

The worst-case 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 343 gpm, distributed equally between two of the four 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 TDAFWP is completely independent of the MDAFWPs and there are redundant power supplies to the MDAFWPs. The three AFWPs can be started remotely manually in the control room or locally at the pump room. The LONF event was reanalyzed at the SPU conditions using the RETRAN computer code. In this amendment 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 its November 18, 2004, letter, the licensee indicated that the additional AFW flow is equivalent to the flow from the other MDAFW pump (the TDAFW pump 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 26). The licensee also confirmed the IP3 SPU analyses demonstrated that the AFW system provides sufficient flow to prevent the specified fuel design limits from being exceeded or a system overpressurization from occurring.

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 percent design pressures throughout the transient with a 10-minute delay time. 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 indicated that 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 that 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 NRC 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 percent of the design pressures, and a more serious plant condition is precluded, thereby, meeting the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed SPU is acceptable with respect to the loss of normal feedwater flow event.

3.2.2.11.2.7 Loss of AC Power to the Plant Auxiliaries

The loss of non-emergency ac power is assumed to result 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 percent 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 used the RETRAN code to determine the plant transient following a loss of ac power. In performing its analysis, the licensee assumed the worst single failure was the loss of one of the two MDAFWPs. There is also a 60-second delay time as modeled in the LONF and the reactor trips on SG low-low water level. The staff reviewed the additional assumptions for this transient to confirm they were consistent with the assumptions modeled in the LONF. From its analysis, the licensee concluded in a loss of ac (LOAC) power to the station auxiliaries, the plant response is almost identical to the complete loss-of-flow accident in which the pump coastdown inertia along with reactor trip prevents reaching the DNBR limit. After the trip, the AFW system removes decay heat and this portion of the transient is similar to the LONF event. The licensee also proposed to credit operator action within 10 minutes of the trip to start the second MDAFWP or align the TDAFWP. The staff finds it acceptable to take credit for operator action in the LOAC event since the latter part of this transient is similar to 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 in Reference 26 that with respect to DNB, 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.

Based on its review of the licensee's analysis of the loss of ac power to plant auxiliaries, the NRC staff found that the licensee's analysis was performed using an acceptable analytical model, and the analysis results 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, thereby meeting the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the loss of ac power to the plant auxiliaries.

3.2.2.11.2.8 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 MSS being maintained below the 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Specific review criteria are contained in SRP Section 15.1.1-4.

In performing its analysis, the licensee used the RETRAN computer code to calculate temperatures, pressures, and power level, and the RTDP methodology with the VIPRE subchannel code to calculate the hot channel heat flux transient and DNBR. The excessive feedwater flow full power cause was analyzed with automatic rod control and manual rod control. A hot-zero-power condition case was also ran for this event. The RPS provided mitigation for this event and the results showed RCS pressure remained below the 110 percent design value. The limiting case DNBR value remained above the safety analysis limit provided in Table 6.3-18 of the application report.

The NRC staff has reviewed the licensee's analysis and found that the licensee's analysis was performed using acceptable analytical models, and analysis results demonstrated that the reactor protection and safety systems will continue to ensure the 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, thereby satisfying the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

3.2.2.11.2.9 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-percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent 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 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt.

The licensee evaluated four cases which demonstrated that the fuel cladding integrity will not be adversely affected following a 10-percent step-load increase from rated load. One case was a manually controlled reactor with beginning of life (BOL) reactivity feedback. The second case was a manually controlled reactor with end of life (EOL) reactivity feedback. The third case was an automatically controlled reactor with BOL reactivity feedback and lastly, an automatically controlled reactor with 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 IP3 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 that were used in the evaluation of this transient were provided in Reference 26. The statepoints generated were compared to the IP3 SPU limiting DNB core limit lines that represent the limiting DNBR conditions for the uprate. The licensee showed 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.

Based on its review of the licensee's analysis of the excessive load increase incident, the NRC staff found that the licensee's analysis demonstrated the SPU DNBR safety analysis limit remains bounding for this event. The NRC 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 percent of the design pressures, and the peak linear heat generation rate will not exceed a value that would cause fuel centerline melt, thus meeting the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the excessive load increase incident.

3.2.2.11.2.10 Steam Line Break

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 ANS condition IV event, fuel failure is expected, but the radiological consequences should meet the dose guidelines specified in SRP Section 15.1.5.

In performing its analysis, the licensee assumed EOL SDM at no load, equilibrium xenon conditions and the most reactive RCCA stuck in its fully withdrawn position. The licensee assumed two conditions which cause an underprediction of the reactivity feedback in the high power region near the stuck rod. These two conditions were the negative moderator coefficient corresponding to an EOL rodded core with the most reactive rod withdrawn and core power distribution was uniform. 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 modeled a conservative minimum SI flow resulting from the failure of one HHSI train or a cold leg branch line motor-operated valve in the analysis of the HHSI system. 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 has reviewed the licensee's analysis of the excessive heat removal due to steam line break and found that the licensee's analysis was performed using acceptable analytical models, and the results of the analysis demonstrated compliance with the DNB design basis criterion, meeting the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the steam line break.

3.2.2.11.2.11 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 percent of the design pressures. Specific review criteria are contained in SRP Sections 15.3.1 and 15.3.2.

The licensee reanalyzed 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 14 and 15. 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 of SRP 15.3.1/2 for these events were satisfied.

The NRC staff has reviewed the licensee's analyses of the loss of reactor coolant flow and found that the licensee's analyses were performed using acceptable analytical models, and results 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 percent of the design pressures, thereby meeting the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the loss of reactor coolant flow.

3.2.2.11.2.12 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 reanalyzed 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 results showed that the DNBR value remained above the safety analysis limit, ensuring no fuel rods experienced DNB. The assumption of 5 percent of the fuel rods in the core suffered damage used in the radiological dose analyses for this is conservative when it is compared with the DNBR calculation results.

The NRC staff has reviewed the licensee's analyses of the locked rotor and pump shaft break events and found that the licensee's analyses were performed using acceptable analytical models, the results of the analysis demonstrated no fuel rod experienced DNB, thus satisfying the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the locked rotor accident.

3.2.2.11.2.13 Rupture of a Control Rod Drive Mechanism 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 to determine 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 (ASME) Boiler and Pressure Vessel Code.

The licensee performed the rod ejection accident analysis with the methods documented in Westinghouse Topical Report WCAP-7588, Revision 1-A (Reference 21). The licensee addressed applicability of this report in letter NL-04-145, and the staff finds it acceptable since the licensee met the conditions set forth in the SE approving use of WCAP-7588. The maximum fuel pellet enthalpy at the hot spot calculated for each rod ejection case was less

than 200 cal/gm. The licensee analyzed two sest of cases for the accident, one initiated from full power and one initiated from zero power. The analysis of both these cases used both BOL and EOL kinetics. Table 5.3-15 in the June 3 application report lists the values of the initial plant parameters (such as initial power level, ejected rod worth, delayed neutron fraction). The licensee used the TWINKLE computer code to perform its average core transient analysis and the FACTRAN code to perform the hot region analysis. The results submitted by the licensee for the rod ejection analysis showed that 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.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident, such as a rod ejection event, at lower enthalpies than the guidelines currently specified in Regulatory Guide (RG) 1.77, “Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors.” However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during reactivity insertion accidents will be much lower than the RG 1.77 guidelines, based on their 3D neutronics calculations. For high burnup fuel which has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much lower than 100 cal/gm.

The NRC staff has reviewed the licensee’s analysis of the rod ejection accident and found that the licensee’s analysis was performed using acceptable analytical models, and the analysis results 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, thereby meeting the regulatory requirements following implementation of the proposed SPU. Therefore, the NRC staff concludes that the proposed power uprate is acceptable with respect to the rod ejection accident.

3.2.2.11.2.14 Steam Generator Tube Rupture

A SG 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 Part 100. The 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 Part 100 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 22). Following a 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. Operators are currently required to terminate break flow within 60 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 has reviewed the licensee's analysis of the SGTR accident and determined that the licensee's analysis adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods, 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 concludes that the proposed SPU is acceptable with respect to the SGTR.

3.2.2.11.2.15 Anticipated Transients Without Scram

Anticipated transients without scram (ATWS) is defined as an anticipated operational occurrence followed by the failure of the RPS specified in GDC-20. Section 50.62 of 10 CFR Part 50 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 AFW 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 (such as IP3) where a DSS is not specifically required by 10 CFR 50.62, the 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 moderator temperature coefficient (MTC) and the primary system relief capacity.

The licensee reanalyzed the two most limiting RCS overpressure transients at SPU conditions to ensure the basis for the final ATWS Rule continues to be met. The two most limiting transients at IP3 are the Loss of Load (LOL) and the LONF. The results of the LOL and LONF ATWS analyses performed showed the peak pressures are less limiting than the corresponding peak pressures obtained for the cases in the ATWS analyses for four-loop Model 44 SGs (Reference 23). The IP3 TS indicate the MTC upper limit shall be less than 0 pcm/EF at all power levels. The licensee is maintaining this limit in the proposed SPU. In its November 18, 2004, letter, 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 an 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 indicated that the MTC upper 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's acceptable analysis demonstrated that the peak primary system pressures following an ATWS event for the LOL and LONF will remain below the acceptance limits. 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 SPU.

3.2.2.11.2.16 Station Blackout

Station blackout (SBO) refers to a complete loss of ac power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the loss of offsite power concurrent with a turbine trip and failure of the onsite emergency ac power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from "alternate AC sources" (AACs). The NRC staff's review focuses on the impact of the proposed SPU 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's acceptance criteria for SBO are based on 10 CFR 50.63, which provides the requirements for plants to withstand an SBO of specified duration and recover. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2.

The licensee provided the results of its evaluation relative to the SPU affecting the plant coping capability in an SBO. The SBO minimum required coping duration for IP3 is determined to be 8 hours. For the SPU, the licensee determined the volume of water required for 8 hours of decay heat removal and primary system cooldown to 320 EF was nominally 148,000 gallons. TS 3.7.6 requires that a minimum of 360,000 gallons of water must be available in the Condensate Storage Tank during plant operation above 350 EF. The licensee also determined in its evaluation of plant fluid systems affected by SPU conditions that there are no new SBO loads that require 125 VDC control or motive power, and that there is no need to modify existing SBO loads that require 125 VDC control or motive power. The licensee evaluated the air operated valves used for mitigating an SBO and found there was no effect due to the uprate. The licensee also evaluated containment isolation and reactor coolant inventory and found them to meet the acceptance criteria. The current SBO analyses identified the AFW pump room as the only area of concern in the case ventilation is lost. Since the temperatures used in the SBO analyses envelop the SPU conditions, the AFW pump room analysis is not affected by the SPU.

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

3.2.2.11.2.17 Criticality Accident Requirements

Section 50.68(b) of 10 CFR Part 50 lists requirements the licensee shall comply with in lieu of maintaining a monitoring system capable of detecting a criticality as described in 10 CFR 70.24.

In a letter dated April 15, 1997 (Reference 24), the SE for amendment No.173 to the IP3 license addressed an increase in the uranium-235 (U-235) enrichment of fuel stored in the fresh fuel storage racks or the spent fuel storage racks from 4.5 weight percent to 5.0 weight percent U-235. In this amendment, the staff determined that the criticality aspects of the proposed increase in the fuel enrichment limit of the IP3 fresh and spent fuel pool storage racks to be acceptable. The licensee evaluated its criticality analysis and current TSs against the criteria set forth in 10 CFR 50.68(b) and determined it was in compliance with the regulatory requirements. The NRC staff reviewed the SE referenced, the RAI response, and current TSs and confirmed the licensee's evaluation is correct. Therefore, the NRC staff agrees that the licensee is in compliance with 10 CFR 50.68(b).

3.2.3 Summary

The NRC staff reviewed the licensee's evaluations, analyses and proposed TS changes to support operation of IP3 at the proposed stretch power uprate level of 3216 MWt. Additionally, the staff reviewed the use of methodologies not previously approved for use at IP3. Based on its review, the staff finds that the supporting safety analyses were performed with NRC-approved computer codes and methods; their implementation at IP3 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 IP3.

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 and 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 a 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 remain qualified and were 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. 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 turbine drive of the AFW pump in the AFW pump room
- The SG blow-down line break in the pipe penetration area

The equipment that is required to respond to these HELBs has been re-evaluated 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 licensee re-evaluated the SPU effect on radiation outside the containment. 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 SPU 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 the loss of the nuclear 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, which provides requirements for onsite and offsite electric power systems. 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 application report, the main generator is rated at 1125.6 Megavolts-ampere (MVA) when operated from 0.9 lagging power factor (pf) up to and including unity pf at 75 psig hydrogen pressure. The main generator provides power through the isolated phase bus at 22 kV to both the main transformer and the unit auxiliary transformer. 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 ac power also provides a source of offsite ac power to all emergency loads necessary for the safe shutdown of the reactor. The conformance of the electrical distribution system to GDC 17 was described in FSAR Sections 1.3 and 8.2 and the evaluation does not change due to SPU conditions .

3.3.2.2.1 Grid Stability

The licensee analyzed the grid stability by using the stability data provided by the New York Independent System Operator (NY-ISO). No changes to the offsite power system are required as a result of the proposed SPU. The thermal analysis shows no adverse impact on the transmission interfaces to IP3 during increased plant output at SPU. The contingency analysis shows no change in voltage behavior at SPU based on the loss of the most critical transmission line or the largest generator on the grid. The reactive capability of the main generator meets the normal power requirement of 225 MVAR lagging and 100 MVAR leading, and the IP3 reactive power commitments. By letter dated December 15, 2004, the licensee provided additional information in response to staff concerns. Regarding the MVAR support necessary to maintain post-trip loads and minimum voltage levels, the licensee stated that IP3 is not required to maintain any specific MVAR loading during normal operation. IP3 was evaluated by the NYISO for the previous 1.4% uprating at 225 MVAR lagging and 170 MVAR leading. The licensee further stated that, after the power uprate, there would be no change in nature and quantity of MVAR support necessary to maintain post-trip loads and minimum voltage levels. The reactive power support would be 225 MVAR lagging and 100 MVAR leading. The decrease in leading reactive support was determined to have little or no impact on system voltage control. Therefore, for IP3 no action was required to mitigate the reduction in leading reactive capability.

Regarding any compensatory measures to adjust for any shortfalls in reactive support, the licensee stated that the NYISO approved the evaluation of the uprating (225 MVAR lagging and 100 MVAR leading) without requiring any compensatory measures. IP3 is connected to the Con Edison electrical transmission system that is operated under the rules of the NYISO. The NYISO and the interconnecting transmission owner have reviewed and approved the MVAR capability of IP3 at SPU conditions. Once the maximum MVAR capability of the units connected to the system has been reached, the NYISO has the authority to order a reduction in

generator MWe output to achieve the needed MVAR support. IP3 is obligated to respond to such a request. Any need for additional MVAR support on a grid-wide basis would be identified and addressed by the NYISO as part of their annual system reliability studies. All large generators within the NYISO control area are required to perform an annual reactive capability test. The results of the test determine the annual reactive compensation payment to the generator. Historically the MVAR values achieved during this testing have been lower than the unit's design capability because the generator exciter voltage, and/or grid voltage limits are reached prior to any generator capability limits. At the uprate MWe output, IP3's reactive capabilities are still within the generator and main transformers capability/rating. NYISO approval of the IP3 SPU (at 225 MVAR lagging and 100 MVAR leading) did not require any compensatory measures.

The NRC staff requested that the licensee evaluate the impact of any MVAR shortfall on the ability of the offsite power system to maintain minimum post-trip voltage levels and to supply power to safety buses during peak electrical demand periods. The licensee responded by stating that there is no MVAR "shortfall." The evaluation performed by and for the NYISO was an extensive system reliability impact study in accordance with the NYISO rules.

The NRC staff reviewed the licensee's submittal and concluded that there are no changes to the offsite power system as a result of the proposed IP3 SPU. Contingency analysis shows almost no change in voltages at SPU based on the loss of the most critical transmission line or the largest unit on the grid. The availability of stable offsite power to IP3 is assured and the design is, therefore, acceptable.

3.3.2.2.2 Main Generator

The main generator is rated at 1125.6 MVA when operated from 0.9 lagging pf up to and including unity pf at 75 psig hydrogen pressure. The capability has been evaluated in order to accommodate an output of 1093.5 MWe at SPU. The main generator gross real power output at the reactor thermal power level of 3244 MWt is 1093.5 MWe. IP3 reactive power commitments credited for this SPU are 225 MVAR lagging and 100 MVAR leading. The generator capability curve shows that the machine is capable of continuous operation at an output of 1013 MW at 0.9 lagging pf up to and including 1125.6 MW at unity pf at 75 psig hydrogen pressure and the main generator is adequate to support the unit operation at SPU condition of 1093.5 MW.

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

3.3.2.2.3 Main Power Transformer (MT)

The main generator delivers its power output to two MTs. The name plate rating of each MT 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 unit auxiliary transformer when the unit is operating at full power. The maximum calculated load for the MT is 1053 MVA which is below the maximum rating of 1214 MVA. Therefore, the MT is adequately sized to support unit operation at SPU conditions.

The NRC staff reviewed the licensee's submittal and concluded that the MT will continue to operate at the SPU conditions and the design is, therefore acceptable.

3.3.2.2.4 Isolated Phase Bus

The isolated phase bus duct connects the main generator to the primary windings of the MTs and the Unit Auxiliary Transformer (UAT). The isolated phase bus system is organized into 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 continuous current rating of the 1.5 kA portion of the IPB tap bus exceeds the anticipated worst-case bus loading of 1.328 kA at SPU with substantial margin and the design of the 1.5 kA bus is therefore, acceptable. 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. For Phase 1 SPU (1080 MWe, 225 MVAR lagging and 100 MVAR leading), the isolated phase bus is capable of operating within its ratings. The Phase 2 SPU increases the main generator's electrical output to 1093.5 MWe, 225 MVAR lagging and 100 MVAR leading but the isolated phase bus duct will operate slightly outside its ratings. The anticipated worst-case loading at SPU exceeds the continuous current rating of the isolated phase main bus. In a letter dated December 15, 2004, the licensee stated that the Phase 1 power level of 1080 MWe is not expected to require any modifications to the iso-phase bus duct cooling system. At the Phase 2 power level, the generator output is calculated to reach a maximum 1093.5 MWe (including a 0.5% margin in the heat balance). The Phase 2 power level may require modifications for the iso-phase bus duct cooling system. The extent of this modification could include (worst case) the new higher capacity cooling coils, new higher capacity fans with associated dampers and removal of the first filter rack to reduce pressure loss and to increase air flow.

The NRC staff reviewed the licensee's submittal and concluded that the isolated phase bus main duct will continue to operate at the anticipated power uprate after upgrading the existing main isolated phase bus duct coolers and the design is, therefore, acceptable. Prior to upgrading, the licensee stated that it would control the maximum reactive power limits.

3.3.2.2.5 Station Auxiliary Transformer (SAT)

The SAT nameplate rating is 43 MVA FOA @ 55 EC rise, and 48.16 MVA FOA at 65 EC rise. The licensee reviewed the original load flow analysis and the analysis showed that the highest postulated load on the SAT is during a steam break accident with phase B isolation and buses 2A and/or 3A not available. During this event, the total secondary load of the SAT at SPU is calculated to be 49.295 MVA which is less than the existing load of 49.309 MVA. However, there is conservatism in the load flow analysis. Buses 5 and 6 alone include a total of about 2.5 MVA of excess load. Therefore, the existing load of the SAT during peak accident conditions would be decreased to 46.809 MVA and the new SAT load at SPU would be decreased to 46.796 MVA. In both cases, the total SAT load is less than the SAT rating of 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 based on the analyzed normal and accident loading conditions and the design is, therefore, acceptable.

3.3.2.2.6 Unit Auxiliary Transformer

The UAT nameplate rating is 22/6.9 kV, 43 MVA FOA @ 55 EC rise, and 48.16 MVA FOA at 65 EC rise. The licensee reviewed the original load flow analysis and the analysis showed that the worst-case loading occurs during normal operation at full load. The worst-case total secondary load on the UAT is 44.563 MVA which is less than the UAT maximum name plate rating of 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 based on the analyzed normal and accident loading conditions and the design is, therefore, 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 modification to the main isophase bus duct. 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 onsite ac 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 Sections 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 a load decrease on EDG 32 from 1984.8 to 1981.6 kW. The loading on the EDGs resulting from SPU is bounded by the existing EDGs. 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 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 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 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

3.3.5.1 Regulatory Evaluation

Station Blackout refers to the complete loss of ac electric power to the essential and nonessential switchgear busses in a nuclear power plant. An 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 recovery from an SBO event for SBOs are based on 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

The SBO Rule, 10 CFR 50.63, 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), NUMARC 87-00. The Appendix R diesel generator serves as the AAC source. The AAC power source will be available within 1 hour of the onset of the SBO event. The SBO minimum required coping duration for IP3 was determined to be 8 hours. The 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 Nuclear Management and Resources Council (NUMARC, now called Nuclear Energy Institute) Report 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 292,200 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 EF. 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 IP3 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 TDAFW pump, which operates during an SBO can be operated manually and the speed control valve has nitrogen backup. The atmospheric relief valves have two backup nitrogen supplies. The licensee evaluated and determined that the systems are not affected under SPU conditions.

3.3.5.2.4 Effects of Loss of Ventilation

The existing plant SBO analyses identified the AFW pump room as the only area of concern in accordance with the criteria of NUMARC 87-00. The temperatures used in the analysis of AFW pump room temperatures after an SBO envelop the steam conditions used as the inputs for the

SPU analyses. The SPU does not affect the inputs used in the analysis of control room temperatures following an SBO.

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 identified a total of 19 containment isolation valves and all of these valves can be operated independent of the EDGs and have some means of valve position indication independent of the emergency ac power system. 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 an SBO event for the period of time established on 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 systems and environmental qualification of the electrical component. Results of these evaluations show that following implementation of the proposed modification to the main isophase bus duct coolers, the design will be acceptable for the stretched power uprate conditions. After the modification, 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

The technical evaluation included 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, USA Standard B31.1 Power Piping Code, and GDC 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 Part 50, 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 SRP Section 3.9. The review also includes the plant specific provisions relating to GL 89-10 and GL 96-05, as they pertain to programs for motor-operated valves, GL 95-07, as it pertains 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 IP3 power uprate application, as it relates to the effects of the power uprate on the structural and pressure boundary integrity of the NSSS and balance-of-plant (BOP) systems. Affected components in these systems include piping, in-line equipment and pipe supports, the reactor pressure vessel (RPV), core support structures (CSS), reactor vessel internals (RVI), SG, control rod drive mechanisms (CRDM), reactor coolant pumps (RCP) and pressurizer.

3.4.2.1 Reactor Vessel

The proposed power uprate will increase the core power by approximately 4.85 percent above the currently authorized power level of 3067.4 MWt. The licensee reported that power increase will result in changing the design parameters given in Table 2.1-2 of the June 3, 2004, application report.

The licensee evaluated the RPV 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 reactor vessel was performed in accordance with the ASME Code, Section III, 1965 Edition through Winter 1965 Addenda. Table 5.1-1 provides the calculated maximum range of primary plus secondary

stresses intensity and CUFs for the reactor vessel critical locations. The results indicate that the maximum range of primary plus secondary stresses for all the reactor vessel critical locations are within the code allowable limits of $3S_m$. 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 the ASME Code, Section III using the ASME 1968 Edition with Winter 1970 Addenda.

The licensee evaluated these critical reactor internal components considering the revised design conditions provided in Table 2.1-2 of the application report for IP3 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 application report, 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 flow-induced vibration (FIV) calculation are within the allowable limits for the proposed uprate condition since the vibrational response of the reactor internals is very small and that adequate margins of safety exist to accommodate the slight change in operating condition for the stretch power uprate with regard to FIV.

Based on the above evaluations, the NRC staff agrees with the licensee's conclusion that the reactor internal components at IP3 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. IP3 has Westinghouse full-length L-106 CRDMs. The licensee evaluated the adequacy of the CRDMs by reviewing the IP3 analysis of record against the revised conditions of Table 2.1-2, of the application report. The comparison shows that the IP3 design basis analysis remains bounding for the 4.85 percent power uprate. For instance, the RCS temperature and pressure values were compared to the current design analysis for the CRDMs. There are no changes from the current reactor coolant pressure of 2250 psia for any of the uprating cases from the SPU parameters for IP3. The hot leg temperature (T_{hot}) defined by the vessel outlet temperature on the parameters for the IP3 SPU is a maximum of 603.0 EF, which is less than the 650.0 EF temperature used in the analysis of record. 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. Table 5.3-2 and 5.3-3 of the application report 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 the CRDMs continues to be in compliance with licensing basis codes and standards for the proposed power uprate.

3.4.2.4 Steam Generators (SGs)

The licensee reviewed the existing structural and fatigue analyses of the SGs at IP3 and compared the power uprate conditions with the design parameters of the analysis of record for the Model 44F at IP3. 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 IP3.

The calculated maximum stresses and cumulative fatigue usage factors for the critical SG components are provided in Table 5.6-2 of the application report. 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 most of the maximum calculated stresses for the critical components are below the Code-allowable limits. For those primary plus secondary stress intensities exceeding $3S_m$, the licensee performed simplified plastic elastic (for divider plate and tube sheet & shell junction) or plastic analysis (for supporting ring and insert) to determine that maximum stresses in these SG components were in accordance with the Code. The results provided in Table 5.6-2 show that calculated CUFs are within the allowable limit of 1.0 for all the critical components.

In addition, the licensee evaluated the flow induced vibration of the U-bend tubes for the Model 44F SGs at IP3. 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 (RCPs)

The licensee reviewed the existing design basis analyses of the IP3 RCPs to determine the impact of the revised design conditions in Table 2.1-2 of the application report. The licensee indicated that the evaluation was performed in accordance with the requirements of the ASME Code, Section III, 1965 Edition, which is the Code of record.

After the 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 application report 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 IP3 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 4.85 percent power increase from the current rated power, will remain in compliance with the requirements of the codes and standards under which IP3 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 IP3 pressurizer.

The key parameters in the current IP3 pressurizer stress report were compared against the revised design conditions in Table 2.1-2 for the proposed stretch 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 of the application report. 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 IP3 involves the increase of temperature difference across the RCS. The licensee evaluated the NSSS piping and supports by reviewing the design-basis analysis of WCAP-8228, Revision 1, against the uprate power design system parameters shown in Table 2.1-2, 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, 1967 Edition was used for the power uprate evaluation of IP3 RCS piping except the surge line which was evaluated in accordance with requirements of the ASME Code, Section III, Subsection NB, 1986 Edition, which is the Code of record. The calculated stresses are provided in Tables 5.4-1, 5.4-2, and 5.4-3 of the application report for the primary loop piping

for the power uprate. The maximum calculated stresses are shown to be 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 IP3 power uprate. The proposed power uprate does not change the maximum RCS pressure. The DBLOCA forces due to postulated primary loop guillotine breaks have been eliminated using the loop leak-before-break (LBB) methodology for IP3. 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 in the hot leg, the 10-inch accumulator line nozzle in the cold leg, and the 14-inch residual heat removal (RHR) line nozzle in the hot leg. As such, the DBLOCA 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 IP3.

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 IP3 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, and the heater vents and drains piping. 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 2.1-1 for up to 3216 MWt. In its November 18, 2004, response (Reference 25) to the staff's RAI, Tables 1 to 5 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 IP3.

The licensee also reviewed the programs, components, structures, and generic letter issues as they pertain to the power uprate. As discussed in the June 3, 2004, application and in its responses dated November 18 and December 15, 2004, to NRC questions, the licensee evaluated the effect of the requested SPU on the functionality of safety-related pumps and valves at IP3. In considering the licensee's power uprate request, the NRC staff reviewed the licensee's submittals that included examples of its component evaluations. For example, the licensee determined that the SPU had no or negligible impact on system operating pressures

and flow rates, or pump performance, for the RCS, CVCS, primary sampling system, RHR system, CCW system, recirculation system, and CSS. The licensee evaluated the remaining plant systems and did not identify any significant changes in performance requirements. The licensee evaluated the potential effect of the power uprate on valves in the motor-operated, air-operated, and hydraulic-operated valve programs at IP3. The licensee previously evaluated safety-related MOVs in response to GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." In a letter dated February 12, 1998, the NRC informed the licensee that it had completed the detailed review of the GL 89-10 program at IP3 through plant inspections and review of licensee submittals. In a letter dated May 11, 2000, the NRC accepted the licensee's MOV program in response to GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves," through review of submitted information. In evaluating the potential impact of the power uprate at IP3, the licensee determined that the small changes in system flows, pressures, and temperatures resulting from the SPU will not adversely affect MOV performance. In addition, the accident peak ambient temperatures that might result from power uprate operation are bounded by the accident peak ambient temperatures for the pre-uprate conditions such that the SPU will not affect the results for the current evaluations of motor output for MOV performance. Further, no adverse effects were identified regarding safety and relief valves in light of the minimal changes in performance requirements. The licensee also evaluated the potential 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 reevaluated the safety-related power-operated gate valves for the potential affects of SPU conditions on potential pressure locking and thermal binding. The licensee determined that the modifications and analyses previously performed remain valid for the SPU conditions in light of minimal changes in performance requirements and ambient temperature conditions for the power-operated gate valves at IP3. 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 IP3 to be acceptable, based on the staff's previous review of the licensee's programs in response to GLs 89-10, 95-07, and 96-05; and the current review of the information submitted by the licensee describing the scope, extent, and results of the evaluation of safety-related pumps and valves.

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." GL96-06 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. The licensee indicated that the maximum temperature utilized for structural evaluation in response to GL 96-06 pertaining to the over-pressurization of pipe segment envelops the peak containment temperature for a LOCA under SPU conditions. Therefore, the current GL 96-06 evaluation remains unchanged for the SPU operation at IP3. On the basis of the above review, the 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 89-10, GL 95-07, GL 96-05 and GL 96-06, 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 4.85 proposed power uprate.

3.4.3 Summary

On the basis of its review, 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, including conformance with the intent of GDC 1, 2, 4, 10, and 15, and therefore, concludes the foregoing components to be acceptable for IP3 uprate operations at the proposed core power level of 3216 MWt.

3.5 Radiological Consequences Evaluation (Doses)

The licensee reanalyzed a number of design-basis accidents (DBAs) to support the SPU. The reanalysis implemented the alternative source term (AST) methodology for this SPU. Use of the AST methodology requires the NRC-staff approval under 10 CFR 50.67. The licensee requested approval of this methodology in a separate submittal dated June 2, 2004. The NRC staff reviewed the consequences of the accidents which retained the AST methodology under a separate licensing action. The acceptability of the implementation of this methodology and the SPU with regard to the consequences from these accidents are addressed in the NRC staff's SE dated March 22, 2005, for the AST amendment (ADAMS No. ML050750431).

Three of the accidents which were reanalyzed for the SPU, and which utilized the AST methodology, were the rupture of the volume control tank and a waste gas decay tank and the failure of a holdup tank. In response to an RAI, on November 18, 2004, the licensee submitted a letter to the staff that indicated its intent to retain the whole body and thyroid dose criteria for these accidents in lieu of the total effective dose equivalent (TEDE) criteria of 10 CFR 50.67. In support of the SPU and this change in approach, the licensee provided whole body and thyroid and beta skin doses for individuals located at the exclusion area boundary (EAB), low population zone (LPZ) and in the control room.

The NRC staff noted that in the November 18 letter, the licensee had stated that the thyroid dose equivalent to 500 mrem to the whole body is 16.7 rem thyroid and that this equivalency is based upon an organ dose-weighting factor of 0.03. This is incorrect and unacceptable. For these accidents, the acceptance criterion was the offsite limit for 10 CFR Part 20, 500 mrem whole body. The organ dose-weighting factor is a methodology associated with the use of TEDE. It is not in effect when doses are expressed in terms of thyroid and whole body. Thus, the thyroid limit for the EAB and LPZ would not be 16.7 rem, rather, the limit would be 1.5 rem. The basis for this limit can be found in Section 5.2.1 of NUREG-0133, "Preparation of Radiological Effluent Technical Specifications for Nuclear Power Plants." The NRC staff notes the licensees calculations indicate the consequences of these three accidents are within this limit.

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 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, which 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, through the 1982 edition." ASTM Standard Practice E185 (ASTM 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 RV material predicted transition temperature shifts (ΔRT_{NDT}). The surveillance capsule withdrawal schedule is prepared in terms of effective full-power years (EFPY) of plant operation with a projected design life of 32 EFPY. Entergy is applying the 1982 Version of ASTM E185 (ASTM E185-82) as its basis for implementing the IP3 RV materials surveillance program.

The licensee discussed the impact of the 4.85 percent SPU on the RV material surveillance program in Section 5.1.2.1 of the application report and stated that the revised SPU fluence projections have been used in the assessment of the current withdrawal schedule for IP3. This calculation determined that the maximum ΔRT_{NDT} using the SPU fluences corresponding to 3216 MWt for IP3 at 27.1 EFPY is greater than 200 EF and does not change the required number of capsules to be withdrawn from the IP3 reactor in the current RV materials surveillance program withdrawal schedule.

ASTM E 185-82 requires 5 capsules to be withdrawn when a ΔRT_{NDT} of greater than 200 EF is predicted. The IP3 RV materials surveillance program withdrawal schedule in Section 4.5.2 of Revision 8 of the IP3 FSAR shows that IP3 has a withdrawal schedule of 5 capsules with a total of 8 capsules in the IP3 RV materials surveillance program. The first capsule was withdrawn in the unit's 1978 refueling outage, the second capsule was withdrawn in the unit's 1982 refueling

outage, the third capsule was withdrawn in the unit's 1987 refueling outage and the fourth capsule was removed in May 2003 with a projected neutron fluence of 8.74 x 10^{18} n/cm^2 (E $ 1.0 MeV) after 15.5 EFPY of reactor operation. The withdrawal schedule was revised for SPU conditions in Table 5.1-2 of application report. In this table, the withdrawal schedule for the fifth capsule was not specific. It indicated a range for withdrawal between 16.1 EFPY and 27.1 EFPY. In response to a staff RAI, the licensee indicated that the fifth capsule will be removed during refueling outage 17 (scheduled for 2013). This capsule is projected to have a neutron fluence between 9.22 x 10^{18} n/cm^2 and 1.844 x 10^{19} n/cm^2. These values correspond to the peak end of license vessel fluence and twice peak end of license fluence at SPU conditions, respectively. ASTM E 185-82 requires the fifth capsule be withdrawn at a neutron fluence between the peak end of license fluence and twice the peak end of license fluence. Since the revised schedule for the fifth capsule conforms with the recommendations of ASTM E185-82, it is acceptable. 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 IP3 RV material 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 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 Neutron Fluence, 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 (PT) limits for the plant. Appendix G to 10 CFR Part 50 requires that RCPB materials satisfy the criteria in Appendix G of Section XI of the ASME Code to ensure the structural integrity of the ferritic components of the RCPB is maintained 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 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2.

3.6.2.2 Technical Evaluation

Neutron Fluence

The methodology used to determine the fast (E > 1.0 MeV) neutron fluence is based on the guidance in RG 1.190, “Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,” which was issued in March 2001. Elements of the methodology are also described in WCAP-14040NP-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigation System Setpoints and RCS Heatup and Cooldown Limit Curves.”

The calculations were carried out using the DORT Code, a discrete ordinates transport code in the forward mode using the BUGLE-96 cross section library. BUGLE-96 is based on the ENDF/B-VI cross sections which are recommended in RG 1.190. All forward calculations are based on a P_5 Legendre polynomial expansion and an S_{16} order of angular quadrature. Both the P_5 Legendre polynomial expansion and the S_{16} order of angular quadrature exceed the minimum guidelines specified in RG 1.190. The method derives three-dimensional fluence distributions by synthesis of one- and two-dimensional solutions. This is also in accordance with the guidance in RG 1.190. The neutron sources were derived from cycle-specific calculations which accounted for the power uprate from 3025 to 3067.4 MWt during cycle 12 and from 3067.4 to 3216 MWt scheduled for the end of cycle 13 (i.e., the current cycle). Future cycles, through 27.1 EFPY of operation, were projected to be the same as the equilibrium cycle 16. Finally, the licensee made plant-specific dosimetry comparisons (using this methodology) of measured and calculated values from the plant surveillance capsules. The results documented in Table 7.5-1 of the application report are satisfactory and within the guidelines prescribed in RG 1.190. The staff finds the fluence values acceptable because the methodology used for the estimation of the vessel fast neutron fluence follows the guidance in RG 1.190 and because it is supported by plant-specific measurements.

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 Section XI of the ASME Code. The rule also mandates that the methods used to calculate USE values must account for the effects of neutron radiation 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 material surveillance program.

RG 1.99, Revision. 2, “Radiation Embrittlement of Reactor Vessel Materials,” provides an expanded discussion regarding the calculations of Charpy USE values and describes two methods for determining Charpy USE values for reactor vessel beltline materials, depending on whether or not a given reactor vessel beltline material is represented in the plant’s reactor vessel material surveillance program. If surveillance data is not available, the Charpy USE is determined in accordance with position 1.2 in RG 1.99, Revision 2. If two or more surveillance data are available, the Charpy USE should be determined in accordance with position 2.2 in RG

1.99, Revision 2. These methods refer to Figure 2 in RG 1.99, Revision 2, which indicates the percentage drop in Charpy USE depends upon the amount of copper in the material and the neutron fluence. Since the analyses performed in accordance with Appendix G to 10 CFR Part 50 are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4T), the neutron fluence used in the Charpy USE analysis is the neutron fluence at the 1/4T depth location.

The licensee discussed the impact of the 4.85-percent SPU on the USE values for the RV beltline materials in Section 5.1.2.5 of the application report. In this section, the licensee stated that all RV beltline materials will have a USE greater than 50 ft-lb through the EOL as required by Appendix G to 10 CFR Part 50. Table 5.1-5 of the SPU safety analysis report provides the predicted USE values for all IP3 beltline materials at EOL. The value of USE for the limiting material, Lower Shell Plate B2803-3, was determined based on USE data from surveillance capsules T, Y and Z. The neutron fluences for SPU conditions were calculated using a methodology consistent with the guidance in RG 1.190.

In a November 18, 2004, letter, the licensee provided a revised USE evaluation for the limiting material. The revised evaluation was based on USE data from surveillance capsules T, Y, Z, and X. The data from these capsules are contained in a Westinghouse Report, WCAP-16251-NP, Revision 0, which was submitted to the NRC in a letter dated July 29, 2004. In this analysis, the licensee determined that the USE for Lower Shell Plate B2803-3 was projected to be 52 ft-lb at EOL for SPU conditions.

The NRC staff performed an independent calculation of the EOL USE values for the IP3 RV beltline materials using: (a) the neutron fluence value for the 1/4T location as documented in the SPU safety analysis report for the SPU conditions, (b) the data reported in the licensee's letter dated July 29, 2004, and (c) the methodology documented in RG 1.99, Revision 2. The staff determined that, under the SPU conditions, Lower Shell Plate B2803-3 is the limiting beltline material and calculated a 52 ft-lb USE value for this material at EOL for SPU conditions. This value is in agreement with the limiting 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 staff concludes that the IP3 RV beltline materials will have acceptable USE values under the SPU conditions for the unit.

PT Limit Calculations

Section IV.A.2 of 10 CFR Part 50, Appendix G, requires that the PT 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 PT limits. The rule also requires that the PT limit calculations account for the effects of neutron radiation on the PT 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.

IP3's current PT limits curves are contained in TS Section 3.4.3 and correspond to 34.7 EFPY for conditions prior to the SPU. Section 5.1.2.2 of the application report indicates that the neutron fluence for PT limits in the TSs corresponds to the neutron fluence for 34 EFPY at SPU conditions. Therefore, since the only change in the PT limits is the neutron fluence, the PT

limits in the TSs are applicable for 34 EFPY for SPU conditions. The licensee in a letter dated February 11, 2005 (Commitment NL-05-020-01) committed to revise the TS Bases to delete the reference to the PTLR and to clarify that the PT limit curves are now based on 34.0 EFPY instead of 34.7 EFPY. The PTLR is a licensee-controlled document in which PT limits are calculated by the licensee in accordance with a methodology that was approved by the staff. In addition, the applicant will clarify the basis for labeling the curves for 20 EFPY for applicability to the low-temperature over-pressure protection system (LTOPS) arming temperature. Based on this commitment, the NRC staff finds the PT limits and calculations acceptable.

Fracture Integrity Evaluation

Appendix G of Section III 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 III 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.

The licensee discussed the effects of the SPU on the fracture integrity of ferritic Class 1 components, specifically the RV, SGs, and pressurizer, in Section 5.9 of the application report. The stresses in the RV, SGs 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 application report and were included in the fracture integrity evaluation of Section 5.9 of the application report.

In Table 5.9-3 of the application report, 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 indicates all RV components will meet the requirements of Appendix G of Section III 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 18, 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 using volumetric examination. The licensee provided additional information to confirm that volumetric examination techniques used for previous inspections of the RV outlet nozzle-to-shell welds were consistent with examination techniques used in the technical basis document. The licensee also stated that 3 subsurface flaw indications were identified in the RV outlet nozzle-to-shell weld using these non-destructive techniques during their most recent volumetric exam conducted in September 1999. Each of these flaws were smaller than the postulated 1/5 T flaw. These indications were evaluated to Subsection IWB-3512-1 of Section XI of the ASME Code and were not required to be removed. Since the technical basis document demonstrates a POD of 99.9 percent for flaws less than 1/5T, and the licensee’s non-destructive technique for inspection of the RV nozzle was equivalent to those in the technical basis document, the use of

the 1/5T flaw size for the RV outlet nozzle-to-shell region in the in the ASME Code, Section XI, Appendix G vessel integrity analysis is justified.

In Table 5.9-4 of the application report, the licensee provided the postulated flaw depth values, the calculated stress intensity factor (K_I), and the reference fracture toughness (K_{IR}) for the SG components. Table 5.9-3 indicates all SG ferritic components will meet the requirements of Appendix G of Section III of the ASME Code except for the tubesheet and shell junction, steam outlet nozzle and feedwater nozzle. In a letter dated February 11, 2005, the licensee indicated that the only primary side SG component in Table 5.9-4 that is subject to the requirements of Appendix G of Section III of the ASME Code is the tubesheet and shell junction (the steam outlet and feedwater nozzles are on the secondary side and are not subject to the requirements of Appendix G of Section III of the ASME Code). This letter also provides the results from a revised analysis of the tubesheet and shell junction. In this analysis, the stress intensity factors were calculated using Raju and Newman methods. The applicant indicates the following:

a. The model 44F SG stress report was used as the baselines for assessing the effects of the SPU. The primary and secondary through-wall stresses were added after applying a safety factor of 2 to the primary stresses, and the stress intensity factors were calculated using the combined through-wall stresses. The calculated K_I was then adjusted to incorporate the changes described in Section 5.6 for the affected normal/upset transients. The temperatures for the affected transients are always at

   least 300 EF, so the shell material is always in the upper shelf range of fracture toughness, which is 200 ksi $in^{1/2}$, as for the reactor vessel.

b. The fracture integrity evaluations completed for the SPU for the IP3 SGs have shown that these components are in compliance with the fracture integrity design requirements of Appendix G of the ASME Code. The SG Appendix G analyses were modified to account for the SPU changes and the limiting location flaw depth is 1/4t.

Since all SG primary-side ferritic components meet the requirements of Appendix G of Section II of the ASME Code for the SPU conditions, this issue is resolved for the SGs.

In Table 5.9-5, 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 indicates all pressurizer components will meet the requirements of Appendix G of Section III 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 NRC staff requested that the licensee demonstrate that the pressurizer relief nozzles and pressurizer upper shell would meet the requirements of Appendix G of Section III of the ASME Code for SPU conditions.

To demonstrate the pressurizer safety and relief nozzles and the pressurizer upper shell would meet the requirements of Appendix G of Section III of the ASME Code during SPU conditions, the licensee performed additional fracture mechanics analyses. The revised fracture mechanics analyses are documented in the November 18, 2004, letter from the licensee. The applicant indicates the following:

> The fracture mechanics analysis for the IP3 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, [Section III] 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 [in depth] was again 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 IP3 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 Section III 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 PT limits for the plant. The staff concludes that the licensee has adequately addressed changes in neutron fluence and their impacts on the IP3 RV USE and PT limits for the plant. The staff concludes that the IP3 RV beltline materials will continue to have acceptable USE values, 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 PT limits for operation under the proposed SPU conditions. The NRC staff also concludes that the licensee has adequately addressed the changes to their RCPB fracture integrity evaluation. Based on this assessment, the NRC staff concludes that the IP3 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 during reactor operation. The 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}, 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

Section 50.61 of 10 CFR Part 50 provides the fracture toughness requirements protecting the RVs of PWRs against the consequences of PTS. Licensees are required to perform an assessment of the RV materials' projected values of the PTS reference temperature, RT_{PTS}, through the end of their operating license. The rule requires each licensee to calculate the RT_{PTS} value for each material located within the beltline of the RV. The RT_{PTS} value for each beltline material is the sum of the unirradiated nil ductility reference temperature (RT_{NDT}) value, a shift in the RT_{NDT} value caused by exposure to high energy neutron radiation (i.e., DRT_{NDT} value), and an additional margin value to account for uncertainties (i.e., M value). Section 50.61 of 10 CFR Part 50 also provides screening criteria against which the calculated values are to be evaluated. RV beltline base-metal materials (forging or plate materials) and longitudinal (axial) weld materials are considered to provide adequate protection against PTS

events if the calculated RT_{PTS} values are less than or equal to 270 EF. Reactor vessel beltline circumferential weld materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300 EF. RG 1.99, Revision 2, provides an expanded discussion regarding the calculations of the DRT_{NDT} and the margin value. In this RG, the DRT_{NDT} value is the product of a chemistry factor (CF) and a fluence factor. The fluence factor is dependent upon the neutron fluence and the CF may be determined from surveillance material or from the tables in the RG. If the RV beltline material is not represented by surveillance material, its chemistry factor and the $^{a}RT_{NDT}$ is determined using the methodology documented in position 1.1 and the tables in this RG. The CF determined from the tables in the RG depends upon the amount of copper and nickel in the material. If the RV beltline material is represented by surveillance material, its CF may be determined from the surveillance data using the methodology documented in position 2.1 of RG 1.99, Revision 2. This RG indicates that if the surveillance data gives a higher value of adjusted reference temperature (the adjusted reference temperature at EOL neutron fluence is equivalent to the RT_{PTS} value) than that given by position 1.1, the surveillance data should be used. If the surveillance data gives a lower value of adjusted reference temperature than that given by position 1.1, either may be used. Section 50.61 of 10 CFR Part 50 contains methods of determining adjusted RT_{NDT} values equivalent to RG 1.99, Revision 2.

The licensee discussed the impact of the SPU on the IP3 PTS assessment in Section 5.1.2.4 of the SPU analysis report. Table 5.1-3 identifies the RT_{PTS} values for all RV beltline materials for SPU fluence conditions at 27.1 EFPY (27.1 EFPY corresponds to EOL for IP3 under its present license). The licensee informed the staff in a telephone call on January 27, 2005, that the neutron fluence values in Table 5.1-3 of the application report were incorrect. The licensee provided a revised analysis with the updated neutron fluence values in a letter dated February

3, 2005. The limiting material in the IP3 RV beltline is the Lower Shell Plate B2803-3. The RT_{PTS} value was calculated using the tables in the RG and the surveillance data from Plate B2803-3 (reported and analyzed in WCAP-16212NP). The RT_{PTS} value using the tables in the RG is 264 EF and the RT_{PTS} value using the surveillance data is 258 EF.

The NRC staff performed an independent calculation of the EOL RT_{PTS} values for the IP3 RV beltline materials using the limiting 27.1 EFPY neutron fluence value for the clad-metal interface location of the vessel at SPU conditions. Using the surveillance data from the application report, the staff determined the RT_{PTS} value under the SPU conditions for Lower Shell Plate B2803-3 is 256 EF. Using the tables in the RG, the staff determined the RT_{PTS} value under the SPU conditions for Lower Shell Plate B2803-3 is 265 EF. Both the RT_{PTS} values cited by the licensee and the NRC staff were consistent and are within the PTS screening criteria, as described in 10 CFR 50.61, established for base metal materials.

RG 1.99, Revision 2 indicates that irradiation below 525 EF should be considered to produce greater embrittlement than the values calculated using the RG procedures. Section 5.1.1.2 of the application report indicates that the minimum inlet temperature decreased from 542.2 EF to 517.2 EF for SPU conditions. In an RAI, the NRC staff asked the licensee to determine what impact operating with inlet temperatures below 525 EF would have on the RT_{PTS} value. In its February 11, 2005, response to this RAI, the licensee indicated that they would not operate below 525 EF. Since SPU conditions will result in operating at lower temperatures and the surveillance data was derived from operating at temperatures above SPU conditions, the NRC staff believes that the licensing basis RT_{PTS} value for SPU conditions at EOL should be 265 EF, the value determined from the tables.

The NRC staff, therefore, concludes that if IP3 operates with cold leg temperatures greater than 525 EF, the beltline materials in the IP3 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. In order to ensure that this conclusion remains valid during SPU conditions, the licensee proposed the following license condition:

> With the reactor critical, Entergy shall maintain the reactor coolant system cold leg at a temperature (T_{cold}) greater than or equal to 525 EF. Entergy shall maintain a record of the cumulative time that the plant is operated with the reactor critical while T_{cold} is below 525 EF. Upon determination by Entergy that the cumulative time of plant operation with the reactor critical while T_{cold} is below 525 EF has exceeded one (1) year, Entergy must:
>
> (a) within one (1) month, inform the NRC, in writing, and
>
> (b) within six (6) months submit the results of an analysis of the impact of the operation with T_{cold} below 525 EF on the pressurized thermal shock reference temperature (RT_{PTS}).

This license condition will ensure that the RT_{PTS} value for IP3 will be below the screening criteria for SPU conditions until EOL.

3.6.3.3 Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the IP3 PTS evaluation 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, with the inclusion of the license condition addressed above, 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 structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, core support, 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 IP3 RV internal components in Section 5.2 of the application report. In Section 5.2, the licensee 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 construction code for IP3.

The licensee provided information regarding changes to operating temperature, pressure, flow rates, and neutron fluences resulting from the SPU. The licensee's evaluation indicates that the SPU RCS conditions will not adversely affect the response of RV internals systems and components due to seismic or loss-of-coolant accident excitations. Also, these evaluations demonstrated the IP3 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 assessment of the design core bypass flow limit with the thimble plugging devices removed concluded that the total design core bypass flow with the thimble plugging devices removed was 6.5 percent. Since this is consistent with original design conditions as shown in Table 2.1-1 of the application report, the effect of the SPU on RV internals is bounded by the original design conditions.

The NRC staff's assessment of the impact of design load conditions on RV internals structural integrity and the impact of removing the thimble plugging device on core design bypass flow are discussed in Section 3.4 of this SE. The impact neutron radiation on RV internals follows.

The RV internals of PWR-designed light-water reactors may be susceptible to the following aging effects:

- cracking ! induced by thermal cycling (fatigue-induced cracking), SCC, or irradiation-assisted stress corrosion cracking (IASCC)
- loss of fracture toughness properties ! induced by radiation exposure for all stainless steel grades, or the synergistic effects of radiation exposure and thermal aging for cast austenitic stainless steel (CASS) grades;
- stress relaxation in bolted, fastened, keyed or pinned RV internal components ! induced by radiation exposure and/or exposure to elevated temperatures
- void swelling (induced by radiation exposure).

Table Matrix-1 of NRC Review Standard RS-001, Revision 0, "Review Standard for Extended Power Uprate," provides the staff's basis for evaluating the potential for extended power uprates to induce these aging effects. In Table Matrix-1, the staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels for inducing IASCC in RV internal components are given in WCAP-14577, Revision 1-A. WCAP-14577, Revision 1-A, establishes, a threshold of 1 X 10^{21} n/cm^2 (E $ 0.1 MeV) for the initiation of IASCC and loss of fracture toughness in PWR RV internal components.

The NRC staff requested that the licensee indicate whether the IP3 RV internals will exceed the threshold of 1 X 10^{21} n/cm^2 (E $ 0.1 MeV). In a February 11, 2005, letter (Commitment NL-05-020-02), the licensee indicated that the EOL projected fluence for the IP3 RV internals will exceed the threshold of 1 X 10^{21} n/cm^2 (E $ 0.1 MeV). In response to the need to manage these effects, the licensee has committed to the following:

A. Continue its active participation in the Electric Power Research Institute (EPRI) Materials Research Program (MPR) research initiatives regarding aging-related degradation of reactor vessel components.

B. Evaluate the EPRI recommendations resulting from this initiative and implement a reactor vessel internals degradation management program applicable to IP3.

C. Incorporate the resulting RV internals inspections into the IP3 augmented inspection plan, as appropriate.

D. Submit to NRC for review and approval, the augmented inspection plan that incorporates inspection of the IP3 RV (internals).

In a telephone call on February 15, 2005, the licensee indicated the augmented inspection plan would be submitted within 24 months after the final EPRI MRP recommendations are issued or by March 2010 (based on 5 years from the date of issuance of the IP3 SPU license amendment), whichever comes first.

The EPRI MRP research initiative is an ongoing program to determine the impact of the reactor environment on RV internals integrity. The licensee's commitment to implement the results of this program ensures that the aging effects from neutron radiation on RV internals will be managed for SPU conditions.

3.6.4.3 Conclusion

The NRC staff has evaluated the impact of the SPU conditions on the structural integrity assessments for the RV and RV internals. The staff has determined that the proposed amendment will not significantly impact the remaining safety margins required for the following RCS-related structural integrity assessments: (1) RV Surveillance Program for IP3, (2) USE assessment for the RV, (3) PT limits for the IP3 RV, (4) PTS assessment for the IP3 RV beltline materials, and (5) structural integrity assessment of the IP3 RV internal components. The 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 IP3 proposed power uprate on the performance of primary component materials. The NRC staff reviewed the licensee's evaluation for conformance with the requirements of Appendix G to 10 CFR Part 50, 10 CFR 50.55a, and GDC 1, 4, 14, and 31.

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 application report 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 5.3 EF.

- The maximum increase in the hot leg nozzle temperature due to the proposed power uprate is estimated at 2.2 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 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 Li 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. IP3 plans to maintain lithium levels at 3.5 ppm or less and thus no adverse effects from this aspect of the power uprate are 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 5.3 EF and the maximum increase in the hot leg nozzle temperature to be 2.2 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 (5.3 EF). The calculations showed an estimated 22-percent increase in RVHP penetration susceptibility to PWSCC as a result of the power uprate.

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 (2.2 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 (2.2 EF). The calculations showed an estimated 9-percent increase in the hot leg nozzle weld susceptibility to PWSCC as a result of the power uprate.

In a December 15, 2004, letter, the licensee detailed additional actions being taken to address PWSCC susceptibility increases due to the power uprate. The licensee is required to establish RPV head inspection requirements in accordance with the First Revised NRC Order EA-03-009 (Order). The Order provides for a time-at-temperature methodology to determine the effective degradation years (EDY) value that is used to determine the inspection category. Based on the current plant operating history and cycle-specific temperature data, IP3's expected change in temperature will cause an 11.8% increase in the time-rate-of-change of the EDY value. As

required by the Order, the licensee will recalculate EDY values to establish the inspection requirements for each refueling outage using plant data for each operating cycle.

The licensee is assessing options to mitigate the effects of PWSCC on continued plant operation. One possible option involves a modification that would result in reduction of the RPV upper head temperature. The licensee is also assessing eventual replacement of the RPV upper head.

A similar assessment of PWSCC susceptibility for the RCS hot leg nozzle welds was performed. The licensee is required to inspect these areas in accordance with ASME Code, Section XI and the IP3 Inservice Inspection Program. Also, the licensee is participating in industry programs that monitor operating experience and develop recommendations, including augmented inspections. The Materials Reliability Program has recently issued recommendations that include visual inspection of the Alloy 600 welds within the next two refueling outages.

The licensee concluded that no significant material degradation issues were identified with the RCS materials due to the requested power uprate at IP3 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 (22 and 9-percent, respectively) would be accounted for and addressed through inspection programs.

3.6.5.3 RCS Potential Material Degradation Assessment Conclusion

The NRC staff reviewed the information provided by the licensee and found it acceptable. The NRC staff finds that while the increase in temperature during power uprate conditions at IP3 has an effect on RCS component materials, the licensee's activities to maintain chemistry control and an effective inspection program provide an acceptable level of quality. The NRC 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 NRC 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 IP3 includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping as specified in GDC 4. Section 5.4.2 of the licensee's submittal 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 IP3 power uprate program.

According to the licensee, Westinghouse performed analyses for LBB of IP3 primary loop piping in 1984 and 1997. The results of the 1984 analysis was documented in Fracture Proof Design Corporation Report 80-121, Revision 0. The results of the 1997 analysis was documented in Appendix A of WCAP-8228.

To support the IP3 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, SSE, pressure loads, and normal operating temperature and pressure under power uprate conditions were used in the evaluation. The recommendations and criteria included in the NRC Draft SRP 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 Draft SRP 3.6.3 are as follows:

- Margin of 10 on leak rate
- Margin of 2 on flaw size
- Margin of 1 on loads (using faulted load combinations by the 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 of 1 on load exists using faulted load combinations by the absolute summation method. The evaluation results showed that the LBB conclusions provided in the Fracture Proof Design Corporation Report and Appendix A of WCAP-8228 for IP3 remain unchanged under power uprate conditions.

The licensee determined that the LBB acceptance criteria are satisfied for the IP3 primary loop piping under power uprate conditions. All the recommended margins are satisfied and the conclusions shown in the Fracture Proof Design Corporation Report and Appendix A of WCAP-8228 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 IP3 at the power uprate conditions.

3.6.6.1 LBB Methodology Conclusion

The NRC staff reviewed the information submitted by the licensee concerning the potential impact of the proposed IP3 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 the NRC Draft SRP 3.6.3 would be maintained under power uprate conditions at IP3. Therefore, the NRC staff concludes that the changes to the LBB evaluation for this piping resulting from the proposed power uprate will not alter the NRC staff's previous conclusions stated in the NRC-approved Fracture Proof Design Corporation Report. The NRC staff concludes that, per the provisions of 10 CFR Part 50, Appendix A, General Design Criterion (GDC)-4, the dynamic effects from postulated breaks of the IP3 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 reactor coolant pump 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 licensee 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. However, the licensee noted that the letdown line and excess letdown line radiation dose rates from N–16 will slightly increase, proportional to the increase in reactor power level.

With regard to primary chemistry control, the licensee evaluated the changes in plant parameters as a result of SPU conditions. While changes were made in the range of RCS T_{avg} and RCS T_{hot}, no change in pH was necessary for the SPU. 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 staff concludes that the CVCS is adequate because all of the CVCS systems will operate within their capability limits under IP3 SPU conditions.

3.6.8 Steam Generator 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 SG 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 SG. These samples are used for monitoring water chemistry and for detecting the amount of radioactive primary coolant leakage through the SG 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 230 gpm (continuous normal flow), and 335 gpm (for short periods of operation) per SG. The plant currently operates with a blowdown flow of 37.5 gpm per SG. The blowdown flow rate required to control chemistry and the buildup of solids in the SGs are based on allowable condenser in-leakage, total dissolved solids in the plant circulating water, and the allowable primary-to-secondary leakage. The licensee stated that, since these variables are not affected by the SPU, the blowdown required to control secondary chemistry and SG solids will not be affected by the SPU. The licensee stated that the SG steam outlet temperature and pressure decreases from the original design values of 514.5 EF/774.4 psia to 511.6 EF/754.8 psia at SPU conditions. These slight decreases do not affect the main steam safety valve setpoints nor the design pressure (1085 psig) and temperature (600 EF) of the SGs.

On the basis of its review, the NRC staff finds that the IP3 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 SGs, and the main steam safety valve setpoints are not affected by operation under IP3 SPU conditions.

3.6.9 Steam Generator Structural Integrity

The licensee performed evaluations of the following areas to address the operation of the SGs under SPU conditions: (1) thermal-hydraulic performance, (2) structural integrity of primary- and secondary-side components, (3) tube repair hardware, (4) tube vibration and wear, and (5) tube integrity. The evaluations for SG structural integrity included two primary coolant system average temperatures and two feedwater temperatures for the component in question, and included SG plugging levels of 0 and 10%. The lower primary coolant system average temperature provides for a bounding evaluation to be conducted for the critical components; the two feedwater temperatures represent the feedwater temperature range; and 10% tube plugging represents a conservative maximum level.

The licensee stated that the thermal-hydraulic evaluations, aided in some cases by several computer simulation codes, showed that SPU conditions: (1) cause a small but insignificant decrease in steam pressure, (2) cause a small increase in heat flux, (3) will result in the whole tube bundle being within the nucleate boiling regime and thus no local tube dryout is expected, (4) result in a moisture carryover that will remain well below the 0.10% design limit, (5) have no detrimental effect on damping factor, allowing the SG to operate in a hydro-dynamically stable manner, (6) cause an insignificant change in fluid inventory in the SG during operation, with no effect on operation, and (7) cause an 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 Model 44F SGs are within acceptable ranges for the SPU conditions at tube plugging levels of 10% or less.

With regard to structural integrity, the licensee stated that structural integrity evaluations for the SPU focused on the critical SG components. Critical SG components are identified as the components in which the primary-plus-secondary stress ranges without peak and stress ranges with peak in fatigue calculations, are affected due to the reduction of steam pressure. The reduction in steam pressure results in higher delta-P between primary and secondary side under SPU 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 studs, and steam nozzle. The evaluation included the determination of scale factors, which took into account the baseline analyses maximum stress ranges and fatigue usage factors.

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.

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 delta-P are exceeded for any of the applicable transient conditions under SPU conditions. The licensee stated that the analysis indicated that the maximum normal/upset operating condition primary-to-secondary side differential pressures were below the design limits for normal and upset operating conditions. 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, “long” and “short” ribbed mechanical plugs, and a 40% tube wall undercut for operation under SPU conditions. In each case, the licensee stated that all repair hardware and the 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. In its November 18, 2004, letter, the licensee provided this information, which showed that the weld between the shop weld plug and the tubesheet cladding satisfies the applicable ASME Code requirements 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 and fatigue criteria for SPU conditions. In its November 18 letter, the licensee provided this information, which showed that the mechanical plug designs satisfy the applicable ASME Code requirements for operation under SPU conditions. The licensee was also 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 in the November 18 letter, which showed that the tube undercut qualification satisfies the applicable ASME Code AVs 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.

The NRC staff concludes that the licensee has provided the data necessary to show that the applicable ASME Code requirements are satisfied for the use of tube repair hardware 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 DBA, and included the changes in the thermal-hydraulic

characteristics of the secondary-side of the SGs 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. The licensee also stated that any increase in the rate of tube wear would progress over many cycles and would be observed during normal eddy current inspections, at which time remedial actions could be taken.

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 690, (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 tube rows 1 through 8 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 NRC 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 IP3 SPU conditions.

3.6.10 Regulatory Guide 1.121 Analysis

RG 1.121 analysis 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 the structural limit for an assumed uniform thinning mode of degradation in both the axial and circumferential directions. Tube structural limits were provided. However, the licensee did not conclude whether the revised structural limits support the tube repair limit currently in the TSs. In its November 18, 2004, letter, 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 the licensee's analysis acceptable because it follows the guidance of RG 1.121. The analysis also shows that the existing tube repair limit remains appropriate.

3.6.11 Flow-Accelerated Corrosion Program

Flow-accelerated corrosion (FAC) is a corrosion mechanism which occurs in systems that contain flowing one- 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 by GL 89-08 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.

For large-bore, high-energy piping systems, the licensee stated that EPRI’s CHECWORKS™ computer program is used for FAC predictions for each modeled component within each system. The licensee also stated that the Small Bore and Augmented Monitoring Program addresses piping that has not been modeled using CHECWORKS.™ The licensee stated that the SPU will result in changes in fluid flow velocities and temperatures in the main feedwater and condensate system, heater drains system, main steam system, extraction steam system, and SGBS. Evaluations of the impact of the SPU on FAC indicated that: (1) the majority of piping and nozzle velocities are within standard industry criteria, (2) most of the pipelines and nozzles that had velocities exceeding the standard industry criteria are either included in the FAC program or have been removed from the program due to piping upgrades, (3) a select number of nozzles that exceeded industry-recommended velocities were below the low temperature limit for FAC susceptibility, and (4) one set of operating vent lines will be added to the FAC program due to a change in operating temperature that will result from the SPU.

In response to an RAI regarding the criteria for repairing or replacing components as a result of FAC, the licensee stated that the wear rate and predicted thickness at a future inspection date is calculated. Components with predicted thicknesses greater than or equal to 87.5% of the nominal thickness is acceptable for continued service. For thicknesses less than or equal to 30% of the nominal thickness (for safety-related piping) or less than or equal to 20% of the nominal thickness (for non-safety-related piping), the component is repaired or replaced prior to continued operation. If the predicted thickness falls between these two cases, a structural evaluation is required to ascertain whether the pipe code stress requirements are satisfied.

The NRC staff concludes that the licensee’s criteria for repairing or replacing components as a result of FAC is adequate for operation under SPU conditions.

In response to an RAI regarding how the Small Bore Piping and Augmented Monitoring Program predicts erosion rates in small bore lines, the licensee stated that a wall thinning calculation is performed per ENN-DC-133, “Structural Evaluation of Wall Thinning in Carbon and Low Alloy Steel Piping.” This calculation determines the wear, minimum wall thickness required by the Code, wear rate, and a prediction of the remaining service life of the component.

The NRC staff concludes that the licensee’s utilization of their Small Bore Piping and Augmented Monitoring Program for prediction of erosion rates in small bore lines is adequate for operation under SPU conditions.

In response to an RAI regarding the components most susceptible to FAC under SPU conditions, the licensee provided a table with wear rate calculations for: (a) several components with the highest wear rates under pre-uprate conditions; and (b) several components with the greatest percent increase in calculated wear rates under SPU conditions. The NRC staff noted that, for components with the highest wear rates under pre-uprate conditions, the calculated wear rates decreased under SPU conditions; for certain other components, the calculated wear rates were significantly higher under SPU conditions. When asked in a phone call to clarify these calculations, the licensee indicated that changes in wear rate for a specific component are not proportional to increases in power level, but influenced by flow, temperature, and steam quality local conditions within the flow-carrying components. The licensee also clarified that, for the components with the highest wear rates under SPU conditions, the actual wear rates were calculated to be only about 0.008 in./yr. The licensee stated in Section 10.3 of the application report that the models used in the licensee's FAC Program will be updated to incorporate flow and thermal performance data at SPU conditions.

The NRC staff concludes that the licensee's example calculations and explanation of wear rates for components most susceptible to FAC under SPU conditions is adequate.

On the basis of its review, the NRC staff finds that the licensee's FAC program is acceptable for operation under IP3 SPU conditions because the effects of the SPU 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 staff asked the licensee to: (1) describe the Protective Coatings Program, (2) discuss how the SPU affects the Protective Coatings Program, (3) discuss how the qualification of the Service Level 1 coatings are impacted by SPU temperature and pressure conditions, (4) discuss whether the qualification parameters for the Service Level 1 coatings will continue to be bounded by SPU/DBA conditions, and (5) describe the actions that will be taken if the qualification of Service Level 1 coatings are not bounded by the SPU/DBA conditions, since coating failure could threaten performance of the ECCS sump after a LOCA.

With regard to Item (1), the licensee responded that the coatings program is in conformance with RG 1.54 and American National Standards Institute (ANSI) N101.4-72. Procedure No. TS-MS-013 governs the specification of coatings, including Service Level 1. Procedures SYS-004-GEN, "Qualification of Coating Application Personnel," SYS-005-GEN, "Application of Protective Coating," and SYS-006-GEN, "Coatings Storage and Handling," govern the installation and storage of coatings. With regard to Item (2), the licensee stated that Service Level 1 coatings will continue to be bounded by the DBA parameters specified in ANSI N101.2 during operation under SPU conditions. With regard to Item (3), the licensee stated that Service Level 1 coatings are qualified to the standard PWR DBA temperature/pressure curves. The SPU/DBA conditions are bounded by the standard curves, therefore the qualification of the Service Level 1 coatings are not affected by SPU pressure or temperature conditions. With regard to Item (4), the licensee stated that, since Service Level 1 coatings are qualified to the standard PWR DBA temperature/pressure curves and the SPU/DBA conditions are bounded by the standard curves, there is no effect on the qualification parameters of the coatings. With

regard to Item (5), the licensee stated that no actions need to be taken for the qualification of Service Level 1 coatings because the SPU/DBA conditions are bounded by the standard PWR DBA temperature/pressure curves.

On the basis of its review, the NRC 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, the impact of IP3 SPU conditions on the protective coatings will be negligible.

3.7 Plant Systems

3.7.1 Regulatory Evaluation

The NRC staff's review in the area of plant systems covers the impact of the proposed SPU 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 analyses 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 SPU. Guidance for the NRC staff's review of plant systems is contained in SRP Chapters 3, 6, 9, 10, and 11.

3.7.1.1 LOCA Mass and Energy Release to Containment

Section 6.5.1.7 of the application report discusses the acceptance criteria for the LOCA mass and energy release. Appendix A, "General Design Criteria for Nuclear Power Plants," and Appendix K, Paragraph I.A, "Sources of heat during the LOCA," were cited as the criteria for the power sources considered in the analyses.

In addition, GDC 4 applies and requires that structures, such as the walls of subcompartments inside containment, shall be appropriately protected from the dynamic effects associated with pipe ruptures.

3.7.1.2 LOCA Containment Response

In Section 6.5.3.4 of application report, the licensee cites the following criteria for the containment response to the DBLOCA:

- For GDC 10, FSAR Chapter 5.1 requires the containment to be designed to withstand a large reactor coolant system pipe break without loss of integrity.

- For GDC 49, FSAR Section 5.1 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.

- For GDC 52, FSAR Chapter 9.1 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.

- Chapter 14.3 of the FSAR requires that the calculated containment accident pressure at 24 hours be less than 50 percent of the peak calculated pressure.

3.7.1.3 Main Steam Line Break (MSLB)

For the MSLB accident, the application report lists the following GDC 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.

3.7.2 Technical Evaluation

In conformance with GDC 10, 16, 38, 49, and 52, the pressure and temperature within the containment must remain below the containment's design pressure (47 psig) and design temperature (271 EF) following a postulated LOCA and a postulated MSLB at SPU conditions.

3.7.2.1 LOCA Containment Response

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

3.7.2.1.1 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 a RCS pressure of 2299 psia and a vessel/core inlet temperature of 511.8 EF. This is a high value of pressure and a low value of temperature, which is conservative for these calculations since this tends to overestimate the mass released from the break.

The NRC has approved the LBB methodology for IP3. RCS piping was determined not to catastrophically rupture according to the LBB methodology and, therefore, does not have to be considered in subcompartment analyses. Consequently, as described in Section 6.5.2.2 of the application report, only branch lines to the RCS were considered. The application report states that the increase in subcompartment pressurization due to the lower RCS temperatures associated with the SPU resulted in a 72.9 percent margin to the current analysis of record.

Since IP3 is approved for LBB, as discussed in Section 6.5.2.1 of application report, and the short-term calculations were conservatively done, the short-term LOCA calculations are acceptable. Compliance with the guidance in GDC 4 with respect to subcompartment analysis is maintained with the SPU.

3.7.2.1.2 LOCA Long-Term Response

The mass and energy discharged from the break into containment are calculated using methods previously approved by the NRC.[2] Using these methods, the licensee calculated the long-term response of the IP3 containment to the LOCA. These calculations were performed with the Westinghouse containment code COCO,[3] which has been previously approved by the NRC.

Table 6.5-23 of the application report provides the initial conditions used for the containment analyses. These values have been conservatively selected. Table 6.5-34 of the application report 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 IP3 long-term pressure and temperature containment LOCA responses are acceptable.

Table 6.5-34 of WCAP 16212-P

LOCA Containment Response Results for IP3 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 ECCS	42.00	260.4	13.27	187.8
Double Ended Pump Suction/ Maximum ECCS	38.94	256.2	12.4	183.6
Double Ended Hot Leg	40.38	258.6	NA	NA

3.7.2.1.2 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 the IP3 SGs is 1.4 ft^2.

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

3 Containment Pressure Analysis Code (COCO), WCAP 8327-P (Proprietary) and WCAP 8326 (Non-Proprietary), July 1974

The MSLB calculations for IP3 were done using Westinghouse methods which have been previously approved by the NRC (Section 6.6.6 of application report).

As described in Section 6.6.1.2 of the application report, conservative input values have been assumed for these analyses. It is necessary for the main steam line break accident calculations to examine a range of powers and single failure assumptions. These are also described in Section 6.6.1.2 of application report. Since a single failure is included in the mass and energy release calculations, no single failure is modeled in the containment response calculations. This is the typical procedure for this calculation and it is acceptable for IP3.

The main steam line double-ended rupture peak containment pressure is 39.12 psig with the single failure of a feedwater control valve (Table 6.6-10 of WCAP-16212-P). This is less than the containment design pressure and is therefore acceptable.

3.7.2.1.3 Generic Letter (GL) 96-06

GL 96-06 addressed three issues: susceptibility of containment air cooler cooling water systems to either (1) water hammer, or (2) two phase flow, and (3) overpressurization of containment piping penetrations due to thermal expansion of fluid between closed isolation valves. The first two issues were discussed in Section 3.4 of this SE. The third issue is addressed here.

During the review of GL 96-06 for IP3, 13 piping segments were found to be subject to overpressurization resulting from either, or both, the LOCA conditions in containment and high energy line breaks in the primary auxiliary building. Corrective actions restored these penetrations to within the allowable stress limits. An August 25, 2003, NRC letter to the licensee concluded that the licensee's evaluation was acceptable.[4]

Section 10.11 of application report addresses the GL 96-06 issue of overpressurization of containment piping penetrations for the stretch power uprate. The licensee performed an evaluation of the lines and associated containment isolation valves determined to be potentially susceptible to thermal pressurization from a LOCA and a primary auxiliary building high energy line break and concluded that the stretch power uprate does not affect the conclusions of the August 25, 2003, letter since the maximum temperature used for the evaluations bounds the predicted temperatures for these events under stretch power conditions.

Based on the results of the licensee's evaluation, the NRC staff finds that the licensee continues to satisfy the requested actions of GL 96-06.

3.7.2.1.4 Proposed Changes to the IP3 Containment TSs

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[4] Letter to Mr. Michael R. Kansler, President, Entergy Operations, Inc., from Patrick D. Milano, USNRC, "Closeout of responses to Generic Letter 96-06, Indian Point Nuclear Generating Unit Nos. 2 and 3," August 25, 2003.

The peak calculated pressure resulting from the DBLOCA at stretch power uprate conditions is 42.0 psig. The licensee proposed, in compliance with 10 CFR Part 50, Appendix J, to use this value for P_a.[5]

Since the proposed change to the TSs is in compliance with the applicable regulation and consistent with the safety analyses, the proposed change is acceptable.

3.7.2.1.5 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 acceptable since acceptable methods and conservative assumptions were employed and the applicable regulations in the GDCs remain satisfied.

3.7.2.2 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) GDC-3, insofar as it requires that the reactor facility be designed to (a) minimize the probability of events, such as fire and explosions, and (b) 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 RS-001.

In NRR RS-001, Rev. 0, "Review Standard for Extended Power Uprates," Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," 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

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[5] P_a is defined in Option B to 10 CFR Part 50 Appendix J as: the calculated peak containment internal pressure related to the design basis loss-of-coolant accident as specified in the technical specifications. P_a is the pressure used for containment leakage rate testing.

capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe shutdown procedures."

Section 10.1, "Fire Protection 10 CFR 50 Appendix R Program," of the application report addresses the fire protection guidelines of RS-001. This information satisfactorily demonstrates the licensee's compliance with Sections III.G and III.L of Appendix R to 10 CFR Part 50 and 10 CFR 50.48.

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 fire protection program will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDC-3 following

implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to fire protection.

3.7.2.3 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 Section 10.2.1 of the application report, and major components include the main steam safety valves (MSSVs), power-operated atmospheric relief valves (ARVs), condenser steam dump valves, 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 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 IP3 are capable of performing their design functions under SPU conditions. The licensee also confirmed that an inadvertent opening, with failure to close, of the largest of any single steam dump, relief, or safety valve will not prevent the safe shutdown of the plant. Under the current plant design conditions, the maximum capacity of any single MSSV, ARV, or main steam dump valve does not exceed 890,000 lb/hr at 1085 psig inlet pressure. This feature limits the potential uncontrolled blowdown flow rate in the event a valve inadvertently fails or sticks in the open position. This maximum blowdown rate will not change for SPU. Other areas

of the MSS that are impacted by the proposed power uprate such that reactor safety considerations could potentially be affected and are discussed below.

3.7.2.3.1 Main Steam (MS) 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 licensee calculated the pressure drop from the SG to the HP turbine inlet throttle valve 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 proposed SPU operating conditions. The licensee also concluded that the MSS can withstand the steam hammer loads associated with SPU conditions.

3.7.2.3.2 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.

3.7.2.3.3 MSIVs and Non-Return Valves

The MSIVs and non-return valves for IP3 are located outside the containment and downstream of the MSSVs. The safety function of the MSIVs and non-return valves is to prevent the uncontrolled blowdown of more than one SG and they must be able to close within 5 seconds or less in the event of an MS line rupture. Because the MSIVs and non-return valves at IP3 are check valves, steam flow assists in closing these valves when they are actuated to perform their respective isolation functions. Therefore, under the SPU conditions of increased steam flow, the valves will continue to meet their design capability of closing in 5 seconds or less.

3.7.2.3.4 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 FSAR 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.

3.7.2.4 Condensate and Main Feedwater Systems

The condensate and main feedwater (FW) systems consist of three one-third capacity condensate pumps, three condensate booster pumps, two half-size heater drain pumps, and two half-size turbine-driven main FW (MFW) pumps. The condensate system (CS) transfers condensate from the main turbines and low-pressure heater drains that collect in the hotwell through the condensate polisher and five stages of feedwater heaters to the suction side of the

main FW pumps. The two heater drain pumps take a suction from the heater drain tank, where the drains from the high-pressure heaters are collected, and discharge into the condensate header upstream of the MFW pumps. The MFW pumps increase the pressure of the condensate and deliver the MFW to the SGs via the final stage of the high pressure heaters and FW regulating valves. The FW system controls FW flow via the FW regulating valves and the FW pump turbine speed control system. The CS and FW systems are described in IP3 FSAR Section 10.2.6.

The licensee evaluated the CS and FW systems 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 condensate and FW systems 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.

The NRC staff's review of SPUs focuses primarily on the capability to isolate feedwater to the SGs during postulated accident conditions. The FW regulating and isolation valves are located outside containment and are designed to isolate FW flow to the SGs following unisolable steam (or feedwater) 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 reactor coolant system. The results of the licensee's analysis indicated that while feedwater 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. Therefore, based on the information that was provided, the NRC staff finds the proposed SPU acceptable with respect to feedwater isolation considerations.

3.7.2.5 Service Water System & Ultimate Heat Sink

The Hudson River is the ultimate heat sink (UHS) for IP3. The IP3 service water system (SWS) is designed to supply cooling water from the Hudson River to various heat loads, including 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 LOOP and/or a LOCA. The IP3 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 Table 9.6-1 of the FSAR, and also in Section 9.6.1 of the application report. 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. Three service water backup pumps are provided that take suction from the IP3 discharge canal and discharge through an essential header. Portions of the SWS are safety related.

The proposed SPU will 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), 18 percent degraded pump curves, and atmospheric vents where applicable. As discussed in Section 9.6 of the application report, the licensee found 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 discussed in Section 11 of the application report, the licensee has assessed the impact of the proposed power uprate on the resolution of the GL 96-06 waterhammer and two-phase flow issues. 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 1 percent) decrease in accident peak containment temperature and/or the small expected increase in containment fan cooler units (CFCU) cooling water outlet 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 conclusions of existing IP3 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 IP3.

3.7.2.6 Auxiliary Feedwater (AFW) System

The AFW system supplies feedwater to the secondary side of the SGs when the normal feedwater supply is not available. The system removes decay heat from the reactor core by heat exchange in the SGs when the MFW pumps are not functional, thereby maintaining the required heat sink for the RCS. The system provides feedwater 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 LONF or during a secondary system pipe break.

The AFW system consists of two MDAFW pumps and one TDAFW pump, and associated valves, piping, and controls to enable the AFWS to satisfy single active failure and diversity considerations. The AFW system at IP3 feeds all four SGs. The AFW system consists of two distinct safety-grade pumping subsystems, one supplied by the TDAFW pump and the other supplied by the two MDAFW pumps, in order to assure reliability of the AFW supply. At the current (pre-SPU) power level, the TDAFW subsystem has sufficient SG makeup capacity for dissipating 200 percent of the maximum reactor decay heat while feeding all four SGs, and each of the two MDAFW pumps has sufficient SG makeup capacity for dissipating 100 percent of the maximum reactor decay heat while feeding two of the four SGs. Following

implementation of the proposed power uprate, the licensee determined that, for the design basis analysis for the LONF event, additional AFW flow must be credited within 10 minutes after the low-low SG level reactor trip occurs in order to assure that the pressurizer will not go water-solid. This is a reduction in the degree of redundancy described in the TS Bases for the AFW system, and redundancy was a consideration in the establishment of the LCO. However, the licensee stated that a best-estimate analysis of the same event continues to indicate that a single MDAFW pump provides adequate decay heat removal to prevent the pressurizer from reaching a water-solid condition. Based on the results of the best-estimate analysis and the current, short 72-hour allowed outage time for a single inoperable AFW pump, the NRC staff finds that the existing AFW system LCO remains acceptable for the operation at the uprated power level.

By design, AFWS flow will be initiated automatically from both motor-driven AFW pumps and the turbine-driven pump starts without producing flow following any LONF event, including one that is concurrent with a LOOP. The licensee's analysis of the worst-case LONF event shows that the AFWS is capable of removing the stored and residual reactor heat plus reactor coolant pump heat, thus preventing overpressurization of the RCS and the SG secondary side, water relief from the pressurizer, and uncovery of the reactor core. The design basis single failure of one of the two motor-driven AFW pumps to automatically start results in only one motor-driven AFW pump starting and supplying 343 gpm feedwater flow distributed equally between two of the four SGs. Following implementation of the proposed power uprate, the licensee credits additional feedwater flow by either aligning the TDAFW pump or starting the idle MDAFW pump within 10 minutes after the low-low SG level reactor trip occurs in order to assure that the pressurizer will not go water solid. Initiation of AFW flow from these pumps requires manual operator actions that were not previously required to provide adequate AFW flow. These operator actions are discussed in Section 3.8 of this SE.

Based on its evaluation of system functional requirements for accidents and transients, the licensee determined that the design pressures and temperatures of the AFWS piping, valves, and components will continue to be bounding for SPU operation, and the AFW pump design criteria will continue to be satisfied.

The normal (short-term) water supply for the AFW pumps is the safety-grade condensate storage tank (CST), and a LOOP is the most limiting event with respect to CST inventory. In accordance with the plant-design basis, enough usable water must be available in the CST to dissipate the reactor decay heat following a reactor trip from full power operation concurrent with a LOOP in order to cool the plant to hot standby conditions and maintain the plant in hot standby for at least 24 hours. The licensee has determined that the minimum required usable CST inventory that is needed in order to satisfy this criterion following the proposed power uprate is 292,200 gallons. Current TS 3.7.6 for IP3 requires that a minimum usable inventory of 360,000 gallons be maintained in the CST which exceeds the amount needed for SPU operation and will continue to be sufficient for SPU operation.

Based on a review of the information that was provided, the NRC staff has determined that the licensee has adequately considered and addressed the impact of the proposed power uprate on the ability of the AFWS to perform its safety function. The NRC staff finds that the AFWS will continue to satisfy its licensing basis following implementation of the proposed power uprate and therefore, the proposed SPU is considered to be acceptable with respect to the AFWS.

3.7.2.6 Spent Fuel Pool Cooling System

As described in Section 9.3 of the IP3 UFSAR, the spent fuel pool (SFP) cooling loop at IP3 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 pool (the other pump is on standby), and circulates the water through the heat exchanger and returns it to the pool. CCW cools the heat exchanger. The SFP cooling loop piping is arranged so that a failure of any pipe does not drain the SFP below the stored fuel elements.

The function of the SFP cooling system (SFPCS) is to remove decay heat from the spent fuel assemblies stored in the SFP. The licensing design basis of the SFPCS was established by Amendment 90 on October 12, 1989. The design refueling batch condition consisted of an offload of 76 freshly discharged fuel assemblies with 193 storage locations empty for a full core discharge reserve and the remaining spaces of the fuel rack filled with previously discharged fuel assemblies. The calculated heat load for this discharge was 17.48 x 10^6 BTU/hr using Branch Technical Position ASB 9-2, and this heat load resulted in an equilibrium pool temperature of 150 EF assuming a service water temperature of 95 EF and conservative performance of the SFPCS heat exchanger. Likewise, the design full core offload condition consisted of a full core discharged 268 hours after shutdown and the remaining spaces of the fuel rack filled with previously discharged fuel assemblies. The calculated heat load for this discharge was 35.00 x 10^6 BTU/hr using Branch Technical Position ASB 9-2, and this heat load resulted in an equilibrium pool temperature of 200 EF assuming a service water temperature of 95 EF and conservative performance of the SFPCS heat exchanger. The application for amendment from the licensee dated May 9, 1988, stated that these results were acceptable based on the conservatisms in the decay heat calculation methodology, the assumed irradiation time, the pool temperature modeling assumptions, and the worst-case extreme assumptions for service water temperature and heat exchanger performance. The staff accepted these analyses.

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 each fuel assembly loaded into the SFP. In Section 4.1.7, Attachment III of the June 3 application, the licensee indicated that cycle-specific comparisons of heat load to expected heat removal capacity at a SFP temperature of 200 EF would be performed, and the licensee stated that fuel transfer would be controlled to limit the heat load to a value below the calculated heat removal capacity. However, in a letter dated November 18, 2004, the licensee clarified that cycle-specific heat load evaluations using Branch Technical Position ASB 9-2 would be performed and evaluated against the design basis maximum heat load. Based on the actual inventory of previously discharged fuel within the SFP, the evaluation will determine the number of assemblies that can be transferred into the SFP for a given time after reactor shutdown such that the total decay heat load within the SFP remains below the design basis limit of 35.00 x 10^6 BTU/hr. If the actual number of assemblies transferred reaches the limit calculated by the cycle-specific evaluation for the 35.00 x 10^6 BTU/hr heat load, the licensee stated that further movement of fuel from the reactor into the SFP will be delayed until the fuel has decayed to a point where the SFP heat load limit would not be exceeded. With the exception of using the actual inventory of fuel rather than a fuel offload scenario, this method maintains the existing licensing basis for spent fuel cooling. 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 conservative methods and assumptions used in the licensing basis SFP temperature

evaluation ensure the actual maximum SFP temperature will be well below the 200 EF design basis limit. In addition, the licensee stated that supplemental cooling will be routinely employed to maintain SFP bulk temperature below the normal alarm limit of 135 EF during full-core offload conditions. The NRC staff finds this method of administrative control of SFP conditions consistent with the existing licensing basis and, therefore, is acceptable.

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 150 EF, the time-to-boil would be 4.9 hrs and the required make-up capacity would be 60 gpm. For the full core offload, with an initial SFP temperature of 200 EF, the time-to-boil is at least 33 minutes and the maximum required makeup capacity would be 100 gpm. However, in response to questions that were raised by the NRC staff, the licensee confirmed that the time-to-boil for the full core offload case will be maintained at 49 minutes, which is consistent with the existing plant licensing basis that was approved by NRC in Amendment 90. Also, consistent with the existing licensing basis, the licensee credits the primary water storage tank, the refueling water storage tank, 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 and 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 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.

3.7.2.7 Steam Dump System

The steam dump system provides a steam flow path directly to the condenser 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 recognized in FSAR Section 10.2.1.1 and as described in Section 4.2.2 of the application report, the Westinghouse sizing criterion specifies that the steam dump system (valves and piping) be capable of discharging 40 percent of the rated steam flow at full-load steam pressure to permit the NSSS to withstand an external load reduction of up to 50 percent of plant-rated electrical load without a reactor trip.

According to Section 4.2.2, an evaluation of the steam dump system indicated that the existing system capacity could be reduced to as low as 29.4 percent of the SPU full load steam flow at the current minimum allowable steam pressure of 567 psia and corresponding Tavg values that are lower than 549 EF. Higher values of Tavg result in higher steam pressures, thereby increasing the steam dump capacity and as the full-power Tavg is increased, larger load rejections can be successfully accommodated without resulting in a reactor trip. According to Section 4.3.1.3.3 of the application report, the licensee's analyses demonstrated that for

full-power Tavg values of 564 EF and above, the 50 percent design-basis load rejection capability is satisfied. Because the plant will operate at a full power Tavg of 567 EF, the licensee concluded that the 50-percent load rejection criterion will continue to be satisfied following the proposed power uprate. The NRC staff considers this acceptable.

3.7.2.8 Component Cooling Water (CCW) System

As described in Section 9.3 of the FSAR, the CCW system is credited for providing cooling water to various plant components during plant normal, shutdown, and post-accident operations. The CCW system 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 report, the limiting heat loads for CCW system occur during normal plant operations, the 10 CFR 50 Appendix R (fire protection) cooldown, and during post-LOCA plant cooldown. The SFP is the only heat load with a potential to affect the CCW system following power uprate. The licensee has evaluated the CCW system and its components and has determined that the existing CCW system capability is adequate for the proposed SPU conditions with no equipment changes, and historical CCW system supply temperature limits will be maintained for the proposed power uprate. Based on these considerations, the staff finds the proposed power uprate to be acceptable with respect to the CCW system.

3.7.2.9 Main Turbine

As discussed in Section 8 of the application report, the licensee has 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 for the low-pressure turbines at this time.

The NRC staff's review focuses 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, the NRC staff finds that design features that have been established for preventing turbine overspeed are not being modified and are not affected by the proposed power uprate, and existing surveillance testing requirements will confirm that these protective features continue to be acceptable. Because the existing turbine overspeed protective devices will continue to prevent the main turbine from exceeding design specifications, the existing turbine missile impact analysis remains valid. Consequently, these areas are not affected by the proposed power uprate and will continue to be acceptable following SPU implementation.

3.7.2.10 Internally Generated Missiles Outside Containment

The potential sources of internally generated missiles outside containment include pipe fittings, bolts, valve bonnets, and other components. The potential for turbine missiles is addressed in

Section 3.7.2.9 of this SE. 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 staff finds that existing analyses pertaining to protection of SSCs important to safety from internally generated missiles outside containment are not affected by the proposed power uprate and remain valid.

3.7.2.11 Flooding

The licensee evaluated the impact of the proposed power uprate on the existing flooding analysis as described in Section 10.4 of the application report. The existing flooding analysis for IP3 considers the failure of seismic Class III (non-seismic) lines as well as failures due to postulated interactions between seismic Class II and Class III piping. Based on a review of the previous flooding analysis, Entergy found that the flooding of the AFW pump rooms could potentially be affected due to the increased feedwater system flow rate. Increased flooding in the area outside the AFW pump room could result due to a postulated HELB in the main feedwater system. The licensee installed a flood control gate in an access door for the AFW pump room and another flood control gate was installed in a door located in the general vicinity of the postulated pipe. These flood control gates will drain any water from these areas to the outside yard area so that flooding will not occur. The licensee also found that flooding due to failure of the SG blowdown system (SGBS) seismic Class III lines could potentially be affected by SPU. In this case, the nominal blowdown flow following a postulated break in the SGBS piping would increase by about 6 percent. However, the licensee concluded that this relatively small increase in flow would not significantly impact the existing flooding analysis for the primary auxiliary building because the flood level would only increase by about 4 to 5 inches and remain below the acceptance criterion of 4 feet. Based on a review of the information that was provided, the NRC staff finds that the licensee has adequately evaluated and addressed the potential impact of the proposed power uprate on flooding and considers the proposed SPU acceptable in this regard.

3.7.2.12 High Energy Line Break (HELB)

As discussed in Section 9.9 of the application report, the licensee indicated that changes to operating pressures, temperatures, and flow rates for high and moderate energy piping systems remain bounded by existing analyses. Consequently, the proposed power uprate will not result in new pipe break locations that could potentially impact additional SSCs important to safety that were not previously affected. Therefore, based on the information that was provided, the NRC staff finds that the proposed power uprate is acceptable with respect to protection of SSCs important to safety from postulated high energy line breaks.

3.7.3 Summary

The licensee has evaluated the impact of the proposed stretch power uprate on BOP systems and components, demonstrating that reactor safety will not be degraded at IP3 by the proposed power uprate to 3216 MWt. Based on the information that was provided and the considerations that are discussed in this evaluation, the NRC staff has determined that the licensee has adequately considered and addressed the effects of the proposed power uprate on the BOP areas of review, and that IP3 will continue to satisfy its current licensing basis in these areas following SPU implementation. Therefore, with respect to the BOP areas of review, the NRC

staff considers the licensee's request to increase the licensed power level of IP3 to 3216 MWt acceptable.

3.8 Human Factors

3.8.1 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(l) and (m), which provide requirements for staffing of reactor operators, 10 CFR 50.120, which specifies training and qualification requirements for nuclear power plant personnel, and 10 CFR 55.59, which requires periodic requalification of reactor operators.

3.8.2 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 June 3, 2004, application. Following is a summary of the licensee's responses and the NRC staff's conclusions.

3.8.2.1 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.

3.8.2.2 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.

3.8.2.3 Control Room Controls, Displays, and Alarms

As described in the June 3, 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.

3.8.2.4 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.

3.8.3 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(l) 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.

4.0 LICENSE AND TS CHANGES

For the IP3 SPU program to increase the maximum power level from 3067.4 to 3216 MWt, the application includes proposed changes to the rated thermal power (RTP) in the TS Definition, the reactor core safety limits in TS 2.1, and several LCOs. These proposed TS changes are evaluated below.

The licensee also proposed to adopt Technical Specification Task Force (TSTF) Change Traveler No. TSTF-339 to relocate to the core operating limits report (COLR) the following cycle-specific parameters: (1) Figure 2.1-1 in TS 2.1.1, Reactor Core Safety Limits; and (2) values of the constants in the overtemperature ΔT (OTΔT) and overpower ΔT (OPΔT) functions in LCO 3.3.1; and (3) the departure from nucleate boiling (DNB) parameters in LCO 3.4.1.

Section 50.36(c)(2)(ii) specifies four criteria in determining what must be included in the TS LCO, including any process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis. As such, license amendments are generally required each fuel cycle to update the values of cycle-specific core operating parameter limits in TSs. To eliminate the need for a license amendment to update these cycle-specific parameter limits each fuel cycle, while meeting the requirements of 10 CFR 50.36(c)(2)(ii), the NRC has allowed licensees to use an alternative to incorporate the cycle-specific operating parameter limits in the COLR. GL 88-16, "Removal of Cycle-Specific Parameters Limits from Technical Specifications," provides the COLR-implementation guidance. The staff also approved topical report WCAP-14483-A, "Generic Methodology for Expanded Core Operating Limits Report," to further relocate to the COLR (1) TS Figure 2.1-1 in TS 2.1.1, (2) values of the cycle-specific parameters in the over-temperature ΔT and over-power ΔT functions in TS Table 3.3.1-1, and (3) the limit values of the RCS DNB parameters for pressure, RCS average temperature, and total flow rate in LCO 3.4.1. TSTF-339 was approved by NRC to implement the expanded COLR methodology of WCAP-11483-A. In the evaluation of the relevant TS changes below, the NRC staff finds that the IP3's adoption of TSTF-339 for relocation of these parameters to the COLR is consistent with GL-88-16 and TSTF-339, and is acceptable.

4.1 Change to Facility Operating License No. DPR-64

4.1.1 TS 1.1, Definition

The IP3 TS 1.1, Definition, specifies that Rated Thermal Power (RTP) shall be a total reactor core heat transfer rate to the reactor coolant of 3067.4 MWt. The proposed change would amend the RTP from 3067.4 to 3216 MWt. The increase of the RTP to 3216 MWt is supported by the appropriate safety analyses described in the licensee's June 3, 2004, application report and is acceptable based on the NRC staff evaluation of the safety analyses described in Section 3.0 of this report.

4.1.2 License Condition No. 2.AB

As discussed in Section 3.6.3.2 of this SE, the following condition will be added under section 2 of the facility operating license:

AB. With the reactor critical, Entergy shall maintain the reactor coolant system cold leg at a temperature (T_{cold}) greater than or equal to 525 EF. Entergy shall maintain a record of the cumulative time that the plant is operated with the reactor critical while T_{cold} is below 525 EF. Upon determination by Entergy that the cumulative time of plant operation with the reactor critical while T_{cold} is below 525 EF has exceeded one (1) year, Entergy must:

(a) within one (1) month, inform the NRC, in writing, and

(b) within six (6) months submit the results of an analysis of the impact of the operation with T_{cold} below 525 EF on the pressurized thermal shock reference temperature (RT_{PTS}).

4.2 Change to TS 2.1.1, Reactor Core SLs

TS 2.1.1 specifies that in MODES 1 and 2, the combination of thermal power, reactor vessel inlet temperature, and pressurizer pressure shall not exceed the safety limits (SLs) specified in Figure 2.1-1. The proposed change would relocate Figure 2.1.1 to the COLR, and add new requirements 2.1.1.1 and 2.1.1.2 for DNB and peak fuel centerline temperature limits as follows:

"In MODES 1 and 2, the combination OF THERMAL POWER, Reactor Vessel inlet temperature, and pressurizer pressure shall not exceed the limits specified the COLR; and the following SLs shall not be exceeded:

2.1.1.1 The departure from nucleate boiling ratio (DNBR) shall be maintained $ 1.17 for the WRB-1 DNB correlations.

2.1.1.2 The peak fuel centerline temperature shall be maintained < 5080 °F, decreasing by 58 °F per 10,000 MWD/MTU of burnup."

This revision is an adoption of TSTF-339. Figure 2.1-1, which provides limits on RCS temperature as a function of pressurizer pressure and fractional RTP, was originally included in the TS based on the interpretation of safety limits. Section50.36 of 10 CFR Part 50 states that safety limits for nuclear reactors are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain physical barriers that guard against the uncontrolled release of radioactivity. However, as stated in the staff's SE on WCAP-14483-A, the figure is not a complete representation of reactor core safety limits but is intended to provide the relationship between the process variables that are available to the operator (i.e., T-avg, pressurizer pressure, and thermal power) and the DNB design basis safety limit. In addition, Figure 2.1-1 is based on cycle-specific parameters such as the nuclear enthalpy rise hot channel factor limit. Therefore, the staff approved the WCAP-14483-A methodology in retaining the requirement for a reactor core limit figure in TS 2.1.1, but relocate the actual figure to the COLR and replace it with the DNB design limit and the fuel centerline melt limit, which are the true safety limit. In addition, to comply with the guidance of GL 88-16, which specifies that the approved methodologies used to determine the cycle-specific values be referenced in the TS, the LAR would also add to TS 5.6.5 Topical Reports WCAP-11397-P-A and WCAP-8745-P-A, which are approved methodologies for thermohydraulic safety analysis of DNBR and determination of the OTΔT and OPΔT trip functions.

The NRC staff finds that the revised TS 2.1.1 is consistent with TSTF-339, WCAP-14483-A, and GL 88-16, and is, therefore, acceptable.

4.3 Changes to LCOs

The proposed amendment would revise several TS LCOs, including changes to the allowable values (AVs) of several reactor trip system (RTS) trip functions and engineered safety features actuation systems (ESFAS) functions, the relocation of the cycle-specific parameters to the COLR, and changes to the limiting values of pressurizer water level. The NRC staff evaluation of each of these proposed changes is described below.

4.3.1 TS 3.3.1 Reactor Trip System Instrumentation

The proposed amendment would change the AVs of several RTS trip functions in TS Table 3.3.1-1. The AV of a trip function is a value that the trip setpoint might have when tested periodically (due to instrument drift or other uncertainties associated with the test), beyond which the instrument channel would be declared inoperable. In Table NL-04-073-IC-4-1 in Attachment 2 to its letter dated November 18, 2004, the licensee provided a summary of trip functions whose AVs are to be revised, and comparisons of the values between the existing and SPU conditions of the safety analysis limits (SAL), nominal trip setpoints (NTS), and NTS AVs, as well as total allowance, channel uncertainties, and setpoint margins for the SPU conditions. Attachment 2 to the November 18 letter also provided supporting calculations of the specific channel uncertainties and AV for each of these trip functions. These calculations were performed based on the methodology described in ANSI/ISA-RP67.04.2-2000, which describes three methods for the NTS and AV calculations. The AVs used for this amendment are based on the calculations with Method 2, which the staff has determined to be acceptable. Using Method 2, the AV and NTS are determined by adding to the SAL the respective channel uncertainties calculated in accordance with the setpoint methodology. The licensee also stated that its uncertainty calculations include certain uncertainties not accounted for in the ISA-RP67.04.2 method, and are therefore more conservative. The NRC staff evaluation of these AV changes is 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 109.0% RTP to 111.0% RTP with the SAL and NTS remaining unchanged at 118% and 108% RTP, respectively, to ensure that the licensing basis acceptance criteria of DNBR limit is met. Attachment 2 to NL-04-145 provides the calculations of instrument channel uncertainties, NTS and AV of this trip function for the current cycle. With the SAL and NTS of 118.0% and 108.0% RTP, respectively, the AV was calculated to be 114.4% RTP, which shows the a margin of 5.4% RTP in the current AV of 109% RTP. Therefore, the proposed SPU AV of 111% is justified by the instrument loop uncertainty, and is acceptable.

(2) Functions 5 and 6, Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT):

The OTΔT and OPΔT trip functions, respectively, provide DNB and fuel centerline melt protections against non-LOCA transients. Notes 1 and 2, respectively, in TS Table 3.3.1-1, “Reactor Protection System Instrumentation,” specify the formulae for the OTΔT and OPΔT reactor trip functions. There are many cycle-specific constants in the OTΔT and OPΔT functions. The LAR would relocate the values of these constants to the COLR, and specify the AVs of these functions in Notes 1 and 2. As stated above, the relocation of the values of the cycle-specific constants of these trip functions to the COLR is the adoption of the NRC-approved TSTF-339. In connection with this relocation, the LAR would also add topical report WCAP-8745-P-A, which is an approved methodology for the determination of the OTΔT and OPΔT trip functions, to TS 5.6.5. Therefore, it is consistent with TSTF-339 and GL 88-16 guidance, and is acceptable.

The OTΔT and OPΔT trip setpoints are calculated by ΔT_0 (i.e., loop specific ΔT across the core at full power) multiplied by cycle-specific constants K_1 and K_4, respectively, and other correction factors to account for variations in RCS temperature, RCS pressure, and axial offset. Since these trip setpoints vary with the plant operating conditions, the AVs of these functions are specified in the TS (Notes 1 and 2 under Table 3.3.1-1) 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 the AVs for the OTΔT and OPΔT functions of 2.8% and 1.8% of ΔT span, respectively. The OTΔT and OPΔT trip setpoints are directly proportional to the input constants K_1 and K_4, respectively. The SAL for K_1 in the SPU safety analysis is changed from 1.40 to 1.42, and the NTS for K_1 is changed from 1.20 to 1.22. The SAL for K_4 in the SPU safety analysis is changed from 1.162 to 1.164, and the NTS for K_4 from 1.1 to 1.074. Attachment 2 to NL-04-145 provides the calculation of the NTSs and AVs for K_1 and K_4, respectively, based on the OTΔT and OPΔT channel uncertainties. The calculation, based on Method 2, determines the NTS and AV for K_1 to be 1.241 and 1.2617, respectively. The licensee proposes to use conservative values of 1.22 and 1.26, respectively, compared to the existing 1.20 and 1.285, respectively. Since K_1 in the OTΔT function is a multiplier of ΔT_0, which is about 54 °F, the difference in the K_1 AV and NTS of 0.04 is converted to 2.8% of ΔT span, which is 75 °F. Also, the calculation determines the NTS and AV for K_4 to be 1.0807 and 1.1041, respectively, and the licensee proposes to use conservative values of 1.074 and 1.10, respectively, compared to the existing 1.1 and 1.154, respectively. The difference in the K_4 AV and NTS of 0.026 is converted to 1.8% of ΔT span. The staff finds that the proposed AVs for the OTΔT and OPΔT functions of not exceeding 2.8% and 1.8% of ΔT span, respectively, are acceptable.

(3) Function 7.a, Pressurizer pressure - Low:

The Pressurizer Pressure - Low trip function provides protection against DNB due to low pressure. The licensee proposed to change the AV for the pressurizer pressure - low setpoint from 1790 psig to 1900 psig. For the SPU, the SAL for this trip function is increased from 1735.3 psig to 1835.3 psig to provide margin for the hot zero power MSLB safety analysis.

Attachment 2 to NL-04-145 provides the calculation for the NTS and AV for the pressurizer pressure - Low reactor trip function. Based on the SAL value of 1835.3 psig, the calculated NTS is 1900 psig, and the AV is 1897 psig. For the purpose of providing setpoint margin and being more closely aligned with the IP2 NTS for this function, the licensee chose the values of 1930 psig and 1900 psig for the NTS and AV, respectively. Since these NTS and AV are more conservative than the calculated values, they are acceptable.

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

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

(1) Function 1.d, Pressurizer pressure - Low:

This ESFAS function initiates safety injection to provide protection against the depressurization events such as inadvertent opening of a SG relief or safety valve, steam line break, LOCAs, and SG tube rupture.

The licensee proposed to increase the AV for this ESFAS function from 1690 psig to 1710 psig. The licensee indicated that this change is not required by the SPU. The SAL is reduced slightly from 1650 psig to 1648.7 psig to ensure consistency among the various safety analyses that credit this function. Attachment 2 to NL–04-145 provides the calculations for the NTS and AV for this ESFAS function. Based on the more conservative ISA-RP67.04 Method 2 calculation, the AV is determined to be 1695.36 psig. However, since this calculated AV is below the bottom of scale of the pressurizer pressure instrument loops, which is 1700 psig, the licensee proposed the AV of 1710 psig, which is above the bottom of the instrument span. Therefore the proposed AV of 1710 psig is acceptable.

(2) 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 mitigation protection against the steamline break events. The proposed amendment would change the AV for the T_{avg} - Low interlock setpoint from 538.0 EF to 540.5 EF. The licensee indicated that this change is not required by the proposed SPU. The SAL and NTS for T_{avg} - Low remain unchanged at 535 EF and 542 EF, respectively.

Attachment 2 to the November 18, 2004, letter provides a detailed calculation of the channel uncertainties and AV for the T_{avg} - Low interlock setpoint. With the T_{avg} - Low SAL of 535.0 EF, the calculated AV is 536.4 EF based on conservative ISA-RP67.04 Method 2. Since this calculated AV is less than the bottom of the instrument span (540 EF) for this channel, the licensee proposed to the AV to be 540.5 EF, which is above the bottom of the instrument span. The staff finds the AV of 540.5 EF is conservative and acceptable.

4.6 <u>TS 3.4.1 RCS Pressure, Temperature, and Flow DNB Limits</u>

LCO 3.4.1 requires that the RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the specified limits for MODE 1 operation. The LAR would relocate the limit values of these DNB parameters currently specified in LCO 3.4.1 to the COLR by the following:

a. pressurizer pressure $ the limit specified in the COLR;
b. RCS average loop temperature # the limit specified in the COLR; and
c. RCS total flow rate $ 354,400 gpm and $the limit specified in the COLR.

Surveillance Requirements SR 3.4.1, SR 3.4.1.2, SR 3.4.1.3, and SR 3.4.1.4 are also revised accordingly.

The relocation of the limit values of the DNB parameters to the COLR is an adoption of TSTF-339 and WCAP-14483-A methodology. By relocating these DNB TS parameter values to the COLR, the COLR values would reflect the cycle-specific operating conditions and allow reactor trip setpoints to be consistent with actual operating conditions, thereby avoiding the necessity of overly conservative TS values. TSTF-339 also requires that the minimum RCS total flow limit based on a staff approved analysis be retained in the TS (LCO 3.4.1.c and SR 3.4.1.3) to assure that a lower flow rate than reviewed by the staff would not be used. 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 current TS RCS total flow rate is a limit established as the minimum measured flow (MMF), which will be relocated to the COLR. The TS will retain the corresponding value of the thermal design flow (TDF), which is the MMF minus flow measurement uncertainty. For the SPU program, the MMF limit specified in the COLR is 364,700 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 TDF of 354,400 gpm with a flow measurement uncertainty of 2.9%, as shown in Table 2.1-2 of the application report. Therefore, the revised LCO 3.4.1 and SRs are acceptable. In addition, the revision to TS Bases B3.4.1 reflects the changes to LCO 3.4.1 and SRs, and is acceptable.

4.7 TS 3.4.9 Pressurizer

LCO 3.4.9 specifies that the pressurizer shall be operable with the pressurizer water level # 58.3% during MODES 1,2 and 3 operation. 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. For the SPU, the licensee proposed to change LCO 3.4.9 and SR 3.4.9.1 by changing the pressurizer maximum water level limit from # 58.3% to # 54.3%. The TS BASES is also being changed to reflect this change. 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 59.3%. 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 59.3% during normal operation is acceptable. Accounting for the allowance for instrument error of 5.0%, the indicated pressurizer level is limited to # 54.3%. The staff finds this acceptable.

4.8 TS 3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 requires that the MSSVs shall be operable during MODES 1, 2, and 3 operation. For Condition A with one or more required MSSVs inoperable, the plant is required to reduce neutron flux trip setpoint to less than or equal to the applicable % RTP listed in TS Table 3.7.1-1, which specifies the applicable neutron flux trip setpoint as a function of the minimum number of operable MSSVs per SG. The proposed amendment would revise Table 3.7.1-1 by reducing the neutron flux trip setpoints from 60%, 41%, and 22% RTP, respectively, for 4, 3, and 2 operable MSSVs per SG, to 57%, 38%, and 20% RTP, respectively.

The purpose of the MSSVs is to provide overpressure protections for the secondary system, and also protects against overpressurization of the RCS by providing a heat sink for removal of energy from the RCS if the preferred heat sink (the condenser and circulating water system) is not available. There are five MSSVs per SG with staggered lift settings. Startup and power operation with less than five MSSVs operable for each SG is permissible if the thermal power is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by

reducing the neutron flux trip setpoint and reducing thermal power so that the energy transfer to the most limiting SG is not greater than the available relief capacity in that SG. TS BASES B3.7.1 provides an equation to calculate the neutron flux trip setpoint corresponding to the number of inoperable MSSVs per SG based on the NSSS power rating, minimum steam flow rate, and heat of vaporization for the steam. Table 3.7.1-1 is developed based on this equation and a further reduction of 9% of full scale to account for instrument uncertainty. Using the same equation, the proposed changes in Table 3.7.1-1 to reduce the neutron flux setpoint reflects the SPU of NSSS power to 3230 MWt from 3081.4 MWt. The NRC staff finds this revision acceptable.

4.9 Change to TS 5.0 Administrative Controls

4.9.1 TS 5.6.5 Core Operating Limits Report (COLR)

TS 5.6.5.a lists the specific numbers of technical specifications, of which the cycle-specific parameter limits are specified in the COLR; and 5.6.5.b lists the analytical methods used to determine the core operating limits. As a result of implementation of TSTF-339 to relocate the core limit figure 2.1-1, the OTΔT and OPΔT setpoint parameter values under Specification 3.3.1, and the DNB parameters under Specification 3.4.1, to the COLR, TS 5.6.5.a is revised to include Specifications 2.1, 3.3.1, and 3.4.1, respectively. In addition, two topical reports, which are the accepted methodology used to calculate these cycle-specific parameters are added to TS 5.6.5.b. These reports are:

- WCAP-11397-P-A, “Revised Thermal Design Procedure,” April 1989 (Specification 2.1, Safety Limits, and Specification 3.4.1, DNB parameters)

- WCAP-8745-P-A, “Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions,” September 1986 (Specification 2.1, Safety Limits)

In addition, the proposed amendment would also add the following topical report to TS 5.6.5.b:

- WCAP-10054-P-A, Addendum 2, Rev. 1, “Addendum to the Westinghouse Small Break LOCA ECCS Evaluation Model Using the NOTRUMP Code; Safety Injection into the Broken Loop and Cosi Condensation Model,” July 1997 (Specification 3.2.1 Heat Flux Hot Channel Factor (FQ(Z)).

The addition of Westinghouse topical reports (WCAPs) 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 of the added topical reports to TS 5.6.5.b have been approved by the NRC, and therefore, are acceptable.

5.0 REGULATORY COMMITMENTS

To support the proposed application for an SPU at IP3, the licensee made the following commitments as described in Sections 3.6.2.2 and 3.6.4.2 of this SE:

A. In a letter dated February 11, 2005, the licensee committed (as discussed in Commitment NL-05-020-01) to revise the TS Bases 3.4.3 to delete the reference to the PTLR and to clarify that the PT limit curves are now based on 34.0 EFPY instead of 34.7 EFPY. In addition, the licensee will clarify the basis for labeling the curves for 20 EFPY for applicability to the LTOPS arming temperature.

B. In its February 11, 2005, letter, the licensee indicated (as discussed in Commitment NL-05-020-02) that the EOL projected fluence for the IP3 RV internals will exceed the threshold of 1×10^{21} n/cm^2 (E $ 0.1 MeV). The licensee stated that it is an active participant in the EPRI MRP research initiatives on aging-related degradation of RV components. Therefore, the licensee committed to the following:

1. Continue its active participation in the EPRI MPR research initiatives regarding aging-related degradation of RV components.

2. Evaluate the EPRI recommendations resulting from this initiative and implement a RV internals degradation management program applicable to IP3.

3. Incorporate the resulting RV internals inspections into the IP3 augmented inspection plan, as appropriate.

4. Submit to NRC for review and approval, the augmented inspection plan that incorporates inspection of the IP3 RV (internals). The licensee indicated the augmented inspection plan would be submitted within 24 months after the final EPRI MRP recommendations are issued or by March 2010 (based on 5 years from the date of issuance of the IP3 SPU license amendment), whichever comes first.

The NRC staff considered the above commitments as part of its evaluation in Section 3.0 of the SE and finds the commitments appropriate for the proposed SPU. The NRC staff has conditioned the implementation of the proposed SPU on the incorporation of these commitments into the licensee's Commitment Management Program.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. The State official noted that, in an electronic mail on February 11, 2005, the State Department of Environmental Conservation (DEC) provided a summary of its review and issues about the impact from the uprate on thermal discharge to the Hudson River. The DEC wanted the NRC record for the power uprate to note the existence of these issues. However, the DEC also said that its administrative process under its proceedings for the New York State Pollutant Discharge Elimination System discharge permit for Indian Point was the appropriate forum to resolve the issues.

7.0 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 53105). 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.

8.0 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.

9.0 REFERENCES

1. NUREG-0800, “Standard Review Plan,” Revision 1, July 1981.

2. Indian Point Nuclear Generating Station Unit No. 3, Final Safety Analysis Report, Docket No. 50-286.

3. Title 10 of the *Code of Federal Regulations*, Parts 50 and 55.

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

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

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

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

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

9. Dick, George F. Jr., “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,” Letter from NRC to Oliver D. Kingsley, Exelon Nuclear, May 4, 2001.

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

11. Dick, George F. Jr., “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,” Letter from NRC to John L. Skolds, Exelon Nuclear, September 27, 2002.

12. Pham, Bo. M., “Palo Verde Nuclear Generating Station, Unit 2 (PVNGS-2) - Issuance of Amendment on Replacement of SGs and Uprated Power Operations (TAC No. MB3696),” Letter from NRC to Gregg R. Overbeck, Arizona Public Service Company, ML032720538, September 29, 2003.

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

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

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

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

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

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

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

20. Westinghouse Report WCAP-11394, “Methodology for the Analysis of the Dropped Rod Event,” R.L. Haessler, et. al., April 1987.

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

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

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

24. Letter from G. Wunder, USNRC, to Mr. James Knubel, Power Authority of the State of New York, “Issuance of Amendment for Indian Point Nuclear Generating Station Unit 3 (TAC No. M96474),” April 15, 1997.

25. Letter from F. Dacimo, Indian Point Energy Center to USNRC, “Reply to Request for Additional Information Regarding Indian Point 3 Stretch Power Uprate (TAC MC3552),” Docket No. 50-286, License No. DPR-64, Letter No. NL-04-155, dated December 15, 2004.

26. Letter from F. Dacimo, Indian Point Energy Center to USNRC, “Supporting Information for License Amendment Request Regarding Indian Point 3 Stretch Power Uprate (TAC MC3552),” Docket No. 50-286, License No. DPR-64, Letter No. NL-04-145, dated November 18, 2004.

27. USNRC Document RS-001, “Review Standard for Extended Power Uprates,” dated December 2003.

Principal Contributors:

B. Elliot	J. Collins	S. Klementowicz
J. Terrell	N. Trehan	H. Li
J. Wu	L. Lois	M. Barillas
F. Orr	W. Lyon	S. Wu
G. Hsii	D. Reddy	J. Tatum
P. Qualls	J. Hayes	R. Lobel
J. Cushing	T. Tjader	

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LIST OF ACRONYMS

AAC	Alternate AC
AFW	Auxiliary feedwater
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
CFCU	Containment Fan Cooler Unit
CFR	*Code of Federal Regulations*
COLR	Core Operating Limit Report
CRDS	Control Rod Drive System
CRDM	Control Rod Drive Mechanism
CSA	Chemical Storage Area
CSS	Containment Spray System
CST	Condensate Storage Tank
CVCS	Charging Volume and Control System
DBA	Design-Basis Accident

DBLOCA	Design-Basis Loss-of-Coolant Accident
DECL	Double-Ended Cold Leg
DNB	Departure from Nucleate Boiling
DSS	Diverse Scram System
EAB	Exclusion Area Boundary
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDY	Effective Degradation Years
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
FIV	Flow-Induced Vibration
FPP	Fire Protection Program
FSAR	Final Safety Analysis Report
FW	Feedwater
GDC	General Design Criterion
GDT	Gas Decay Tank
gpm	gallons per minute
HELB	High-Energy Line Break
HFP	Hot Full-Power
HHSI	High-Head Safety Injection
HP	High Pressure

HT	Holdup Tank
HVAC	Heating, Ventilation, and Air Conditioning
HZP	Hot Zero-Power
IASCC	Irradiation-Assisted Steam Corrosion Cracking
ICSB	Instrumentation & Control Systems Branch
IFM	Intermediate Flow Mixing
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
LHSI	Low-Head Safety Injection
LOCA	Loss-of-coolant Accident
LOL	Loss of Load
LONF	Loss of Normal Feedwater
LPZ	Low-Population Zone
LTC	Long-Term Cooling
LTOP	Low-Temperature Overpressure Protection
LWR	Light-Water Reactor
MDAFWP	Motor-Driven Auxiliary Feedwater Pump
MFW	Main Feedwater
MMF	Minimum Measured Flow
MOV	Motor-Operated Valve
MPR	Materilas Research Program
MSLB	Main Steamline Break
MSIV	Main Steam Isolation Valve
MSS	Main Steam System

MSSV	Main Steam Safety Valves
MTC	Moderator Temperature Coefficient
MVA	Megavolts-ampheres
MUR	Measurement Uncertainty Recaputure
MWe	Megawatts Electric
MWt	Megawatts Thermal
NIS	Nuclear Instrumentation System
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NR	Narrow Range
NSAL	Nuclear Safety Advisory Letters
NSSS	Nuclear Steam Supply System
NTS	Nominal Trip Setpoint
NUMARC	Nuclear Management and Resources Council
NY-ISO	New York Independent System Operator
P-T	Pressure-Temperature
PCM	Percent Millirho (^{a}K/K)
PCT	Peak Cladding Temperature
POD	Probability of Detection
PPC	Plant Process Computer
PPCS	Plant Process Computer Screen
ppm	Parts per Million
PORV	Power-Operated Relief Valve
PRV	Pressure Relief Valve
psig	Pounds per Square Inch Guage
PSV	Pressurizer Safety Valve
PTLR	Pressure-Temperature Limits Report
PTS	Pressurized Thermal Shock

PWR	Pressurized-Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RAI	Request for Additional Information
RCCA	Rod Cluster Control Assembly
RCL	Reactor Coolant Loop
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
RVI	Reactor Vessel Internals
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
SFPCS	Spent Fuel Pool Cooling System
SG	Steam Generator
SGBS	Steam Generator Blowdown System

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
SRSS	Square Root of the Sum of Squares
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
TEDE	Total Effective Dose Equivalent
TGSCC	Transgranular Stress Corrosion Cracking
TS	Technical Specification
TSTF	Technical Specification Task Force
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