June 2004

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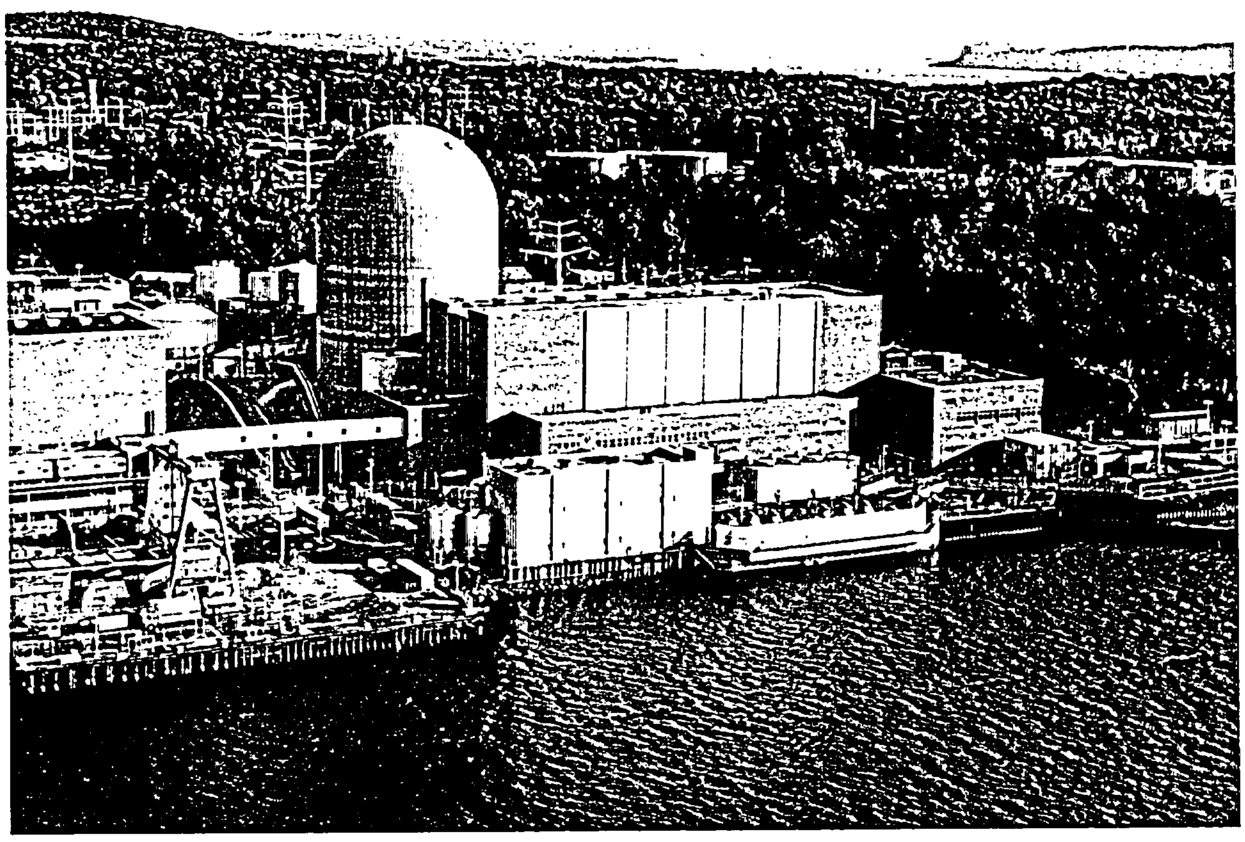
Entergy Nuclear Operations, Incorporated

Indian Point Nuclear Generating Unit No. 3



Stretch Power Uprate
License Amendment Request Package

Entergy

Entergy Nuclear Northeast
Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, NY 10511-0249
Tel 914 734 6700

Fred Dacimo
Site Vice President
Administration

June 3, 2004

Re: Indian Point Unit No. 3
Docket No. 50-286
NL-04-069

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

SUBJECT: **Proposed Changes to Technical Specifications:**
Stretch Power Uprate (4.85%) and Adoption of TSTF-339

References:

1. Technical Specification Task Force Traveler TSTF-339, Rev 2; "Relocate Technical Specification Parameters to the COLR", dated June 13, 2000.
2. NRC Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications", dated January 31, 2002.
3. Westinghouse WCAP –10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," dated January 1993.
4. NRC Review Standard (RS)-001, "Draft Review Standard for Extended Power Uprates".
5. Entergy letter to NRC, NL-04-068, "Proposed Changes to Technical Specifications Regarding Adoption of Alternate Source Term", dated June 2, 2004

Dear Sir:

Pursuant to 10 CFR 50.90, Entergy Nuclear Operations, Inc, (Entergy) hereby requests an amendment to the Operating License for Indian Point Nuclear Generating Unit No. 3 (IP3), to increase the maximum authorized reactor core power level from 3067.4 MWt to 3216 MWt.

The proposed nominal increase of 4.85% in rated thermal power is based on analyses contained in Attachment III (WCAP-16212-P). Six copies of the proprietary version and two copies of the nonproprietary version of the WCAP are being provided.

This amendment request also proposes to adopt TSTF-339 (Reference 1) regarding relocation of certain cycle-specific parameters from the Technical Specifications to the Core Operating Limits Report. The values for some of these parameters are changing as a result of the proposed power increase. The methodology used and the resulting new parameter values are described in Attachment III. In addition, Entergy is proposing changes to several Reactor Protection System and Engineered Safeguards Features System allowable values that are not affected by the proposed power increase. These allowable value changes are described in Attachment I.
The proposed changes regarding a power increase, adoption of TSTF-339, and several allowable values, have been evaluated in accordance with 10 CFR 50.91 (a)(1) using the criteria of 10 CFR 50.92 (c) and Entergy has determined that this proposed change involves no significant hazards considerations (Attachment I). The proposed change to the Facility Operating License and changes to the current Technical Specification and Bases pages are provided in Attachment II.

In accordance with 10CFR50.91, a copy of this application and the associated attachments are being submitted to the designated New York State official.

The evaluation of the proposed increase in rated thermal power has been performed following the guidance of References 2 and 3. Although Reference 4 addresses power uprate requests greater than that being requested for IP3, Entergy has reviewed the guidance of Reference 4 to identify additional information that is being provided in selected areas to support NRC evaluation and approval of this request. Safety analyses that assess hypothetical accident dose consequences at the proposed higher power level use the alternate source term (AST) methodology in accordance with 10 CFR 50.67. Therefore, NRC approval of Entergy's proposed adoption of AST (Reference 5) is required to support the proposed power increase.

Also provided, as Enclosure A, is Westinghouse authorization letter dated June 1, 2004 (CAW-04-1841), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice. As Attachment III contains information proprietary to Westinghouse Electric Company, it is supported by an affidavit signed by Westinghouse, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information that is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR 2.390 of the Commission's regulations. The non-proprietary version of the WCAP is provided as Enclosure B.

Correspondence with respect to the copyright on proprietary aspects of the items listed above or the supporting affidavit should reference CAW-04-1841 and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P. O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Entergy requests approval of the proposed amendment by March 2005 to support implementation activities and operation at the new power level following completion of the 3R13 Spring 2005

refueling outage. There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. Kevin Kingsley at 914-734-6695.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 6/3/2004.

Sincerely,

Fred R. Dacimo
Site Vice President
Indian Point Energy Center

Attachments:
I. Analysis of Proposed Technical Specification Changes
II. Proposed Technical Specification and Bases Changes (markup)
III. Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report, WCAP-16212-P, dated June 1, 2004

cc: Mr. Patrick D. Milano, Senior Project Manager
Project Directorate I,
Division of Reactor Projects I/II
U.S. Nuclear Regulatory Commission
Mail Stop O 8 C2
Washington, DC 20555

Mr. Hubert J. Miller (w/o prop. encl)
Regional Administrator
Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Resident Inspector's Office (w/o prop. encl)
Indian Point Unit 3
U.S. Nuclear Regulatory Commission
P.O. Box 337
Buchanan, NY 10511

Mr. Peter R. Smith (w/o prop. encl)
President, NYSERDA
17 Columbia Circle
Albany, NY 12203

Mr. Paul Eddy (w/o prop. encl)
New York State Dept. of Public Service
3 Empire State Plaza
Albany, NY 12223

ATTACHMENT I TO NL-04-069

ANALYSIS OF PROPOSED TECHNICAL SPECIFICATION CHANGES REGARDING INCREASE OF LICENSED THERMAL POWER, ADOPTION OF TSTF-339, AND ALLOWABLE VALUE CHANGES

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

1.0 DESCRIPTION

This is a request to amend Operating License DPR-64, Docket No. 50-286 for Indian Point Nuclear Generating Unit No. 3 (IP3) for the following items:

- Proposed increase in rated thermal power from 3067.4 MWt to 3216; an increase of approximately 4.85%,
- adopt TSTF-339 regarding relocation of technical specification parameters to the Core Operating Limits Report (COLR), and
- revision of allowable values specified for certain reactor protection system (RPS) and Engineered Safeguards Features (ESF) functions.

The proposed increase in rated thermal power has been evaluated using the guidance contained in References 1, and 2. The analyses and evaluations performed to support operation at the higher power level are described in Attachment III (WCAP 16212-P). Although the proposed power increase for IP3 is classified as a Stretch Power Uprate (SPU), Entergy also reviewed the guidance contained in Reference 3 for Extended Power Uprates (EPU). Relevant information based on this guidance, as well as NRC review comments on similar license amendment requests has been incorporated in Attachment III.

The technical specifications for IP3 currently contain the values for several parameters that are subject to change as a result of cycle-specific core reload analyses. TSTF-339 (Reference 4) addresses the relocation of these values to a COLR. This approach reduces the administrative burden associated with implementing these cycle-specific changes by using a change process governed by 10 CFR 50.59 instead of 10 CFR 50.92. New values for parameters being relocated to the COLR that are being changed as a result of the proposed power increase are described in Attachment III.

This license amendment request includes changes to several allowable values specified for RPS and ESF functions. Three of the four changes proposed for RPS functions are being made as a result of analysis assumption changes for SPU analyses. The remaining RPS function and the three proposed changes for ESF functions are not required for operation at SPU conditions. However, as part of the SPU project, Entergy evaluated the existing RPS and ESF allowable values and identified other specific functions where changes are desirable as described in the following section. In all cases where a new allowable value is proposed, the revised value incorporates sufficient conservatism to be consistent with an analysis methodology based on ISA-RP67.04 Method 2. This approach does not represent a proposed change in the current licensing basis methodology used for establishing allowable values for IP3.

2.0 PROPOSED CHANGES

Facility Operating License:

Page 3; change Rated Thermal Power from 3067.4 MWt to 3216 MWt.

Technical Specifications:

1. Rated Thermal Power (RTP), Tech Spec Section 1.1

   Current value of 3067.4 MWt is being changed to 3216 MWt consistent with the analysis and evaluation in Attachment III. There are no Bases for this Tech Spec section.

2. Reactor Core Safety Limits, Tech Spec Section 2.1.1

   TSTF-339 is being adopted for this specification. Changes consist of:

   - 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 DNB and peak fuel centerline temperature limits, respectively; and
   - Related Bases changes as specified in TSTF-339.

   The Reactor Core Safety Limits curve has been updated to reflect the proposed stretch uprate conditions. This new curve, being relocated to the COLR, is shown in Figure 6.3-1, Section 6.3 of WCAP-16212-P, provided in Attachment III.

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

   - **Function 2.a** Power range neutron flux (high):
     Change allowable value from $\leq$ 109% RTP to = 111%.

   This change is not required by the proposed increased in rated thermal power. The current safety analysis limit (SAL), 118%, is not being changed for power uprate. The current allowable value (109%) is more conservative than needed to ensure protection of the associated SAL, and is a nominal value based on original plant design specifications. The proposed new allowable value (111%) is justified by the site-specific instrument loop uncertainties and use of this value provides additional margin for as-found surveillance testing of this instrument channel. The proposed new value also includes conservatism consistent with a calculation method using ISA-RP67.04 Method 2. The additional conservatism applied for this value does not adversely affect the operating margin to the trip setpoint for this function. There are no Bases changes required for this function.

- **Function 7a** Pressurizer Pressure - Low:
  Change allowable value from $\geq$ 1790 psia to = 1900 psia

The SAL associated with this function is being increased from 1714.7 psia to 1850 psia to provide margin for the hot zero power main steam line break safety analysis at SPU conditions (Section 6.3.11 of WCAP-16212-P). The current allowable value (1790 psia) is being increased (1900 psia) to accommodate the increase in the SAL and to add additional conservatism consistent with a calculation method using ISA-RP67.04 Method 2. There are no Bases changes required for this function.

- **Function 5, Note 1** Overtemperature delta -T:
  Change allowable value as described below and adopt TSTF-339:

This function provides DNB protection for non-LOCA transients. The SAL (K1 max) associated with this function is being increased from 1.40 to 1.42 (Section 6.10 of WCAP-16212-P) to increase the channel uncertainty margin. The corresponding allowable value (K1) is being decreased from 1.285 to 1.26. In terms of delta-T span, this corresponds to a decrease from 5.8% to 2.8%. Although the SAL for this function is being increased, the allowable value is being decreased to ensure that the proposed new allowable value includes sufficient conservatism to be consistent with a calculation method using ISA-RP67.04 Method 2. Applying this additional conservatism does reduce the existing allowable value margin for this function.

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 delta-T span. The allowable value equation used for this function reflects the current licensing basis for IP3.

- **Function 6, Note 2:** Overpower delta -T:
  Change allowable value as described below and adopt TSTF-339:

This function provides fuel centerline temperature protection for non-LOCA transients. The SAL (K4 max) associated with this function is being increased from 1.162 to 1.164 (Section 6.10 of WCAP-16212-P) to increase the channel uncertainty margin. The corresponding allowable value (K4) is being decreased from 1.154 to 1.10. In terms of delta-T span, this corresponds to a decrease from 3.7% to 1.8%. Although the SAL for this function is being increased, the allowable value is being decreased to ensure that the proposed new allowable value includes sufficient conservatism to be consistent with a calculation method using ISA-RP67.04 Method 2. Applying this additional conservatism does reduce the existing allowable value margin for this function.

Note 2 is also being revised to reflect adoption of TSTF-339, which relocates parameters to the COLR and expresses the SAL in terms of delta-T span.

The allowable value equation used for this function reflects the current licensing basis for IP3.

There are no Bases changes associated with the above proposed changes to RPS allowable values.

4. Changes in Allowable Values in Table 3.3.2-1 (ESFAS Instrumentation)

- **Function 1.d** Pressurizer Pressure – Low
  Change the allowable value from ≥ 1690 psig to ≥ 1710 psig.

This change is not required by the proposed increased in rated thermal power. The SAL is being reduced slightly from 1650 psia to 1648.7 psia to ensure consistency among the various safety analyses that credit this trip function. The existing margin to the current allowable value is preserved. However, the existing allowable value is slightly below the bottom of the instrument span (1700 psig) for this channel. Although this is acceptable, because the trip setpoint implemented for this function is on span, Entergy is proposing a new allowable value that will be above the bottom of the instrument span. Sufficient additional conservatism is also being provided for this new allowable value to be consistent with a calculation method based on ISA-RP67.04 Method 2.

- **Function 1.f** High Steam Flow - Safety Injection, Coincident with Tavg Low:
  Change the allowable value from ≥ 538°F to ≥ 540.5°F.

This change is not required by the proposed increase in rated thermal power. The SAL associated with this function remains at 535°F. The proposed new allowable value will be above the bottom of the instrument span (540°F) for this channel, and sufficient additional conservatism is being provided for this allowable value to be consistent with a calculation method using ISA-RP67.04 Method 2.

- **Function 4.d** High Steam Flow - Steam Line Isolation, Coincident with Tavg – low:
  Change the allowable value from ≥ 538°F to ≥ 540.5°F.

The same description as provided for Function 1.f applies here.

There are no Bases changes associated with the above proposed changes to ESFAS allowable values.

5. RCS DNB Limits, Tech Spec Section 3.4.1

The current Tech Spec limit for Reactor Coolant System (RCS) total flow rate of 375,600 gpm is a limit established as the Minimum Measured Flow (MMF). Consistent with TSTF-339, Entergy will replace this existing Tech Spec MMF value with a corresponding value of Thermal Design Flow (TDF). TDF must be

lower than the MMF by at least the total instrument channel uncertainty on flow measurement and indication. The MMF will be relocated from Tech Specs to the COLR, and the MMF value will be lowered from 375,600 gpm to 364,700 gpm. This increases margin between the MMF used in various safety analyses (that statistically combine uncertainties) and actual flows being measured at IP3. Also, the value of the TDF used in various safety analyses is being increased from 323,600 gpm to 354,400 gpm (Table 7.2-1 of WCAP-16212-P). The increase in TDF eliminates excess margin between current MMF and TDF values (16% between 375,600 gpm and 323,600 gpm). However, 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. The SPU flow measurement uncertainty was calculated using the existing methodology described in WCAP-11397-P-A, "Revised Thermal Design Procedure", and remains at the current value of 2.9%.

In addition to the above changes regarding RCS total flow rate, the adoption of TSTF-339, also relocates the limiting values for pressurizer pressure and RCS average loop temperature to the COLR.

These proposed changes modify LCO 3.4.1 and the related Surveillances. There are no changes required for the Applicability or Actions. The associated Bases changes from TSTF-339 are also being adopted.

6. Pressurizer (water level), Tech Spec Section 3.4.9

The safety analysis initial condition assumption for pressurizer water level is being increased from 58.3% to 59.3% to bound the upper limit of T_{avg} (572°F) used in the safety analyses. Tech Spec Section 3.4.9 is also being revised to specify the limit for indicated level instead of actual level. The proposed Tech Spec limit of 54.3% includes an allowance of 5% for instrument uncertainty. This value is an input assumption uncertainty, not a statistically analyzed uncertainty. An allowance of 5% is supported by historical data from the drift monitoring program. These proposed changes modify LCO 3.4.9.a and the related Surveillance. There are no changes required for the Applicability or Actions. Related changes are also proposed for Bases Section 3.4.9.

7. Main Steam Safety Valves, Tech Spec Section 3.7.1

The proposed changes reflect new limits corresponding to the slightly higher steam flow at SPU conditions. Related changes are also proposed for Bases Section 3.7.1.

8. Containment Leakage Rate Testing Program, Tech Spec Section 5.5.15

The current peak accident containment pressure for the design basis loss of coolant accident is 38.77 psig. This section is being revised to reflect the new value of 42.0 psig for the LOCA analysis at SPU conditions (Section 6.5 of WCAP 16212-P). Also, this section is being revised to identify the containment design pressure, consistent with TSTF-52, for a plant using Option B of 10 CFR

50 Appendix J. This tech spec section currently identifies the accident pressure result for a steam line break and also specifies a minimum pressure for containment leakage testing. Both of these parameters are being deleted. The relevant accident pressure for this program is based on LOCA, not steam line break, and test pressure requirement is identified in ANSI / ANS-56.8, which is referenced in Regulatory Guide 1.163. There are no Bases for this Tech Spec section.

9. Core Operating Limits Report (COLR), Tech Spec Section 5.6.5

Section 5.6.5.a is being revised as a result of adopting TSTF-339 for the relocation of parameters to the COLR. NUREG-1431 requires that this section must reference individual specifications that address core operating limits. Three additional specifications must be added to the existing list in this section:

- 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 Departure from Nucleate Boiling (DNB) Limits

These additional specifications are being added as a result of the above proposed changes 2, 3 (for Functions 5 and 6), and 5, respectively.

Section 5.6.5.b is being revised to identify three additional references that describe analytical methods used to determine core operating limits. WCAP-11397-P-A is being added as reference 3.b, WCAP-8745-P-A is being added as reference 3.c, and WCAP-10054-P-A, Addendum 2, Revision 1, is being added as reference 3.e. The addition of references 3.b and 3.c support the adoption of TSTF-339. The addition of reference 3.e is appropriate to ensure a complete list of references. This reference applies to current analyses and SPU analyses.

There are no Bases for this Tech Spec section.

3.0 BACKGROUND

A. Stretch Power Uprate:

The Indian Point Nuclear Generating Unit No. 3 (IP3) nuclear steam supply system was designed to be capable of operation at 3216 MWt and was originally licensed (AEC Safety Evaluation Report dated September 21, 1973) for a core thermal power rating of 3025 MWt. IP3 is currently licensed for a core thermal power rating of 3067.4 MWt, based on the 1.4% measurement uncertainty recapture (MUR) power uprate approved by the NRC in License Amendment 213, issued November 26, 2002. The MUR approach allows use of improved calorimetric instrumentation for operation based on a measurement uncertainty of 0.6% instead of the 2% uncertainty assumption originally required by 10 CFR 50, Appendix K.

This amendment request proposes to increase the licensed core thermal power to 3216 MWt (nominal 4.85% increase) based on new analyses and evaluations for operation at the higher power level as described in WCAP-16212-P (Attachment III). Applicable guidance from References 1, 2, and 3 was used for this project, which is classified as a Stretch Power Uprate (SPU), based on uprate categories defined by NRC. The safety analyses with respect to 10 CFR 50, Appendix K limits have been performed based on a measurement uncertainty of 2% (3216 MWt plus 2%). Therefore, the administrative controls (required actions and completion times) established in Amendment 213 for inoperable calorimetric instrumentation (Leading Edge Flow Meters) will no longer be required for operation at the proposed new power level.

Entergy plans to implement the proposed stretch power increase in phases because of plant modifications on balance-of-plant (BOP) equipment. Phase I modifications, involving the high-pressure turbine and the moisture separator reheaters, will be accomplished during the Spring 2005 refueling outage. During Phase I, Entergy plans to initially operate at a power level less than 4 percent above the current power level until Phase II secondary side plant modifications or evaluations have been completed to support power operations up to 3216 MWt. The timing for Phase II modifications, involving the low-pressure turbines and cooling for the iso-phase bus ducts will be based on economic considerations. These remaining modifications are not limitations on the validity of the safety analyses for the proposed new core thermal power of 3216 MWt. Additional information regarding plant modifications is provided in Section 1.5 of WCAP 16212-P.

B. Adoption of TSTF-339

The IP3 Technical Specifications currently contain cycle-specific parameters that are subject to change as a result of updated analysis performed to support core reloads. Based on references 4, 5, and 6, Entergy propose to relocate the cycle-specific values for these parameters to the Core Operating Limits Report (COLR). Future changes to these values can be implemented in accordance with 10 CFR 50.59 change control processes and the administrative controls established for core reload designs. Requirements will be retained in the Technical Specifications for limiting values required to assure that safety limits are met. Technical Specifications also will identify the NRC

approved analysis methods that must be used to establish new values for the affected COLR parameters.

C. Revision of selected RPS and ESF Allowable Values

As a result of changes in safety analysis limit assumptions for three RPS trip functions, changes are needed to the corresponding tech spec allowable values for these functions. Since these allowable values are being revised, Entergy is proposing to modify four other allowable values (one RPS and three ESF) for reasons described in Section 2.0, even though these other allowable value changes are not the result of the proposed power increase.

4.0 TECHNICAL ANALYSIS

The technical analysis for the proposed increase in rated thermal power is based on applicable guidance provided in Reference 1, 2, and 3. Refer to Attachment III, WCAP 16212-P for detailed discussion of the technical analyses completed.

There is no technical analysis needed for the proposed adoption of TSTF-339. This is an administrative change, consisting of the relocation of cycle-specific parameters from the technical specifications to the Core Operating Limits Report. The existing technical analysis methodologies for calculating the values of the affected relocated parameters are not being changed. Consistent with TSTF-339, safety limit parameters and the NRC-approved methodologies for calculating cycle-specific values that satisfy the safety limits are retained in the Technical Specifications.

The methodology used to establish Tech Spec allowable values for RPS and ESF instrument channels is the same as that used to support allowable values established in prior license amendments (Reference 7). The methodology used by Entergy for IP3 conforms to Regulatory Guide 1.105, Revision 2 (Instrument Setpoints for Safety-Related Systems) and ISA-RP67.04, Part II, Draft 9. For purposes of this amendment request, Entergy has incorporated additional conservatism in the proposed new allowable values to bound an analysis method based on Method 2 of ISA-RP67.04.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

Entergy Nuclear Operations, Inc. (Entergy) has evaluated the safety significance of the proposed increase in rated thermal power, adoption of TSTF-339, and proposed changes to several allowable values for Reactor Protection System (RPS) and Engineered Safety Feature (ESF) system functions according to the criteria of 10 CFR 50.92, "Issuance of Amendment," Entergy has determined that the subject change does not involve a Significant Hazards Consideration as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No

The evaluations and analyses associated with this proposed change to core power level have demonstrated that all applicable acceptance criteria for plant systems, components, and analyses (including the Final Safety Analysis Report Chapter 14 safety analyses) will continue to be met for the proposed increase in licensed core thermal power for Indian Point 3 (IP3). The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or the operational performance of any potentially affected system, component or analysis. Therefore, the probability of an accident previously evaluated is not affected by this change. The subject increase in core thermal power will not adversely affect the ability of any safety-related system to meet its intended safety function. Further, the radiological dose evaluations in support of this power uprate effort show all acceptance criteria are met.

The relocation of cycle-specific core operating limits from the Technical Specifications to the Core Operating Limits Report (COLR), in accordance with TSTF-339, has no influence or impact on the probability or consequences of a Design Basis Accident. Adherence to the COLR and accepted methodologies for establishing COLR parameters continues to be controlled by the plant Technical Specifications. Relocation of cycle-specific values to the COLR while maintaining the limiting requirements in the Technical Specifications reduces administrative burden associated with processing license amendments for routine core reload designs.

RPS and ESF allowable values established in plant technical specifications represent acceptance criteria used by plant personnel in assessing the operability of instrumentation channels. Allowable values are not accident initiators and have no role in the probability of occurrence of an accident. Safety analyses for design basis accidents use certain assumptions (Safety Analysis Limits) regarding the actuation of RPS and ESF protective functions. The proposed allowable values are developed using a methodology that assures the accident analysis assumptions are valid and the consequences of previously analyzed accidents continue to meet established limits.

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

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No

The analyses and evaluations performed for the proposed increase in power show that all applicable acceptance criteria for plant systems, components, and analyses (including FSAR Chapter 14 safety analyses) will continue to be met for the proposed power increase in IP3 licensed core thermal power. The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or operational performance of any potentially affected system, component, or analyses. The subject increase in core thermal power will not adversely affect the ability of any safety-related system to meet its safety function. Furthermore, the conditions and changes associated with the subject increase in core thermal power will neither cause initiation of any accident, nor create any new credible limiting single failure. The power uprate does not result in changing the status of events previously deemed to be non-credible being made credible. Additionally, no new operating modes are proposed for the plant as a result of this requested change.

The relocation of cycle-specific core operating limits from the Technical Specifications to the Core Operating Limits Report (COLR), in accordance with TSTF-339, does not involve any changes to plant equipment or the way is which the plant is operated. There are no new accident initiators or causal mechanisms being introduced by this proposed change. Relocation of cycle-specific values to the COLR while maintaining the limiting requirements in the Technical Specifications reduces administrative burden associated with processing license amendments for routine core reload designs.

RPS and ESF allowable values established in plant technical specifications represent acceptance criteria used by plant personnel in assessing the operability of instrumentation channels. Revising allowable values does not involve installation of new equipment, modification to existing equipment, or a change in plant operation that could create a new or different accident scenario.

Therefore, the proposed changes described in this license amendment request will not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No

The analyses and evaluations associated with the proposed increase in power show that all applicable acceptance criteria for plant systems, components, and analyses (including FSAR Chapter 14 safety analyses) will continue to be met for this proposed increase in IP3 licensed core thermal power. The subject increase in core thermal power will not result in conditions that could adversely affect the integrity (material, design, and construction standards) or operational performance of any potentially affected system, component, or analysis. The subject power uprate will not adversely affect the ability of any safety-related system to meet its intended safety function.

Adoption of TSTF-339 allows relocation of cycle-specific parameters to the COLR, while maintaining limiting requirements in the Technical Specifications. Approved methodologies for calculating cycle-specific parameters are maintained in the Technical Specifications, and changes to the COLR are subject to the requirements and controls of 10 CFR 50.59. This assures that required margins to safety limits are maintained.

The proposed new allowable values are developed using established methodologies and incorporate additional conservatism that assures the validity of analysis limits assumed in the evaluation of hypothetical accidents.

Therefore, the proposed changes described in this license amendment request will not involve a significant reduction in the margin of safety.

5.6 Applicable Regulatory Requirements / Criteria

The proposed increase in rated thermal power and related changes to the plant Technical Specifications has been evaluated in accordance with NRC guidance provided in Regulatory Issue Summary 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002 (Reference 1). The analyses and evaluations completed to support the proposed increased in core thermal power demonstrate that acceptance criteria including those established by regulatory requirements continue to be met.

The affect of the new maximum power level on structures, systems, and components of the nuclear steam supply system and the balance-of-plant was evaluated to assure that applicable regulatory requirements and criteria are met. A description of the analyses and evaluations performed is provided in the Stretch Power Uprate Licensing Amendment Report (WCAP 16212-P) provided with this application for amendment. Table 1-2 of that report provides summary level information and shows that current design or licensing basis acceptance criteria continue to be met for operation at the uprated conditions.

The proposed relocation of various cycle-specific parameters from the technical specifications to the Core Operating Limits Report is based on TSTF-339, which has been approved by the NRC. Also, this proposed change conforms to Generic Letter 88-16 (Removal of Cycle-Specific Parameters Limits from Technical Specifications). Future changes to the COLR parameters are subject to the requirements of 10 CFR 50.59.

This license amendment request also contains proposed changes to allowable values for certain reactor protection system and engineered safety feature system instrument channels. These proposed changes are in accordance with 10 CFR 50.36 regarding limiting safety system settings. The methodology used by Entergy to establish allowable values conforms to Regulatory Guide 1.105.

Entergy has determined that the proposed change does not require any exemptions or relief from regulatory requirements, other than those technical

specification changes requested in this submittal. Additionally, this change does not affect conformance with any General Design Criteria differently than described in the FSAR.

5.7 Environmental Considerations

The proposed changes in this license amendment, including the related changes to the plant technical specifications do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 PRECEDENCE

The NRC has previously approved similar applications regarding an increase in rated thermal power for Palo Verde 2 and Kewaunee, and numerous MUR applications including Indian Point 2 and Indian Point 3. Recent NRC approvals for adoption of TSTF-339 include Millstone and Catawba.

7.0 REFERENCES

1. NRC Regulatory Issue Summary 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002.

2. Westinghouse WCAP-10263, "A Review Plan for Uprating the Licensed Power of a Pressurized Water Reactor Power Plant," dated January 1983.

3. NRC Review Standard (RS)-001, "Review Standard for Extended Power Uprates", Revision 0, December 2003.

4. Technical Specification Task Force Traveler TSTF-339, Rev 2; "Relocate Technical Specification Parameters to the COLR", dated June 13, 2000.

5. NRC Generic Letter 88-16, "Removal of Cycle-Specific Parameters from Technical Specifications," dated October 4, 1988.

6. Westinghouse WCAP-14483-A, "Generic Methodology for Expanding Core Operating Limits Report," dated January 1999.

7. NRC Safety Evaluation Report dated February 27, 2001 for IP3 License Amendment 205, Conversion to Improved Standard Technical Specifications.

ATTACHMENT II TO NL-04-069

MARKUP OF TECHNICAL SPECIFICATION AND BASES PAGES

FOR PROPOSED CHANGES REGARDING

INCREASE OF LICENSED THERMAL POWER,

ADOPTION OF TSTF-339, AND ALLOWABLE VALUE CHANGES

- Facility Operating License, page 3
- Technical Specification pages:

Page 1.1-5	Page 3.4.1-1
Page 2.0-1	Page 3.4.1-2
Page 2.0-2	Page 3.4.9-1
Page 3.3.1-13	Page 3.4.9-2
Page 3.3.1-15	Page 3.7.1-3
Page 3.3.1-19	Page 5.0-31
Page 3.3.1-20	Page 5.0-34
Page 3.3.2-8	Page 5.0-35
Page 3.3.2-11	

<u>LEGEND FOR MARKUP NOTATIONS</u>:

S = change required for proposed stretch uprate

T = change per TSTF-339 (Relocate Parameters to COLR)

X = other proposed changes not required for stretch uprate

- Technical Specification Bases pages: (for information only)

Pages B 2.1.1-2, -3, and -5
Pages B 3.4.1-1 to -3 and -5
Pages B 3.4.9-2 to -3
Page B 3.7.1-3 and -4

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

FROM IP3
FACILITY OPERATING LICENSE

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 3067.4 megawatts thermal (100% of rated power) — Amdt. 213, 11-26-2002

3216 (S)

(2) Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 220 are hereby incorporated in the License. ENO shall operate the facility in accordance with the Technical Specifications.

(3) (DELETED)

(4) (DELETED)

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, guard 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 plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Indian Point 3 Nuclear Power Plant Physical Security Plan," with revisions submitted through December 14, 1987; "Indian Point 3 Nuclear Power Plant — Amdt. 81, 6-6-88

1.1 Definitions

MODE (continued)	vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE-OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PHYSICS TESTS	PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are: a. Described in FSAR Chapter 13, Initial Tests and Operations; b. Authorized under the provisions of 10 CFR 50.59; or c. Otherwise approved by the Nuclear Regulatory Commission.
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3067.4 MWt. 3216 S

(continued)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Vessel inlet temperature, and pressurizer pressure shall not exceed the ~~SLs~~ limits specified in ~~Figure 2.1-1.~~

T

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, 5, and in MODE 6 when the reactor vessel head is on, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, 5, or 6, restore compliance within 5 minutes.

TSTF 339; Insert 1:

The COLR; and the following SLs shall not be exceeded:

T

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 curve does not provide allowable limits for normal operation.
(see LCO 3.4.1, Pressure, Temperature and Flow DNB limits, for DNB limits)

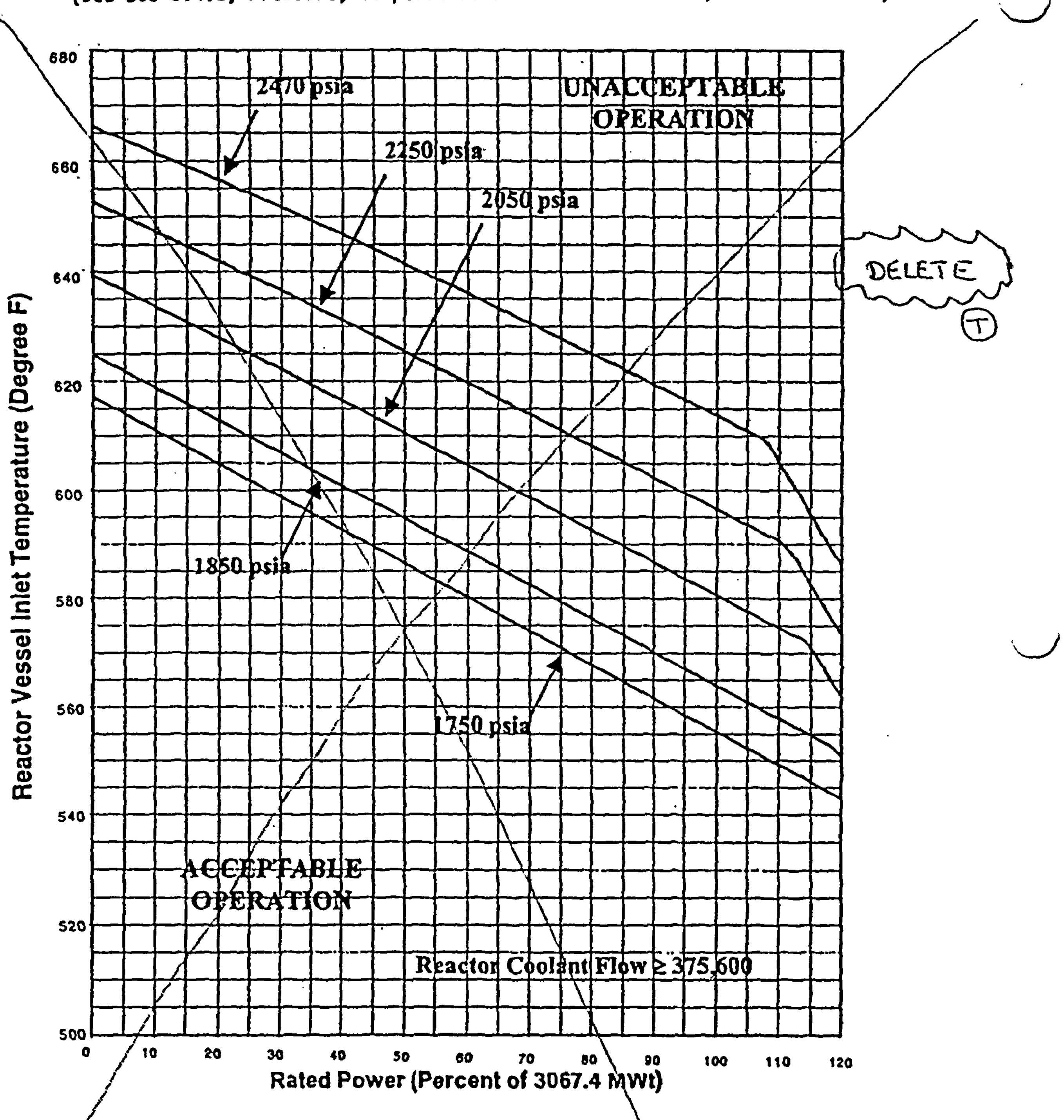


Figure 2.1-1
Rated Power (Percent of 3067.4 MWt)
100 PERCENT RATED POWER IS EQUIVALENT TO 3067.4 MWt
Pressures and temperatures do not include allowance for instrument error

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3(a), 4(a), 5(a)	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4(j)	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11	≤~~109%~~ RTP 111% X
b. Low	1(b),2	4(j)	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤25% RTP
3. Intermediate Range Neutron Flux	1(b), 2(c)	1	F	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(j) Only 3 channels required during Mode 2 Physics Tests, LCO 3.1.8

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Pressurizer Pressure					
a. Low	1(e)	4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥~~1790~~ psig 1900 S
b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤2400 psig
8. Pressurizer Water Level - High	1(e)	3	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤97%
9. Reactor Coolant Flow - Low	1(e)	3 per loop	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥90%

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

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

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o [K_1 - K_2 [(1 + \tau_1 s)/(1 + \tau_2 s)] (T_{avg} - T') + K_3 (P - P') - f(\Delta I)]$$

Where: $K_1 \leq 1.285$ $K_2 = 0.0273$ $K_3 = 0.0013$

$\tau_1 \geq 25$ seconds $\tau_2 \leq 3$ seconds

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T

ΔT_o	$\leq$	Measured full power ΔT for the channel being calibrated, °F.
T_{avg}	=	Average Temperature for the channel being calibrated, °F (input from instrument racks)
s	=	Laplace transform operator, seconds^{-1}
T'	=	Measured full power T_{avg} for the channel being calibrated, °F
P	=	Pressurizer pressure, psig (input from instrument racks)
P'	=	2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and $f(\Delta I)$ terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

τ dynamic compensation time constants

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of RTP.

$F(\Delta I)$ = a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between −15.75% and +6.9%, $f(\Delta I)=0$.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333% of RTP.

(c) or each percent that the magnitude of $q_t - q_b$ is more negative than −15.75%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000% of RTP.

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TSTF-339, Rev 2

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

(S)

Note 1: Overtemperature ΔT 2.8% [Note: IP3. CLB = 5.8%]

The Overtemperature ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than ~~[3.8]%~~ of ΔT span.

CLB

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

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T′ is the nominal T_{avg} at RTP, ≤ [~~588~~] °F.

P is the measured pressurizer pressure, psig
P′ is the nominal RCS operating pressure, ≤ [~~2235~~] psig

CLB Delete τ_3 through τ_6

[*]

$K_1 \le$ [~~1.09~~]	$K_2 \ge$ [~~0.0138~~]/°F	K_3 = [~~0.000671~~]/psig
$\tau_1 \ge$ [~~[illegible]~~] sec	$\tau_2 \le$ [~~[illegible]~~] sec	$\tau_3 \le$ [~~[illegible]~~] sec
$\tau_4 \ge$ [~~[illegible]~~] sec	$\tau_5 \le$ [~~[illegible]~~] sec	$\tau_6 \le$ [~~[illegible]~~] sec

[*]

$f_1(\Delta I)$ = ~~[illegible]~~{~~[illegible]~~ + $(q_t - q_b)$} when $q_t - q_b \le$ − [~~[illegible]~~]% RTP
0% of RTP when −[~~[illegible]~~]% RTP < $q_t - q_b \le$ [~~[illegible]~~]% RTP
~~[illegible]~~{$(q_t - q_b)$ − ~~[illegible]~~} when $q_t - q_b >$ [~~[illegible]~~]% RTP

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

The values denoted with [*] are specified in the COLR.

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

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

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o (K_4 - K_5 (dTavg/dt) - K_6(T_{avg} - T'))$$

Where:

K_4 $\geq$ 1.154

K_5 = 0 for decreasing average temperature; and
$\geq$ 0.175 sec/°F for increasing average temperature

K_6 = 0 for $T \leq T'$; and
$\geq$ 0.00134 for $T > T'$

ΔT_o $\leq$ measured full power ΔT for the channel being calibrated, °F

T_{avg} = measured average temperature for the channel being calibrated, °F
(input from instrument racks)

T' = measured full power T_{avg} for the channel being calibrated, °F
(can be set no higher than 570.3 °F)

s = Laplace transform operator, seconds

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

dTavg/dt is the rate of change of T_{avg}

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T

INSERT FOR PAGE 3.3.1-20

TSTF-339, Rev 2

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

Note 2: Overpower ΔT

1.8 % (S)

[Note: IPJ CLB = 3.7%]

The Overpower ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than ~~[3]%~~ of ΔT span.

CLB

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

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T" is the nominal T_{avg} at RTP, ≤ [~~588~~] °F.

K_4 ≤ [~~1.09~~] [*] K_5 ≥ [~~0.02~~]/°F for increasing T_{avg} [*] K_6 ≥ [~~0.00128~~]/°F when T > T"
[~~0~~]/°F for decreasing T_{avg} [~~0~~]/°F when T ≤ T"
[*] τ_1 ≥ [~~8~~] sec τ_2 ≤ [~~3~~] sec [*] τ_3 ≤ [~~2~~] sec [*]
τ_6 ≤ [~~2~~] sec τ_7 ≥ [~~10~~] sec
$f_2(\Delta I)$ = ~~0% RTP for all ΔI~~ [*]

delete τ's not used for IPJ (CLB)

The values denoted with [*] are specified in the COLR.

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

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure-Hi	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤4.80 psig
d. Pressurizer Pressure-Low	1,2,3(b)	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥~~1690~~ psig X 1710
e. High Differential Pressure Between Steam Lines	1,2,3	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	NA
f. High Steam Flow in Two Steam Lines	1,2(d),3(d)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}- Low	1,2(d),3(d)	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥~~538~~°F X 540.5

(continued)

(a) Not used

(b) Above the Pressurizer Pressure interlock.

(c) Less than or equal to turbine first stage pressure corresponding to 54% full steam flow below 20% load, and increasing linearly from 54% full steam flow at 20% load to 120% full steam flow at 100% load, and corresponding to 120% full steam flow above 100% load. Time delay for SI ≤6 seconds.

(d) Except when all MSIVs are closed.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation	1,2(d),3(d)	2 per steam line	F	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2(d),3(d)	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure (Hi-Hi)	1,2(d), 3(d)	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤24 psig
d. High Steam Flow in Two Steam Lines	1,2(d), 3(d)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}-Low	1,2(d), 3(d)	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥~~538~~°F 540.5 X
e. High Steam Flow in Two Steam Lines	1,2(d), 3(d)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with Steam Line Pressure-Low	1,2(d), 3(d)	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥500 psig

(c) Less than or equal to turbine first stage pressure corresponding to 54% full steam flow below 20% load, and increasing linearly from 54% full steam flow at 20% load to 120% full steam flow at 100% load, and corresponding to 120% full steam flow above 100% load. Time delay for SI ≤6 seconds.

(d) Except when all MSIVs are closed.

3.4 REACTOR COOLANT SYSTEM (RCS)

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

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

a. Pressurizer pressure ~~≥ 2205 psig~~ is greater than or equal to the limit specified in the COLR;

b. RCS average loop temperature ~~≤ 571.5°F~~ is less than or equal to the limit specified in the COLR; and T

c. RCS total flow rate ≥ ~~375,600~~ 354,400 S gpm and greater than or equal to the limit specified in the COLR. T

APPLICABILITY: MODE 1.

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

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

b. THERMAL POWER step > 10% RTP.

ACTIONS

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure ~~is ≥ 2205 psig~~ greater than or equal to the limit specified in the COLR (T).	12 hours
SR 3.4.1.2	Verify RCS average loop temperature ~~is ≤ 571.5°F~~ less than or equal to the limit specified in the COLR (T).	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ ~~375,600~~ 354,400 (S) gpm and greater than or equal to the limit specified in the COLR (T).	12 hours
SR 3.4.1.4	-------------------NOTE------------------- Not required to be performed until 24 hours after ≥ 90% RTP. -- Verify by precision heat balance that RCS total flow rate is ≥ ~~375,600~~ 354,400 (S) gpm and greater than or equal to the limit specified in the COLR (T).	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with: XS

a. ~~Actual~~ P pressurizer water level ≤ ~~58.3~~ 54.3% in MODES 1 and 2 or ≤ 90% in MODE 3; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW and capable of being powered from an emergency power supply.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3 with reactor trip breakers open.	6 hours
	AND	
	A.2 Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify ~~actual~~ pressurizer water level is ≤ ~~58.3~~ 54.3% in MODES 1 and 2 OR ≤ 90% in MODE 3.	12 hours (X)(S)
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	24 months

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Applicable Neutron Flux Trip Setpoint in Percent of RATED THERMAL POWER

MINIMUM NUMBER OF MSSVs PER STEAM GENERATOR REQUIRED OPERABLE	APPLICABLE Neutron Flux Trip Setpoint (% RTP)
4	≤ ~~60~~ 57
3	≤ ~~41~~ 38
2	≤ ~~22~~ 20

S

5.5 Programs and Manuals

5.5.15 Containment Leakage Rate Testing Program (continued)

cooler unit when pressurized at ≥ 1.1 Pa. This limit protects the internal recirculation pumps from flooding during the 12-month period of post accident recirculation.

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

Nothing in these Technical Specifications shall be construed to modify the testing Frequencies required by 10CFR50, Appendix J.

~~The peak calculated containment internal pressure for the design basis main steam line break, Pa, is 42.40 psig. The minimum test pressure is 42.42 psig.~~

The maximum allowable primary containment leakage rate, La, at Pa, shall be 0.1% of primary containment air weight per day.

The calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, is 42.0 psig. The containment design pressure is 47 psig.

5

5.6 Reporting Requirements

T

1. Specification 2.1, Safety Limits (SL);

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

2. ~~1.~~ Specification 3.1.1, Shutdown Margin;

3. ~~2.~~ Specification 3.1.3, Moderator Temperature Coefficient;

4. ~~3.~~ Specification 3.1.5, Shutdown Bank Insertion Limits;

5. ~~4.~~ Specification 3.1.6, Control Bank Insertion Limits;

6. ~~5.~~ Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

7. ~~6.~~ Specification 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor;

8. ~~7.~~ Specification 3.2.3, AXIAL FLUX DIFFERENCE (AFD); and

11. ~~8.~~ Specification 3.9.1, Boron Concentration.

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

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary). (Specifications 3.1.5, Shutdown Bank Insertion Limits, 3.1.6, Control Bank Insertion Limits, and 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor);

2a. WCAP-8385, "POWER DISTRIBUTION CONTROL AND LOAD FOLLOWING PROCEDURES, TOPICAL REPORT," September 1974 (W Proprietary). (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control);

2b. T. M. Anderson to K. Kneil (Chief of Core Performance Branch, NRC) January 31, 1980 -- Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch

9. Specification 3.3.1, Reactor Protection System Instrumentation;

10. Specification 3.4.1, RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits; and

T

(continued)

5.6 Reporting Requirements

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

3a. WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1), "Code Qualification Document for Best-Estimate Loss-of-Coolant-Accident Analysis," March 1998 (Westinghouse Proprietary);

3b. ~~NOT USED~~ insert 3b T

3c. ~~NOT USED~~ insert 3 c T

insert 3e X

3d. WCAP-10054-P-A, "SMALL BREAK ECCS EVALUATION MODEL USING NOTRUMP CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

3f. ~~3e.~~ WCAP-10079-P-A, "NOTRUMP NODAL TRANSIENT SMALL BREAK AND GENERAL NETWORK CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z))); and

3g. ~~3f.~~ WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor).

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

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

5.6.6 NOT USED

INSERTS FOR PAGE 3.0-35 (SECTION 5.6.5.b)

Insert 3.b:

3.b WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989 (Specification 2.1, Safety Limits (SL) and Specification 3.4.1, (RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits);

Insert 3.c:

3.c WCAP-8745-P-A, "Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip Functions," September 1986 (Specification 2.1, Safety Limits (SL));

Insert 3.e:

3.e WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break 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)));

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES

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

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

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

RCS Flow, ΔI,

The Reactor Protection System (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

appropriate operation of the RPS and steam generator safety valves.

Automatic enforcement of these reactor core SLs is provided by the following functions:

~~a. High pressurizer pressure trip;~~

~~b. Low pressurizer pressure trip;~~

~~c. Overtemperature ΔT trip;~~

~~d. Overpower ΔT trip;~~

~~e. Power Range Neutron Flux trip; and~~

~~f. Steam generator safety valves.~~

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the ΔT measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

figure

the COLR

The ~~curves~~ provided in ~~Figure 2.1-1~~ show s the loci of points of thermal power, Reactor Coolant System pressure and vessel inlet temperature for which the calculated DNBR is no less than the Safety Limit DNBR value or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

TSTF 339
INSERT 2

The calculation of these limits assumes:

1. $F_{\Delta H}^{RTP} = F_{\Delta H}^{N}$ limit at RTP specified in the COLR;

average

2. An equivalent steam generator tube plugging level of ~~up to 30% in any steam generator provided the equivalent average plugging level in all steam generators is~~ less than or equal to ~~24% (Ref. 3)~~;

10%

3. Reactor coolant system total flow rate of greater than or equal to ~~375,600~~ gpm as measured at the plant; and,

364,700

4. A reference cosine with a peak of 1.55 for axial power shape.

The figure in the COLR

~~Figure 2.1-1~~ includes an allowance for an increase in the enthalpy rise hot channel factor at reduced power based on the expression:

(continued)

TSTF-339, INSERT 2

The reactor core SLs are established to preclude violation of the following fuel design criteria:

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

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and that the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operation, normal operational transients, and AOOs.

BASES

SAFETY LIMIT VIOLATIONS	If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.
REFERENCES	1. 10 CFR 50, Appendix A. 2. FSAR, Section 7.2. ~~3. WCAP-10705, Safety Evaluation for Indian Point Unit 3 with Asymmetric Tube Plugging Among Steam Generators, October 1984.~~

B 3.4 REACTOR COOLANT SYSTEM (RCS)

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

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

INSERT A HERE

~~The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.~~

INSERT B HERE

~~The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this is the value that is compared to the acceptance criteria. A higher average temperature will cause the core to approach DNB limits.~~

INSERT C HERE

~~The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. RCS flow rate is determined by calculating the average flow rate for each loop and then calculating the sum of these average loop flow rates and this sum of the averages is compared to the acceptance criteria. A lower RCS flow will cause the core to approach DNB limits.~~

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

(continued)

BASES

BACKGROUND (continued)

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

TSTF INSERT X

LCO

This LCO specifies limits on the monitored process variables (i.e., pressurizer pressure, RCS average loop temperature, and RCS total flow rate, to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

TSTF INSERT Y

INSERT D HERE

~~The RCS total flow rate limit of 375,600 gpm allows a measurement uncertainty of 2.9% associated with the performance of Reactor coolant System Flow Calculation.~~

INSERT E HERE

~~The pressurizer pressure limit of 2205 psig includes the allowance for measurement uncertainty and instrument error. The limit on RCS average loop temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to~~

(continued)

BASES

LCO (continued)

INSERT F HERE

~~support the Vantage + fuel reloads with asymmetric tube plugging among steam generators. A maximum full power Tcold of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A Tavg of 578.3°F assures that a Tcold of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. Therefore, the LCO limit of 571.5°F for RCS average loop temperature, which is based on meeting analysis assumptions for post LOCA containment integrity, conservatively ensures that DNBR limits are met.~~

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit

~~Another set of limits on DNB related parameters~~ is provided in SL 2.1.1, "Reactor Core SLs." ~~Those limits~~ are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

The conditions which define the DNBR limit

(continued)

INSERTS FOR
Bases 3.4.1
(page 1 of 2)

Uprate Insert A

The RCS pressure limit is consistent with operation within the nominal operational envelope and controlling to 2235 psig. Pressurizer pressure indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of three control board readings. A lower pressure will cause the reactor core to approach DNB limits.

Insert B

The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope and controlling to a full power Tavg of 572.0 °F. RCS average loop temperature is assumed to be the highest indicated value of the Tavg indicators and this value is compared to the limit. The indicated limit is based on the average of three control board readings. A higher average temperature will cause the core to approach DNB limits.

Insert C

The RCS f low rate normally remains constant during an operational fuel cycle with all. pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analysis. For the 24-month surveillance, RCS flow rate is determined by performing a heat balance after each refueling at ≥ 90% RTP, calculating the flow rate for each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. For the 12-hour surveillance, RCS flow rate is determined from the average of the loop flow indications on each RCS loop, calculating the sum of these loop flow rates, and the sum is compared to the limit. The indicated limit is based on the average of two control board readings per RCS loop. A lower RCS flow rate will cause the core to approach DNB limits.

TSTF INSERT X

The pressurizer pressure limit and RCS average temperature limit specified in the COLR are based on the analytical limits used in the safety analyses. Therefore, appropriate allowances for measurement and instrument uncertainty must be included when comparing the observed value with the analytical limits.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

TSTF INSERT Y

These variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow, which is based on maximum analyzed steam generator tube plugging, is retained in the TS LCO.

INSERTS FOR
Bases 3.4.1
(page 2 of 2)

Insert D

The RCS flow rate limit of 364,700 gpm allows a measurement uncertainty of 2.9% associated with the average of two control board readings per RCS loop. A thermal design flow of 354,400 gpm and a minimum measured flow of 364,700 gpm (including measurement uncertainty) are assumed in the safety analysis. The control board loop RCS flow indications are normalized to the heat balance RCS loop flow measurements after each refueling.

Insert E

The pressurizer pressure limit of 2204 psig allows for a measurement uncertainty of 24 psig associated with the average of three control board readings. A minimum value of 2180 psig (including control and measurement uncertainties) is assumed in the safety analysis.

Insert F

The RCS average loop temperature limit of 576.3 deg-F allows for a measurement uncertainty of 3.2 deg-F associated with the average of three control board readings. A maximum full power Tavg of 579.5 deg-F (including control deadband and measurement uncertainties) is assumed in the safety analysis. 579.5 deg-F in the safety analysis corresponds to a maximum Tavg control value of 572.0 deg-F.

BASES

BACKGROUND (continued)

margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480V vital buses as follows: bus 2A (DG 31) supports 485 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

APPLICABLE SAFETY ANALYSES

For events that result in pressurizer insurge (e.g., loss of normal feedwater, loss of offsite power and loss of load/turbine trip), the analyses assume that the limiting value for the highest initial pressurizer level is 59.3%. This analytical limit is based on the pressurizer program level of 50.8% at a full power Tavg 572°F plus a conservative 8.5% of span. For other events, the nominal value of pressurizer level is assumed because the effect of the initial pressurizer level on the results is small.

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. ~~The required pressurizer level of ≤ 50.3% is the analytical limit used as an initial condition in the accident analysis. An additional margin should be allowed for instrument error.~~

that are examined for pressurizer filling, the loss of normal feedwater and loss of offsite power analyses, assume

Safety analyses presented in the FSAR (Ref. 1) ~~do not take credit for~~ pressurizer heater operation~~; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.~~

, as operation of the heaters makes the transient results more limiting by contributing to the thermal expansion of the water in the pressurizer.

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36. ~~Although the heaters are not specifically used in accident analysis, the~~ The need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

(continued)

BASES (continued)

LCO

INSERT G HERE

~~The LCO requirement for the pressurizer to be OPERABLE with water level less than or equal to 58.3%, ensures that a steam bubble exists. The required pressurizer level of ≤ 58.3% is the analytical limit used as an initial condition in the accident analysis. An additional margin of approximately 7% should be allowed for instrument error (i.e., the indicated level should not exceed 51.3%).~~

Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. Each of the 2 groups of pressurizer heaters should be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW is sufficient to maintain pressure and is dependent on the heat losses.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an

(continued)

Insert G (page B 3.4.9-3)

The pressurizer water level limit is consistent within the nominal operational envelope and controlling to 50.8% level span at a full power Tavg of 572.0°F. The pressurizer water level must be ≤ 54.3% for the pressurizer to be OPERABLE and will ensure that a steam bubble exists. Pressurizer water level indications are averaged to provide a value for comparison to the limit. The indicated limit is based on the average of two control board readings, and allows for a measurement uncertainty of 5%.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat) in Mwt (i.e. 3230 Mwt);

Deleted: 3081.4

K = Conversion factor, 947.82 (Btu/sec)/Mwt;

ws = Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure, including tolerance and accumulation, as appropriate, in lb/sec. (ws = 150 + 228.61 * (4 - V) lb/sec, where V = Number of inoperable safety valves in the steam line of the most limiting steam generator).

h_{fg} = Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm (i.e.,608.5 Btu/lbm).

N = Number of loops in plant (i.e., 4).

The calculated reactor trip setpoint is further reduced by 9% of full scale to account for instrument uncertainty and then rounded down.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% RTP. An MSSV will be considered inoperable if it fails to open on demand. The LCO requires that five MSSVs be OPERABLE in compliance with Reference 2. This is because operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements). These limitations are according to Table 3.7.1-1 in the accompanying LCO, and Required Action A.1.

Deleted: 100.6

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced.

(continued)

BASES

LCO (continued)

The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

The lift settings, according to Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB.

APPLICABILITY

In MODE 1 above ~~23%~~ 20% RTP, the number of MSSVs per steam generator required to be OPERABLE must be according to Table 3.7.1-1 in the accompanying LCO. Below ~~23%~~ 20% RTP in MODES 1, 2, and 3, only two MSSVs per steam generator are required to be OPERABLE.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

Startup and power operation with up to three of the five MSSVs associated with each steam generator inoperable is permissible if the maximum allowed power level is below the heat removing capability of the operable MSSVs. Therefore, startup and power operation with inoperable main steam line safety valves is allowable if the neutron flux trip setpoints are restricted within the limits specified in Table 3.7.1-1. This ensures that reactor power level is limited so that the heat input from the primary side will not exceed the heat removing capability of the OPERABLE MSSVs of the most limiting steam generator.

(continued)

ATTACHMENT III TO NL-04-069

WCAP-16212-P (Proprietary)

Indian Point Nuclear Generating Unit No. 3
Stretch Power Uprate
NSSS and BOP Licensing Report

NOTE: Attachment III report is not included with packages for non-proprietary distribution. WCAP-16212-NP (Non-Proprietary) is provided in lieu of Attachment III

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

ENCLOSURES TO NL-04-069

A. Westinghouse authorization letter dated June 1, 2004 (CAW-04-1841), with the accompanying affidavit, Proprietary Information Notice, and Copyright Notice

B. WCAP-16212-NP, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report," dated May 2004. (Non-Proprietary)

Enclosure B is included in lieu of Attachment III for packages issued to non-proprietary distribution.

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 3
DOCKET NO. 50-286

Westinghouse

Westinghouse Electric Company
Nuclear Services
P.O. Box 355
Pittsburgh, Pennsylvania 15230-0355
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555-0001

Direct tel: (412) 374-4643
Direct fax: (412) 374-4011
e-mail: greshaja@westinghouse.com

Our ref: CAW-04-1841

June 1, 2004

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: WCAP-16212-P, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-04-1841 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying affidavit by Entergy Nuclear Operations.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse affidavit should reference this letter, CAW-04-1841, and should be addressed to J. A. Gresham, Manager, Regulatory Compliance and Plant Licensing, Westinghouse Electric Company LLC, P.O. Box 355, Pittsburgh, Pennsylvania 15230-0355.

Very truly yours,

J. A. Gresham

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Enclosures

cc: W. Macon
E. Peyton

CAW-04-1841

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF ALLEGHENY:

Before me, the undersigned authority, personally appeared J. A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

PATRICIA L. CROWN COMMONWEALTH OF PENNSYLVANIA NOTARY PUBLIC

J. A. Gresham

J. A. Gresham, Manager
Regulatory Compliance and Plant Licensing

Sworn to and subscribed
before me this 1st day
of June, 2004

Patricia L. Crown
Notary Public

Notarial Seal
Patricia L. Crown, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Feb. 7, 2005
Member, Pennsylvania Association of Notaries

(1) I am Manager, Regulatory Compliance and Plant Licensing, in Nuclear Services, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse "Application for Withholding" accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iii) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(iv) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(v) The proprietary information sought to be withheld in this submittal is that which is appropriately marked in WCAP-16212-P, "Indian Point Nuclear Generating Unit No. 3 Stretch Power Uprate NSSS and BOP Licensing Report" (Proprietary) dated June 2004, being transmitted by the Entergy Nuclear Northeast letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted for use by Westinghouse for the Indian Point Nuclear Generating Unit No. 3 is expected to be applicable for other licensee submittals in response to certain NRC requirements for justification of Stretch Power Uprate License Amendment Request.

This information is part of that which will enable Westinghouse to:

(a) Provide information in support of plant power uprate licensing submittals.

(b) Provide plant specific calculations.

(c) Provide licensing documentation support for customer submittals.

Further this information has substantial commercial value as follows:

(a) Westinghouse plans to sell the use of similar information to its customers for purposes of meeting NRC requirements for licensing documentation associated with power uprate licensing submittals.

(b) Westinghouse can sell support and defense of the technology to its customers in the licensing process.

(c) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar calculations, evaluations, analyses and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

Westinghouse Non-Proprietary Class 3

WCAP-16212-NP June 2004

Indian Point Nuclear Generating Unit No. 3

Stretch Power Uprate NSSS and BOP Licensing Report

Westinghouse Non-Proprietary Class 3

WCAP-16212-NP

Indian Point Nuclear Generating Unit No. 3

Stretch Power Uprate NSSS and BOP Licensing Report

J. R. Stukus
Westinghouse Nuclear Services

T. F. Timmons
Westinghouse Nuclear Services

T. J. Gerlowski
Westinghouse Nuclear Services

P. Cafarella
Stone and Webster Engineering Corporation

M. Scanlon
Stone and Webster Engineering Corporation

June 2004

Westinghouse Electric Company LLC

P.O. Box 355

Pittsburgh, PA 15230-0355

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LIST OF ACRONYMS

1-D	one-dimensional
2-D	two-dimensional
3-D	three-dimensional
AAC	alternate AC
ACI	American Concrete Institute
AEC	Atomic Energy Commission
AFW	auxiliary feedwater
AFWS	Auxiliary Feedwater System
AISC	American Institute of Steel Construction
ALARA	as-low-as-is-reasonably-achievable
AMSAC	ATWS mitigating system actuation circuitry
ANC	Advanced Nodal Code
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOR	Analysis of Record
AOV	air-operated valve
ART	adjusted reference temperature
ARV	atmospheric relief valve
ASD	after shutdown
ASME	American Society of Mechanical Engineers
ASSS	Alternate Safe Shutdown System
AST	alternative source term
ATWS	anticipated transient without scram
AV	allowable value
AVB	anti-vibration bar
B&PV	boiler and pressure vessel
BELBLOCA	best-estimate large-break loss-of-coolant accident
BFRV	bypass feedwater regulator valve
bhp	brake horsepower

LIST OF ACRONYMS (Cont.)

BMI	bottom-mounted instrumentation
BOC	beginning of cycle
BOL	beginning of life
BOP	balance of plant
BOT	break opening time
BRS	Boron Recycle System
Btu	British thermal unit
C&FS	Condensate and Feedwater System
CAOC	constant axial offset control
CBP	condensate booster pump
CCR	central control room
CCW	component cooling water
CCWS	Component Cooling Water System
CDF	core damage frequency
CEDE	committed effective dose equivalent
CFD	computational fluid dynamics
CFR	Code of Federal Regulations
CIV	containment isolation valve
CLH	capped latch housing
CLOF	complete-loss-of-flow
CLOF-UF	complete-loss-of-flow under frequency
CN	calculation note
COLR	*Core Operating Limit Report*
COMS	Cold Overpressure Mitigation System
CP	condensate pump
CPS	Condensate Polishing System
CR	containment recirculation
CRDM	control rod drive mechanism
CS	containment spray

LIST OF ACRONYMS (Cont.)

CSA	channel statistical allowance
CSS	Containment Spray System
CST	condensate storage tank
CU	channel uncertainty
CUF	cumulative usage factor
Cv	valve flow coefficient
CVCS	Chemical and Volume Control System
CW	circulating water
CWIT	circulating water inlet temperature
CWS	Circulating Water System
DBA	design basis accident
DBE	design basis earthquake
DCF	dose conversion factor
DCP	design change package
DDE	deep dose equivalent
DE	dose equivalent
DECL	double-ended cold leg
DEHL	double-ended hot leg
DEPS	double-ended pump suction
DER	double-ended rupture
DF	decontamination factor
DG	diesel generator
DGV	degraded grid voltage
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOR	Division of Operating Reactors
dpa	displacement of atom
DSS	Diverse Scram System

LIST OF ACRONYMS (Cont.)

DW	Direct Work Item
EAB	exclusion area boundary
EBOP	emergency bearing oil pump
ECCS	Emergency Core Cooling System
EDE	effective dose equivalent
EDG	emergency diesel generator
EFPY	effective full-power year
EM	evaluation model
EOC	end of cycle
EOL	end of life
EOP	Emergency Operating Procedure
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPT	electrical penetration tunnel
EPU	extended power uprate
EQ	environmental qualification
ERG	Emergency Response Guideline
ES	extraction steam
ESF	engineered safety feature
ESFAS	Engineered Safety Feature Actuation System
ESOP	emergency seal oil pump
ESS	Extraction Steam System
ET	electric tunnel
ETAP	Electrical Transient Analyzer Program
FAC	final acceptance criteria
FAC	flow-accelerated corrosion
FACP	Flow Accelerated Corrosion Program
FCEP	Fuel Criteria Evaluation Process
FCU	fan cooling unit

FCV	feedwater control valve
FDB	flow distribution baffle
FES	Final Evaluation Statement
FHA	fuel-handling accident
FHB	Fuel-Handling Building
FIV	feedwater isolation valve
FIV	flow-induced vibration
FLB	feedwater line break
F_N	Froude Number
FOA	fans, oil, and air
FPPP	Fire Protection Program Plan
FQ	peaking factor
FRV	feedwater regulator valve
FSAR	Final Safety Analysis Report
FU	fuel upgrade
FWH	feedwater heater
FWI	feedwater isolation
FWIV	feedwater isolation valve
FWS	Feedwater System
GDC	General Design Criteria
GDT	gas decay tank
GI	Generic Issue
GL	Generic Letter
GSI	Generic Safety Issue
GSS	Gland Steam System
GWDS	Gaseous Waste Disposal System
HD	heater drain pump
HEI	Heat Exchange Institute, Inc.
HELB	high-energy line break

LIST OF ACRONYMS (Cont.)

HFF	hydraulic forcing function
HFP	hot full power
HHSI	high-head safety injection
HHSIS	High-Head Safety Injection System
HLSO	hot-leg switchover
hp	horsepower
HP	high pressure
HT	holdup tank
HVAC	heating, ventilation, and air conditioning
HZP	hot zero power
I&C	instrumentation and control
ICH	in-core hold
ID	inside diameter
IFBA	integral fuel burnable absorber
IFM	intermediate flow mixing
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
IP1	Indian Point Unit 1
IP2	Indian Point Unit 2
IP3	Indian Point Unit 3
IPB	Iso-Phase bus
ISI	in-service inspection
ISLH	in-service leak and hydrostatic
ISONE	Independent System Operator New England
IST	in-service testing
ITS	Improved Technical Specifications
K_{eff}	effective multiplication factor
K_I	stress intensity factor
K_{IC}	critical value of K_I, or fracture toughness

LIST OF ACRONYMS (Cont.)

K_{IR}	reference stress intensity factor
LAR	Licensing Amendment Request
LBB	leak-before-break
LBLOCA	large-break loss-of-coolant accident
LCV	level control valve
LEFM	linear elastic fracture mechanics
LERF	large early release frequency
LHF	LOCA hydraulic force
LHSI	low-head safety injection
LHSIS	Low-Head Safety Injection System
LOAC	loss-of-AC power
LOCA	loss-of-coolant accident
LOCA RV/RI	LOCA reactor vessel/reactor internal
LOL	loss-of-load
LONF	loss of normal feedwater
LOOP	loss-of-offsite power
LP	low pressure
LPP	low-pressurizer pressure
LPZ	low-population zone
LTOP	low-pressure overpressure protection
LTOPS	Low-Pressure Overpressure Protection System
LWPS	Liquid Waste Processing System
LWR	light water reactor
M&E	mass and energy
MA	mill-annealed
MBFP	main boiler feed pump
m/c	measurement/calculation
MCO	moisture carryover

LIST OF ACRONYMS (Cont.)

MDAFWP	motor-driven auxiliary feedwater pump
MFIV	main feedwater isolation valve
MFP	main feedwater pump
MFWV	main feedwater valve
MMF	minimum measured flow
MOC	middle of cycle
MOL	middle of life
MOP	moisture pre-separator
MOV	motor-operated valve
MS	main steam
MSIV	main steam isolation valve
MSLB	main steamline break
MSR	moisture separator reheater
MSS	Main Steam System
MSSV	main steam safety valve
MT	main transformer
MTC	moderator temperature coefficient
MTU	metric ton unit
MUR	measurement uncertainty recapture
NDE	nondestructive examination
NEC	National Electric Code
NEMA	National Electric Manufacturer's Association
NIS	Nuclear Instrumentation System
NPCC	Northeast Power Coordinating Council
NPSH	net positive suction head
NPSHA	net positive suction head, actual
NPSHR	net positive suction head, required
NR	narrow range
NRC	Nuclear Regulatory Commission

LIST OF ACRONYMS (Cont.)

NRS	narrow range span
NSSS	Nuclear Steam Supply System
NTS	nominal trip setpoint
NUMARC	Nuclear Management and Resource Council
NUPPSCO	Nuclear Power Plant Standards Committee
NUS	Nuclear Utilities Service
NYISO	New York Independent System Operator
NYPA	New York Power Authority
OBE	operating basis earthquake
OD	outside diameter
ODSCC	outer diameter stress corrosion cracking
OEM	Original Equipment Manufacturer
OFA	optimized fuel assembly
OL	Operating License
OPS	Overpressure Protection System
OPΔT	overpower ΔT
OTΔT	overtemperature ΔT
P&I	proportional and integral
PAB	Primary Auxiliary Building
PAOT	post accident operability time
PCT	peak clad temperature
PCWG	Performance Capability Working Group
PICS	Plant Integrated Computer System
PJM	Pennsylvania-Jersey-Maryland
PLOF	partial-loss-of-flow
PICS	Plant Integrated Computer System
PORV	power-operated relief valve
POV	power-operated valve

LIST OF ACRONYMS (Cont.)

PRT	pressurizer relief tank
PSA	Probabilistic Safety Assessment
PSE&G	Public Service Electric & Gas
PSS	Primary Sampling System
PSV	pressurizer safety valve
P-T	pressure-temperature
PTS	pressurized thermal shock
PU	power uprate
PVC	polyvinyl chloride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
PWST	primary water storage tank
PZR	pressurizer
QA	Quality Assurance
RAI	Request for Additional Information
RAT	reserve auxiliary transformer
RCCA	rod control cluster assembly
RCDT	reactor coolant drain tank
RCFC	reactor containment fan cooler
RCL	reactor coolant loop
RCP	reactor coolant pump
RCS	Reactor Coolant System
RCSES	Reactor Coolant System equipment support
RG	Regulatory Guide
RHR	residual heat removal
RHRS	Residual Heat Removal System
RI	reactor internals
RPS	Reactor Protection System
RPV	reactor pressure vessel

LIST OF ACRONYMS (Cont.)

RSAC	Reload Safety Analysis Checklist
RSE	Reload Safety Evaluation
RSG	replacement steam generator
RTD	resistance temperature detector
RTDP	Revised Thermal Design Procedure
RT_{NDT}	reference temperature nil ductility temperature
RTP	rated thermal power
RT_{PTS}	reference temperature-pressurized thermal shock
RTS	Reactor Trip System
RV	reactor vessel
RVHP	reactor vessel head penetration
RWST	refueling water storage tank
S&W	Stone and Webster
SAL	safety analysis limit
SAT	station auxiliary transformer
SB	site boundary
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SBV	Shield Building ventilation
SCC	stress corrosion cracking
SCRUP	special crossunder pipe separator
SENY	Southeast New York
SER	*Safety Evaluation Report*
SFP	spent fuel pit
SFPCS	Spent Fuel Pit Cooling System
SG	steam generator
SGBS	Steam Generator Blowdown System
SGR	steam generator replacement
SGTP	steam generator tube plugging

LIST OF ACRONYMS (Cont.)

SGTR	steam generator tube rupture
SI	safety injection
SIS	Safety Injection System
SJAE	steam jet air ejector
SLI	steamline isolation
SP	separator parameter
SPDES	State Pollutant Discharge Elimination System
SPU	stretch power uprate
SRIS	System Reliability Impact Study
SRP	Standard Review Plan
SRSS	square root sum of the squares
SRST	spent resin storage tank
SSE	safe shutdown earthquake
STDP	Standard Thermal Design Procedure
SW	service water
SWGR	switchgear room
SWPC	Siemens-Westinghouse Power Corporation
SWS	Service Water System
TA	total allowance
T_{avg}	average temperature
T_{cold}	cold leg temperature
TDAFWP	turbine-driven auxiliary feedwater pump
TDF	thermal design flow
TDH	total discharge head
TEDE	total effective dose equivalent
TGSCC	transgranular stress corrosion cracking
T_{hot}	hot leg temperature

LIST OF ACRONYMS (Cont.)

TID	Technical Information Document
TMI	Three Mile Island
t_{min}	tube wall thickness minimum
t_{nom}	tube wall thickness nominal
TOI	Temporary Operation Instruction
T_{ref}	reference temperature
T_{sat}	water at pressurizer temperature or saturation temperature
TSP	trisodium phosphate
TSP	tube support plate
T_{steam}	steam temperature
UAT	unit auxiliary transformer
UFSAR	*Updated Final Safety Analysis Report*
UHS	ultimate heat sink
UHTR	upper head temperature reduction
USE	upper shelf energy
UT	ultrasonic testing
WBS	Work Breakdown Structure
VCT	volume control tank
WCAP	Westinghouse Commercial Atomic Power

1.0 INTRODUCTION

1.1 Background

Entergy Nuclear Operations, Inc. is requesting that the NRC review and approve an increase of approximately 4.85 percent in the licensed rated core thermal power from 3067.4 to 3216 MWt.

The stretch power uprate (SPU) is planned to occur over different refueling outages because of modifications that have to be performed to achieve 3216 MWt. Entergy plans to initially operate at a power level less than 4 percent above the current power level until secondary side plant modifications or evaluations have been completed to support power operations up to 3216 MWt.

Phase 1 will be accomplished following the upcoming refueling outage, with modifications to the high-pressure (HP) turbine and moisture separator reheaters to a power level less than 4 percent above the current power level. This power level is based on current design limitations of the low-pressure (LP) turbine.

Phase 2 of the uprate will be based on future economic decisions relating to modifications to the LP turbines and cooling for the generator and iso-phase bus (IPB) ducts. Section 1.5 of this document contains the potential list of modifications that could be required to achieve 3216 MWt.

This report summarizes the various analyses and evaluations of the potential effects of the SPU on plant systems, components, and analyses.

1.1.1 Uprate Power Level

IP3 was originally licensed to operate with a rated core thermal power of 3025 MWt. The current IP3 operating license issued by the NRC is for a rated reactor core power of 3067.4 MWt, based on the recently approved 1.4-percent measurement uncertainty recapture (MUR) uprate (Reference 1).

The IP3 engineered safety features (ESFs) were designed to accommodate the conditions associated with a rated core thermal power of 3216.5 MWt, which is above the original licensed core thermal power (3025 MWt) and above the current licensed core thermal power (3067.4 MWt).

Continuing industry improvements in analytical techniques, instrument measurement accuracies, plant thermal performance, and fuel and core designs have resulted in increased margins between the safety analyses results and the licensing limits. These industry

improvements, combined with the margins in the as-designed equipment, system, and component capabilities, and margins in the current safety analyses, provide IP3 with the opportunity to increase the current licensed core thermal power rating of 3067.4 to 3216 MWt (an increase of 4.85 percent) with no significant increase in the hazards presented by the plant as currently licensed by the NRC.

This was confirmed prior to full initiation of the SPU when Entergy Nuclear Operations, Incorporated (Entergy) completed a feasibility and scoping study with the support of Westinghouse Electric Company LLC (Nuclear Steam Supply System), Stone & Webster (balance of plant), and the Siemens-Westinghouse Power Corporation (high-pressure turbine).

1.1.2 References

1. Entergy Nuclear Operations, Incorporated, *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, May 2002. (Approved in License Amendment 213 on November 26, 2002.)

1.2 Licensing Approach

1.2.1 Introduction

The NRC defines three categories of power uprates:

- Measurement uncertainty recapture (MUR) power uprates
- Stretch power uprates (SPUs)
- Extended power uprates (EPUs)

MUR power uprates are less than 2 percent. SPUs are typically up to 7 percent, and EPUs are greater than SPUs, and have been submitted to the NRC for increases as high as 20 percent.

The IP3 SPU represents a licensed core power level increase of 4.85 percent. This level of uprate is more than what is typically considered for an MUR power uprate (NRC guidance in Regulatory Issue Summary [RIS] 2002-03, *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, January 31, 2002 [Reference 1]), but is less than the 7-percent threshold defined by the NRC as the lower bound for EPU according to RS-001, (Reference 2) NRC guidance for review of EPUs. The NRC has not yet issued guidance pertaining to SPU programs. Therefore, this application incorporates appropriate elements of both the NRC MUR and EPU guidance documents.

While RIS 2002-03 (Reference 1) (MUR guidance) does not specifically apply to the 4.85-percent IP3 SPU, this report has been structured to clearly distinguish affected and unaffected plant systems, components, and analyses. Affected systems, components, and safety analyses are those having current design and licensing bases analyses and calculations that do not bound the potential effects of the SPU. Unaffected systems, components, and safety analyses are those having current design and licensing bases analyses and calculations that bound the potential effects of the SPU. This report also identifies whether affected plant systems, components, and analyses were addressed through analysis or engineering evaluation.

While RS-001 (Reference 2) (EPU guidance) does not explicitly apply to the 4.85-percent IP3 SPU, significant detail has been provided for the analyses and evaluations of affected systems, components, and analyses. In particular, more detail has been provided for the safety analyses since many of these analyses have been revised to address the increased power level, or revised to amend inputs and parameters to provide additional margin for operations. Also, this report is based upon the consideration of the EPU guidance regarding the scope of NRC's review, and information expected in a power uprate application as discussed in the RS-001 (Reference 2).

The subject matter and detail of this report exceeds that corresponding to the MUR guidance for power uprate. The full scope of this project was jointly established by Entergy, Westinghouse, Stone & Webster (S&W), and Siemens-Westinghouse Power Corporation (SWPC) as part of an extensive planning effort. That planning effort included the development of a comprehensive Work Breakdown Structure (WBS). The planning team used experience from previous uprate projects to support the development of the WBS. The specific requirements needed to fulfill each work package within that WBS were also defined and assigned to ensure that all necessary work was accomplished. Furthermore, the SPU also incorporated responses to previous NRC Requests for Additional Information (RAIs) that have been issued for other previous uprates. To aid in the review of this Licensing Report, Table 1-1 provides a cross-reference of sections of this report with topical review areas for the various NRC review branches. As an additional aid in reviews, Table 1-2 provides information regarding:

- Whether Licensing Report sections were affected or unaffected by the SPU (according to the definitions of Reference 1).
- The method of SPU reconciliation (whether the SPU revised the analysis of record or evaluated the SPU effect on the analysis of record).
- Whether there was a change to the current design or licensing basis acceptance criteria.

Furthermore, Westinghouse has addressed the potential effects of the SPU on Nuclear Steam Supply System (NSSS) systems, components, and safety analyses consistent with the Westinghouse methodology established in WCAP-10263 (Reference 3). Since its submittal to the NRC, the WCAP-10263 methodology has been successfully used as the basis for power uprate projects for over 30 pressurized water reactor (PWR) units.

The methodology in WCAP-10263 (Reference 3) establishes the general approach and criteria for uprate projects, including the broad categories that must be addressed, such as NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel, as well as the interfaces between the NSSS and balance-of-plant (BOP) systems. The methodology includes the use of well-defined analysis input assumptions and parameter values, use of currently approved analytical techniques, and use of currently applicable licensing criteria and standards. A comprehensive engineering review program consistent with the WCAP-10263 (Reference 3) methodology has been performed for IP3 to evaluate the increase in the licensed core power from 3067.4 to 3216 MWt.

1.2.2 References

1. NRC RIS-2002-03, *Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications*, January 31, 2002.

2. NRC RS-001 (Draft), *Review Standard for Extended Power Uprates*, December 2002.

3. WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant*, January 1983.

1.3 Scope Summary and Application Report Structure

In support of the IP3 SPU, the following principal organizations have performed major analyses and evaluations to demonstrate that IP3 will remain in compliance with applicable licensing criteria and requirements at the SPU power level.

- Entergy Nuclear Operations, Incorporated (Entergy)
- Westinghouse Electric Company LLC (Westinghouse)
- Stone & Webster (S&W)
- Siemens-Westinghouse Power Corporation (SWPC)

The scope of the above organizations is discussed in the following subsections.

1.3.1 Entergy Nuclear Operations, Incorporated

Entergy Nuclear Operations, Incorporated (Entergy) has extensive experience in owning, managing, and operating nuclear power plants. Entergy has site resources located at the 10 units that it operates and corporate resources located at headquarters in Jackson, Mississippi, and at ENN offices in White Plains, New York. These resources provide significant experience, talent, and oversight that have been applied to ensure that the IP3 SPU meets all NRC requirements. The Entergy SPU Team members have more than 200 years of operations, design, licensing, and management experience at nuclear plants. Two members of the team have been licensed as Senior Reactor Operators at Indian Point.

As licensee and operator, Entergy has the overall technical, contractual, and commercial oversight and decision-making responsibility for the IP3 SPU. Entergy is responsible for oversight of the program, and has monitored the performance of its subcontractors and support organizations regarding scope of responsibility, quality of performance, compliance with schedules, and communication among team member organizations. Entergy controlled the progress of the overall project with input from each of the team member organizations. Entergy reviewed and authorized revisions to the project scope and schedule and managed the commercial implications of those changes. Entergy was responsible for contract management with regard to performance of its contractors. In select cases, Entergy provided supporting analysis based on best engineering methods and practices available for use at the time. On technical matters, Entergy consulted with its subcontractors, but had the final authority related to IP3 decisions.

Entergy reviewed results of the analyses, evaluations, and the design of planned plant modifications, and has developed a plan to incorporate them into the IP3 design and licensing basis.

1.3.2 Westinghouse Electric Company LLC

Westinghouse has extensive experience in the design and analysis of NSSS systems, including analyses and evaluations for uprates. Westinghouse has performed all of the accident and transient analyses for IP3 since the initial licensing of the plant in 1975. As the IP3 Original Equipment Manufacturer (OEM) NSSS designer and supplier, Westinghouse has extensive historical design documentation and engineering experience applicable to IP3. Westinghouse worked closely with Entergy in the recent past on the Measurement Uncertainty Recapture (MUR) Uprate Program. Because of this, many of the engineers assigned to the uprate project are familiar with the IP3 design and analyses and have worked closely with Entergy plant personnel. The Westinghouse IP3 SPU Team members have recent experience in managing power uprate projects as well as significant engineering and licensing experience applicable to IP3.

Westinghouse scope includes all NSSS-related analyses and evaluations, including the NSSS performance parameters, NSSS design transients, NSSS systems and components, design basis accidents (DBAs) (except for main steamline break [MSLB] outside containment compartment analysis), NSSS/balance-of-plant (BOP) interface, containment pressure and temperature analyses, and reactor core nuclear fuel. The NSSS scope was evaluated for 3216 MWt with 2-percent measurement uncertainty.

1.3.3 Stone & Webster

Stone & Webster (S&W) has been in the forefront of nuclear plant uprating, having successfully worked on over 23 plant uprating projects (completed or in progress) within the past 10 years. S&W has prepared implementation plans, design changes, and performed configuration management updates on the majority of these projects. Experience on these uprate projects, along with knowledge of the IP3 design, documentation system, and uprate project requirements has allowed S&W to develop a sound understanding of this project.

S&W has extensive experience in the design and analysis of BOP systems, including analyses and evaluations for uprates. Many of the S&W engineers assigned to the SPU are familiar with the IP3 design and analyses, having worked closely with Entergy plant personnel on the recent MUR Program. The S&W IP3 SPU Team members have recent experience in managing power uprate projects as well as significant engineering experience applicable to IP3.

S&W's analyses and evaluations include the BOP systems and components, including radiological and environmental evaluations. S&W also reviewed the effect on station programs.

The BOP scope of work includes engineering and associated review, evaluations, calculations, and analyses required to support the SPU at the uprated NSSS core power level of 3216 MWt and the projected initial operating power level. This work identifies effects and changes required to plant documentation and hardware, and demonstrates that the plant can operate safety, reliably, and meet regulatory requirements.

NSSS/BOP interface data were developed and exchanged among Entergy, Westinghouse, SWPC, and S&W. This information formed the foundation for the BOP reviews, evaluations, calculations, and analyses associated with the following:

- BOP systems and components
- Pipe stress and supports
- Structures
- Electrical
- BOP Instrumentation and controls
- BOP radiological review
- Environmental assessment
- Generic issues and programs
- Plant procedures

1.3.4 Siemens-Westinghouse Power Corporation and Alstom Power Generation Company

The scope of effort performed by SWPC included the engineering study to evaluate the high-pressure turbine for the SPU. The high-pressure turbine missile analysis was evaluated by SWPC.

The scope of effort performed by Alstom included the engineering study to evaluate the low-pressure turbine for SPU. Alstom (the supplier of the low-pressure turbines) reviewed the capability of the low-pressure turbine rotors for the IP3 SPU. Based on the design analysis, Alstom indicated that the rotors should be limited to an equivalent reactor power level increase of less than 4 percent. Thus, although the License Amendment Request is for 3216 MWt, the initial power increase following the approval of the license change will be limited to less than 4 percent until subsequent evaluation or modification can be made. The low pressure turbine missile analysis was evaluated by Alstom.

1.3.5 Structure of this Report

This Licensing Report is structured as follows:

Section 1, Introduction, presents background and general information related to the IP3 SPU.

Section 2, NSSS Analysis, presents the primary and secondary system design performance conditions (parameters) that were developed based on the SPU. These design performance conditions form the basis for all of the NSSS analyses and evaluations contained herein.

Section 3, NSSS and Auxiliary Equipment Design Transients, presents the results of evaluations of the design transients and how they accommodate the revised NSSS design conditions.

Sections 4, NSSS Systems, and 5, NSSS Components, present the NSSS systems (for example, safety injection, residual heat removal [RHR], and control systems) and components (for example, reactor vessel, pressurizer, reactor coolant pumps, steam generator, and NSSS auxiliary equipment) analyses, and evaluations completed for the SPU design conditions.

Section 6, Safety Analysis, provides the results of the accident analyses and evaluations performed for the various analyses areas (for example, steam generator tube rupture [SGTR], loss-of-coolant accident [LOCA] and non-LOCA accidents and transients, LOCA and MSLB mass and energy [M&E] releases, and radiological releases).

Section 7, Nuclear Fuel, addresses the effects of the uprate on the fuel and core design.

Section 8, Turbine Island Analysis, addresses the effects of the uprate on the main turbine.

Section 9, BOP Systems, addresses the effects of the uprate on the BOP systems.

Section 10, Generic Issues and Programs, addresses the effects of the uprate in the areas of plant programs and operating procedures.

Section 11, Environmental Impacts, addresses the effects of the uprate on the environmental criteria.

The analyses and evaluations described herein demonstrate that all applicable acceptance criteria will continue to be met based on operation at the SPU conditions at 3216 MWt, and that there are no significant hazards related to this power uprate according to the regulatory criteria of 10CFR50.92 (Reference 1).

1.3.6 References

1. 10CFR50.92, *Issuance of Amendment*, March 6, 1986.

1.4 Power Uprate Project Review Process

1.4.1 Input Parameters and Assumptions

Comprehensive analysis input assumption lists were developed at the beginning of the IP3 SPU for the various analytical areas within the work scope of the project. These lists were used to identify the input and assumption requirements and to obtain Entergy input data and approval. Entergy performed a review of the values used for the SPU and revalidated the analysis inputs and assumptions provided to Westinghouse, S&W, and SWPC. In conjunction with developing the individual input assumption lists, a consolidated input assumption list was prepared to aid in the identification and control of input data and assumptions and to promote consistency across the various analytical areas within the SPU. These input assumption lists have been incorporated into a database for future use by IP3 in managing and controlling analysis inputs and assumptions. Where necessary, follow-up actions have been initiated to update design basis documents to reflect the inputs and assumptions used for the SPU.

The SPU analyses were performed to reflect the as-built and as-operated plant. If plant drawings (as-built) or plant documentation were required to obtain the latest plant information for use in SPU analyses, they were obtained from Entergy and used as appropriate to obtain the needed information.

1.4.2 Methodology and Computer Codes

1.4.2.1 Nuclear Steam Supply Systems

The methodology used in evaluating the effect of the SPU on the NSSS has been structured consistent with the methodology established in Westinghouse WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant* (Reference 1). Since submittal of WCAP-10263 to the NRC, the methodology has been used successfully as a basis for power uprate projects on over 33 plants for a total of 1619 MWe of installed capacity. The uprate projects have ranged from a 1.0-percent to a 26.3-percent increase above base licensed power level.

The methodology in WCAP-10263 (Reference 1) established the basis and criteria for power uprate projects, including the broad categories that must be addressed, such as NSSS performance parameters, design transients, systems, components, accidents, and nuclear fuel, as well as the interfaces between NSSS and the balance-of-plant (BOP) fluid systems. Inherent in this methodology are key points that promote correctness, consistency, and licensability. The key points include the use of well-defined analysis input assumptions and parameters values,

use of currently approved analytical techniques (for example, methodologies and computer codes), and use of currently applicable licensing criteria and standards.

The power uprate analyses and evaluations were performed in accordance with Westinghouse quality assurance requirements defined in the Westinghouse Quality Management System procedures, which comply with 10CFR50 Appendix B (Reference 2) criteria. These analyses and evaluations are in conformance with Westinghouse and industry codes, standards, and regulatory requirements applicable to IP3. Assumptions and acceptance criteria are provided in the appropriate sections of this report.

1.4.2.2 Computer Codes

The IP3 SPU analyses and evaluations were performed using currently approved analytical techniques to demonstrate compliance with the licensing criteria and standards that apply to IP3. In performing these analyses, methodologies and principal computer codes were used that are currently approved by the NRC. Such codes and methods have been used for IP3 and the SPU consistent with any applicable NRC guidelines or limitations.

RETRAN has previously been approved by NRC for non-loss-of-coolant accident (non-LOCA) analyses. It has been generically approved in the *Safety Evaluation Report* (SER) for WCAP-14882-P-A (Reference 3), and is applicable for use at IP3.

The GTSTRUDL computer code has not been previously used on IP3 supports analyses. GTSTRUDL is a widely used industry code for analyzing steel structures such as supports.

The other principal analytical techniques are the same as those used for current IP3 analyses as described in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 4), or in the 1.4-percent MUR LAR.

Table 1-3 contains a list of the principal computer codes used in analyses documented in this Licensing Report. Brief descriptions of the computer codes are provided in Table 1-4.

Any computer codes used in the BOP analyses are industry standards or are in compliance with S&W's quality assurance program that meets 10CFR50 Appendix B (Reference 2) and do not require specific NRC review prior to use. The computer codes used in the BOP sections are mentioned as a part of the description of the evaluation performed.

1.4.2.3 Balance of Plant

The methodology used for the BOP evaluation was the same as that used successfully in many other Power Uprate Projects. The BOP systems, structures, and components were evaluated based on the existing design and licensing basis documented in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 4) and *Technical Specification* bases. Summary results are provided in Sections 8, 9, and 10 of this report.

1.4.3 References

1. WCAP-10263, *A Review Plan for Uprating the Licensed Power of a PWR Power Plant*, 1983.

2. 10CFR50, *Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants*, December 11, 1996.

3. *Safety Evaluation Report* (SER) for WCAP-14882-P-A. (Contained in WCAP-14882-P-A (Proprietary), *RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses*, D. S. Huegel, et al., April 1999.)

4. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286.

1.5 Modifications

Reviews, analyses, and evaluations performed for the IP3 SPU have determined that no significant modifications are required to accommodate the uprate to 3216 MWt. To provide additional margin for plant operation and equipment lifetime and to optimize operating points, modifications have been identified to the following equipment for implementation of the first phase of the IP3 SPU to approximately 4 percent :

- High-pressure turbine steam path
- Moisture separator reheater (MSR)
- First-stage turbine pressure taps
- Main power transformer monitoring

To address industry issues, the following modifications are planned in conjunction with the SPU reanalysis effort.

- High-head safety injection (HHSI) flow paths
- Control room heating, ventilation, and air conditioning (HVAC) upgrades

In addition to these noted modifications, some modifications will be made to instrument ranges, and to Operating and Emergency Operating Procedures (EOPs) and setpoints.

Also, Entergy has planned to implement other modifications separate from, but concurrent with the SPU at the start of Cycle 14. These include a minor structural upgrade to the fuel assemblies planned for the reload region. The various SPU analyses and evaluations described in this report have accounted for these other modifications as necessary.

To support the completion of the SPU above the approximate initial 4 percent, the following equipment will require modification:

- Low-pressure turbine – The low-pressure (LP) turbine components were originally dimensioned for 105-percent steam flow. This applies to LP blading, inner casing, and rotors with couplings. These components can therefore be operated at a 5 percent higher steam flow rate; 9900 klb/hr at an LP inlet pressure of 203 psia. The LP turbines will operate within these design parameters at the Phase 1 power level. An increase in reactor power output to 3216 MWt necessitates modification of the LP blades to increase the swallowing capacity of the three LP turbines so that the permissible LP inlet pressure is not exceeded at the higher steam flow rate.

- Iso-Phase Bus (IPB) - The IPB main bus continuous current design ratings (forced air-cooled rating of 32 kA at 23 kV, 65°C rise) will support unit operation within the reactive power capabilities defined by the Phase 1 SPU (1080 MWe, 225 MVAR lagging to 100 MVAR leading). The IPB tap bus continuous current design rating is also capable of operation at Phase 1 SPU conditions. The IPB system requires modification or administrative limits on load management to ensure operation within the main bus and tap bus continuous current design ratings at the maximum analyzed reactor thermal power (3216 MWt) and maximum generator reactive capability (1093.5 MWe, 267 MVAR lagging).

In addition to these noted modifications, some modifications will also be made to instrument setpoints in Phase 2

1.6 Proprietary Information Designations

Westinghouse

There is information contained in this report that Westinghouse considers Westinghouse Proprietary. The specific information is contained within the brackets with designated superscripted letter (a through f), for example:

[Westinghouse Proprietary Information]^{a,c,e}

The reason for marking Westinghouse Proprietary information in this report is so that if any portion of this report is used to prepare documents to be submitted to the NRC (for example, a licensing report), the authors will be aware of exactly which information is proprietary to Westinghouse and can protect the information accordingly. When a licensing report or any other document is submitted to the NRC for review, either the information proprietary to Westinghouse Electric Company LLC must be omitted from the submittal, or a nonproprietary version suitable for public disclosure must also be submitted.

1.7 Conclusions

This report demonstrates that the SPU can be safely implemented at IP3. The analyses and evaluations described herein demonstrate that all applicable acceptance criteria will continue to be met based on operation at the SPU conditions at 3216-MWt core power, and that there are no significant hazards related to this power uprate according to the regulatory criteria of 10CFR50.92 (Reference 1). Specifically, this SPU can be accommodated without a significant increase in the probability or consequences of an accident previously evaluated, without creating the possibility of a new or different type of accident from any accident previously evaluated, and without exceeding any presently existing regulatory limits applicable to the plants, which may cause a significant reduction in the margin of safety.

Furthermore, Entergy has evaluated the capability of IP3 plant systems and components and has determined that, with minor modifications, the plant systems and components are capable of safely supporting the subject increase in rated core thermal power. The capability of the low-pressure turbine rotors will initially be limited to an equivalent reactor power increase of less than 4 percent. Thus, although the LAR is for 3216 MWt, the initial power increase following the approval of the license change will be limited to less than 4 percent until subsequent evaluation or modification can be made.

This IP3 SPU document is a summary of how the plant NSSS and BOP systems and components, transient and accident analyses, containment and reactor core, as well as nuclear fuel, have been addressed to support operation at the SPU power at IP3. The results of the NSSS and BOP analyses and evaluations satisfy the project purpose to demonstrate compliance with all applicable licensing criteria and requirements. Furthermore, the evaluations and analyses have identified the plant modifications required and the operational effects of the SPU. These effects have been properly documented in accordance with plant policy and procedures. This document, in combination with referenced supporting documentation, forms the basis for the IP3 SPU to 3216 MWt.

1.7.1 References

1. 10CFR50.92, *Issuance of Amendment*, March 6, 1986.

Table 1-1

Cross-Reference of Licensing Report Sections to Topical Areas

Materials and Chemical Engineering	Licensing Report Section
Reactor Vessel Material Surveillance Program	5.1 Reactor Vessel
Pressure-Temperature Limits and Upper Shelf Energy	5.1 Reactor Vessel
Pressurized Thermal Shock	5.1 Reactor Vessel
Reactor Internal and Core Support Materials	5.10 Reactor Coolant System (RCS) Potential Material Degradation Assessment
Reactor Coolant Pressure Boundary Materials	5.0 Nuclear Steam Supply System (NSSS) Components 5.10 RCS Potential Material Degradation Assessment
Leak-Before-Break (LBB)	5.4.2 Application of LBB Methodology
Protective Coating Systems (Paints) – Organic Materials	Existing requirements for protective coatings are being retained
Effect of Power Uprate on Flow Accelerated Corrosion	10.3 Flow-Accelerated Corrosion Program
Steam Generator Tube Inservice Inspection	5.6 Steam Generators
Steam Generator Blowdown System	9.5 Steam Generator Blowdown System
Chemical and Volume Control System - Including Boron Recovery	4.1.2 Chemical and Volume Control System
Reactor Water Cleanup System (Boiling Water Reactor [BWR])	NA
Pipe Rupture Locations and Associated Dynamic Effects	5.4 Reactor Coolant Loop Piping and Supports 9.9 Piping and Supports
Pressure-Retaining Components and Component Supports	4.1 Nuclear Steam Supply Fluid Systems 5.1 Reactor Vessel 5.3 Control Rod Drive Mechanisms 5.4 Reactor Coolant Loop Piping and Supports 5.7 Pressurizer 5.6 Steam Generators 5.5 Reactor Coolant Pumps and Motors 5.8 Nuclear Steam Supply System Auxiliary Equipment 9.0 Balance of Plant (BOP) Systems 9.9 Piping and Supports

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Materials and Chemical Engineering (Cont.)	Licensing Report Section	
Reactor Pressure Vessel Internals and Core Supports	5.2	Reactor Pressure Vessel System
Safety-Related Valves and Pumps	4.1	Nuclear Steam Supply Fluid Systems
	5.8	Nuclear Steam Supply System Auxiliary Equipment
	10.2	Generic Letter 89-10 Motor-Operated Valve Program
Seismic and Dynamic Qualification of Mechanical and Electrical Equipment	5.1	Reactor Vessel
	5.3	Control Rod Drive Mechanisms
	5.4	Reactor Coolant Loop Piping and Supports
	5.7	Pressurizer
	5.6	Steam Generators
	5.5	Reactor Coolant Pumps and Motors
	5.8	NSSS Auxiliary Equipment
	9.0	BOP Systems
	10.8	Electrical Equipment Environmental Qualification Program

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Electrical Engineering	Licensing Report Section
Environmental Qualification of Electrical Equipment	10.8 Electrical Equipment Environmental Qualification Program
Offsite Power System	9.8 Electrical Systems
AC Onsite Power System	9.8 Electrical Systems
DC Onsite Power System	9.8 Electrical Systems
Station Blackout	4.1.3 Residual Heat Removal System 4.1.6 Component Cooling Water System 10.6 Station Blackout

Instrumentation and Controls (I&C)	Licensing Report Section
Reactor Trip System	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/ESF Actuation System Setpoints
ESF Systems	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/ESF Actuation System Setpoints
Safety Shutdown Systems	6.1 Initial Condition Uncertainties 6.10 Reactor Trip System/ESF Actuation System Setpoints
Control Systems	4.3 NSSS Control Systems 9.10 BOP Instrumentation and Controls
Diverse I&C Systems	N/A
General Guidance for Use of Other Standard Review Plan (SRP) Sections Related to I&C	4.3 NSSS Control Systems 9.10 BOP Instrumentation and Controls

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Plant Systems	Licensing Report Section
Flood Protection	10.4 Flooding
Equipment and Floor Drainage System	10.4 Flooding
Circulating Water System	9.7 Circulating Water System and Main Condenser
Internally Generated Missiles (Outside Containment)	4.1.8 NSSS Evaluation of Generation of and Protection from Missiles 8.1 Steam Turbine
Internally Generated Missiles (Inside Containment)	4.1.8 NSSS Evaluation of Generation of and Protection from Missiles
Turbine Generator	8.1 Steam Turbine
Protection against Postulated Piping Failures in Fluid Systems Outside Containment	9.9 Piping and Supports
Fire Protection Program	10.1 Fire Protection (10CFR50 Appendix R) Program
Pressurizer Relief Tank	4.1.1 Reactor Coolant System
Fission Product Control Systems and Structures	N/A
Main Condenser Evacuation System	9.7 Circulating Water System and Main Condenser
Turbine Gland Sealing System	9.1 Main Steam System
Main Steam Isolation Valve Leakage Control System	N/A
Spent Fuel Pit (SFP) Area Ventilation System	9.11 Area Ventilation (Heating, Ventilation, and Conditioning [HVAC])
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)
SFP Cooling and Cleanup System	4.1.7 SFP Cooling System
Station Service Water System	9.6 Essential and Non-Essential Service Water System
Reactor Auxiliary Cooling Water Systems	4.1.6 Component Cooling Water System
Ultimate Heat Sink	9.7 Circulating Water System and Main Condenser
Auxiliary Feedwater System	4.2 NSSS/BOP Interface Systems 6 Safety Analysis 9.12 Auxiliary Feedwater System

Table 1-1 (Cont.) Cross-Reference of Licensing Report Sections to Topical Areas	
Plant Systems (Cont.)	**Licensing Report Section**
Main Steam Supply System	9.1 Main Steam System
Main Condenser	9.7 Circulating Water System and Main Condenser
Turbine Bypass System	9.1 Main Steam System
Condensate and Feedwater System	9.4 Main Feedwater and Condensate System
Gaseous Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Liquid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Solid Waste Management Systems	6.11.6 Normal Operation Annual Radwaste Effluent Releases
Emergency Diesel Engine Fuel Oil Storage and Transfer System	9.8 Electrical Systems
Light Load Handling System (related to refueling)	6.11.5 Normal Operation Dose Rates and Shielding 6.11.9 Radiological Consequences Evaluations (Doses) 7.1 Fuel Design Features and Components

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Containments	Licensing Report Section
Dry Containments	6.5 Loss-of-Coolant Accident (LOCA) Containment Integrity 6.6.2 Steamline Break Containment Response Evaluation
Ice Condenser Containments	N/A
Pressure-Suppression Type BWR Containments	N/A
Subcompartment Analysis	6.5 LOCA Containment Integrity
Mass and Energy (M&E) Release for Postulated LOCA	6.5.1 Long-Term LOCA M&E Releases
M&E Release for Postulated Secondary System Pipe Ruptures	6.6.1 Main Steamline Break M&E Releases Inside Containment Responses 6.6.3 Main Steamline Break M&E Releases Outside Containment Responses
Combustible Gas Control in Containment	6.13 Post-LOCA Generation and Disposition of Hydrogen
Containment Heat Removal	4.1.4 Emergency Core Cooling System (ECCS) (Safety Injection System/Containment Spray System) 6.5 LOCA Containment Integrity 9.11 Area Ventilation (HVAC)
Secondary Containment Functional Design	N/A
Minimum Containment Pressure Analysis for ECCS Performance Capability Studies	6.2.1 Large-Break LOCA

Habitability, Filtration, and Ventilation	Licensing Report Section
Control Room Habitability System	6.11.9 Radiological Consequences Evaluations (Doses) 9.11 Area Ventilation (HVAC)
ESF Atmosphere Cleanup System	9.11 Area Ventilation (HVAC)
Control Room Area Ventilation System	9.11 Area Ventilation (HVAC)
SFP Area Ventilation System	9.11 Area Ventilation (HVAC)
Auxiliary and Radwaste Area Ventilation System	9.11 Area Ventilation (HVAC)
Turbine Area Ventilation System	9.11 Area Ventilation (HVAC)
ESF Ventilation System	9.11 Area Ventilation (HVAC)

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Reactor Systems	Licensing Report Section
Fuel System Design	7.1 Fuel Design Features and Components
Nuclear Design	7.3 Fuel Core Design 7.4 Fuel Rod Design and Performance
Thermal and Hydraulic Design	7.2 Core Thermal-Hydraulic Design
Functional Design of Control Rod Drive System	5.3 Control Rod Drive Mechanisms (CRDMs) 5.2.3 Rod Control Cluster Assembly (RCCA) Scram Performance Evaluation
Overpressure Protection during Power Operation	4.1 Nuclear Steam Supply System Fluid Systems 4.3.2 Pressurizer Pressure Control System Component Sizing 5.7 Pressurizer 6.3.6 Loss-of-External Electrical Load
Overpressure Protection during Low-Temperature Operation	4.3.3 Overpressure Protection System
Reactor Core Isolation Cooling System (BWR)	N/A
Residual Heat Removal System (RHRS)	4.1.3 RHRS
Emergency Core Cooling System	4.1.4 Emergency Core Cooling System (Safety Injection System/Containment Spray System)
Standby Liquid Control System (BWR)	N/A
Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	6.3.9 Excessive Heat Removal Due to Feedwater System Malfunction 6.3.10 Excessive Load Increase Incident 6.3.11 Rupture of a Steam Pipe
Steam System Piping Failures Inside and Outside Containment	6.3.11 Rupture of a Steam Pipe 6.6.2 Steamline Break Containment Response Evaluation 6.6.4 Main Steamline Break outside Containment Compartment Response
Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulator Failure (closed)	6.3.6 Loss-of-External Electrical Load
Loss of Non-Emergency AC Power to Station Auxiliaries	6.3.8 Loss-of-all AC (LOAC) to the Station Auxiliaries
Loss-of-Normal Feedwater Flow	6.3.7 Loss-of-Normal Feedwater
Feedwater System Pipe Breaks Inside and Outside Containment	Not in licensing basis
Loss-of-Forced Reactor-Coolant Flow including Trip of Pump Motor and Flow Controller Malfunctions	6.3.12 Partial Loss-of-Reactor-Coolant Flow 6.3.13 Complete Loss-of-Reactor-Coolant Flow

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Reactor Systems (Cont.)	Licensing Report Section
Reactor Coolant Pump (RCP) Rotor Seizure and Reactor Coolant Pump Shaft Break	6.3.14 Locked Rotor Accident
Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Condition	6.3.2 Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition
Uncontrolled Control Rod Assembly Withdrawal at Power	6.3.3 Uncontrolled RCCA Assembly Withdrawal at Power
Control Rod Misoperation (System Malfunction or Operator Error)	6.3.4 RCCA Drop/Misoperation
Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate	Table 6.3-1 List of Non-LOCA Events
Chemical and Volume Control System (CVCS) Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	6.3.5 CVCS Malfunction
Spectrum of Rod Ejection Accidents	6.3.15 Rupture of a CRDM Housing – RCCA Ejection
Spectrum of Rod Drop Accidents	6.3.4 RCCA Drop/Misoperation
Inadvertent Operation of ECCS and CVCS Malfunction that increases Reactor Coolant Inventory	NA
Inadvertent Opening of a Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve	6.2.2 Small-Break LOCA
Steam Generator Tube Rupture (SGTR)	6.4 SGTR Transient
LOCAs Resulting from Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary	6.2 Loss-of-Coolant Transients
Anticipated Transients Without Scram (ATWS)	6.8 ATWS
New Fuel Storage	4.1.7 SFP Cooling System 7.1 Fuel Design Features and Components
Spent Fuel Storage	4.1.7 SFP Cooling System 7.1 Fuel Design Features and Components

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Source Terms and Radiological Consequences Analysis	Licensing Report Section
Source Terms for Input into Radwaste Management Systems Analyses	6.11.4 Radiation Source Terms
Radiological Consequence Analyses Using Alternative Source Terms	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failures Outside Containment for a PWR	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Reactor Coolant Pump Rotor Seizure and RCP Shaft Break	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Ejection Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Control Rod Drop Accident	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of the Failure of Small Lines Carrying Primary Coolant outside Containment	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Steam Generator Tube Failure	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Main Steamline Failure Outside Containment for a BWR	N/A
Radiological Consequences of a Design Basis LOCA including Containment Leakage Contribution	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis LOCA Leakage from ESF Components outside Containment	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of a Design Basis LOCA Leakage from Main Steam Isolation Valves (BWR)	N/A
Radiological Consequences of Fuel-Handling Accidents	6.11.9 Radiological Consequences Evaluations (Doses)
Radiological Consequences of Spent Fuel Cask Drop Accidents	6.11.9 Radiological Consequences Evaluations (Doses)

Table 1-1 (Cont.)

Cross-Reference of Licensing Report Sections to Topical Areas

Health Physics	Licensing Report Section
Radiation Sources	6.11.4 Radiation Source Terms
Radiation Protection Design Features	6.11.5 Normal Operation Dose Rates and Shielding
Operational Radiation Protection Program	6.11.5 Normal Operation Dose Rates and Shielding

Human Performance	Licensing Report Section
Reactor Operating Training	10.15.2 Effect on Operator Actions and Training
Training for Non-Licensed Plant Staff	10.15.2 Effect on Operator Actions and Training
Operating and Emergency Operating Procedures (EOPs)	6.12 EOPs and EOP Setpoints 10.15.1 Procedures
Human Factors Engineering	10.15 Plant Operations

Health Physics	Licensing Report Section
Power Ascension and Testing	10.15.4 Startup Testing

Health Physics	Licensing Report Section
Risk Evaluation	10.5 Probabilistic Safety Assessment

Table 1-2 Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
Section 3: NSSS and Auxiliary Systems Design Transients			
3.1 NSSS Design Transients	Affected	Evaluation and Analysis	No(1)
3.2 Aux. Equipment Design Transients	Affected	Evaluation	No(1)
Section 4: NSSS Systems			
4.1.1 RCS	Affected	Evaluation and Analysis	No
4.1.2 CVCS	Affected	Evaluation	No
4.1.3 RHR	Affected	Analysis	No
4.1.4 ECCS (SIS and CSS)	Affected	Analysis	No
4.1.5 PSS	Affected	Evaluation and Analysis	No
4.1.6 CCWS	Affected	Evaluation and Analysis	No
4.1.7 SFPCS	Affected	Analysis	No
4.2.1 MSS	Affected	Analysis	No
4.2.2 Steam Dump	Affected	Analysis	No
4.2.3 C&FS	Affected	Evaluation and Analysis	No
4.2.4 AFWS	Affected	Analysis	No
4.2.5 SG Blowdown	Affected	Evaluation	No
4.3.1 NSSS Stability & Operability	Affected	Analysis	No
4.3.2 Pressurizer Pressure Control	Affected	Analysis	No
4.3.3 OPS	Unaffected	Evaluation	No
4.3.4 I&C Systems	Affected	Evaluation	NA

Table 1-2 (Cont.)

Guidance Matrix for IP3 SPU LR

LAR Section and System		Affected or Unaffected*	Method of SPU Reconciliation • New Analysis of Record • Evaluated Effect on Current Analysis of Record	Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)
Section 5: NSSS Components				
5.1.1	RV Structural	Affected	Evaluation	No
5.1.2	RV Integrity	Affected	Analysis	No
5.2.2	RV/RVI System T&H	Affected	Analysis	No
5.2.3	RCCA Scram Performance	Affected	Analysis	No
5.2.4	RV/RVI Mechanical	Affected	Analysis	No
5.2.5	RVI Components	Affected	Evaluation	No
5.2.6	BMI Guide Tubes	Affected	Analysis	No
5.3	CRDMs	Unaffected	Evaluation	No
5.4	RCL Piping/Supports	Affected	Analysis	No
5.5	RCP Pumps / Motors	Unaffected	Evaluation	No
5.6.1	SG T&H	Affected	Analysis	No
5.6.2	SG Structural	Affected	Analysis	No
5.6.3	Primary-to-Secondary ΔP	Affected	Analysis	No
5.6.4	SG Repair Hardware	Affected	Analysis	No
5.6.5	Reg. Guide 1.121	Affected	Analysis	No
5.6.6	SG Tube Vibration / Wear	Affected	Analysis	No
5.6.7	SG Tube Integrity	Affected	Evaluation	No
5.7	Pressurizer	Affected	Analysis	No
5.8	NSSS Auxiliary Equip.	Unaffected	Evaluation	No
5.9	NSSS Fracture Integrity	Affected	Analysis	No
5.10	NSSS Material Degradation	Affected	Evaluation	No(2)

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
Section 6: UFSAR Chapter 14 Safety Analyses			
6.1 Initial Condition Uncertainties	Affected	Analysis	No
6.2 LOCA Analyses	Affected	Evaluations and Analysis	No
6.3.2 Rod Withdrawal at Subcritical	Affected	Analysis	No
6.3.3 Rod Withdrawal at Power	Affected	Analysis	No
6.3.4 RCCA Drop	Affected	Analysis	No
6.3.5 CVCS Malfunction	Affected	Analysis	No
6.3.6 Loss of Load	Affected	Analysis	No
6.3.7 Loss of Normal Feedwater	Affected	Analysis(3)	No
6.3.8 Loss of AC Power	Affected	Analysis(3)	No
6.3.9 Feedwater Malfunction	Affected	Analysis	No
6.3.10 Excessive Load Increase	Affected	Evaluations and Analysis	No
6.3.11 Main Steamline Break	Affected	Analysis	No
6.3.12 Partial Loss of Flow	Affected	Analysis	No
6.3.13 Complete Loss of Flow	Affected	Analysis	No
6.3.14 Locked Rotor	Affected	Analysis	No
6.3.15 Rod Ejection	Affected	Analysis	No
6.4 SG Tube Rupture	Affected	Analysis	No
6.5 LOCA Containment Integrity	Affected	Analysis	No
6.6.2 MSLB Containment Integrity	Affected	Analysis	No
6.6.4 MSLB Outside Containment Compartment Response	Affected	Analysis	No
6.7 LOCA Forces	Affected	Analysis	No
6.8 ATWS	Affected	Evaluation	No
6.9 Natural Circulation Cooldown	Affected	Analysis	No
6.10 RPS/ESFAS Setpoints	Affected	Analysis	No

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
6.11 Radiological Dose	Affected	Analysis	No
6.12 EOPs and Setpoints	Affected	Analysis	No
6.13 Hydrogen Generation	Affected	Analysis	No
Section 7: Fuel and Core Analyses			
7.1 Fuel Design Features and Components (Mechanical)	Affected	Analysis	No
7.2 Core T&H	Affected	Analysis	No
7.3 Fuel Core Design	Affected	Analysis	No(4)
7.4 Fuel Rod Design and Performance	Affected	Analysis	No
7.5 Neutron Fluence	Affected	Analysis	No
7.6 Reactor Internals Heat Generation Rate for RVI	Affected	Analysis	No
Section 8: Turbine Island Analysis			
8.1 Steam Turbine	Affected	Analysis	No(5, 6)
8.2 Heat Balances	Affected	Analysis	No(7)
Section 9: BOP Systems and Components			
9.1 Main Steam System	Affected	Evaluations and Analysis	No(6)
9.2 Extraction Steam System	Affected	Evaluations and Analysis	No(6)
9.3 Heater Drain Systems	Affected	Evaluations and Analysis	No(6)
9.4 Main Feedwater and Condensate System	Affected	Evaluations and Analysis	No(6)
9.5 Steam Generator Blowdown	Unaffected	Evaluation	No(6)
9.6 Essential and Non-Essential Service Water	Affected	Evaluations and Analysis	No(6)

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
9.7 Circulating Water Systems and Main Condensate	Affected	Evaluations and Analysis	No(6)
9.8 Electrical Systems	Affected	Evaluations and Analysis	No(6)
9.9 Piping and Supports	Affected	Evaluations and Analysis	No(8)
9.10 BOP Instruments and Control	Unaffected	Evaluation	No(9)
9.11 Area Ventilation (HVAC)	Unaffected	Evaluation	No
9.12 Auxiliary Feedwater System	Affected	Evaluations and Analysis	No(10)
9.13 Structural Analysis (FHB/AFB)	Affected	Evaluations and Analysis	No(6)
Section 10: Generic Issues and Programs			
10.1 Fire Protection (App.R) Program	Unaffected	Evaluation	No(10)
10.2 GL 89-10 MOV Program	Unaffected	Evaluation	No
10.3 Flow-Accelerated Corrosion FAC Program	Affected	Evaluations and Analysis	No
10.4 Flooding	Unaffected	Evaluation	No
10.5 Probabilistic Safety Assessment	Affected	Evaluation	No
10.6 Station Blackout	Unaffected	Evaluation	No
10.7 In-Service Inspection, Testing (ISI, IST)	Affected	Evaluation	No
10.8 Electrical Equipment / EQ (inside & outside cont.)	Affected	Evaluations and Analysis	No
10.9 Chemistry Program	Unaffected	Evaluation	No
10.10 GL 95-07	Unaffected	Evaluation	No(6)
10.11 GL 96-06	Unaffected	Evaluation	No(6)
10.12 GL 89-13	Unaffected	Evaluation	No

Table 1-2 (Cont.) Guidance Matrix for IP3 SPU LR			
LAR Section and System	**Affected or Unaffected***	**Method of SPU Reconciliation** • New Analysis of Record • Evaluated Effect on Current Analysis of Record	**Change to Current Design or Licensing Basis Acceptance Criteria (YES / NO)**
10.13 Plant Simulator	Affected	Evaluations and Analysis	No
10.14 Containment Leak Rate Testing	Affected	Evaluations and Analysis	No(6)
10.15 Plant Operations	Affected	Evaluations and Analysis	No
Section 11: Environmental Impacts			
11 Environmental Impacts	Unaffected	Evaluations and Analysis	No

*According to the NRC Guidance for Margin Uncertainty Recapture power uprates in RIS 2002-03:

Unaffected – Unaffected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that bound the potential effects of the SPU.

Affected – Affected systems, components, or safety analyses are those having current design and licensing bases analyses and calculations that do not bound the potential effects of the SPU.

Notes:

1. Design Transients do not have acceptance criteria. Acceptance Criteria are applied to the NSSS components that are analyzed for the NSSS transients.
2. Materials requirements and evaluations continue to be applicable. Technique for evaluation of I-600 susceptibility was not previously applied to IP3.
3. Analysis input assumption changed to credit 10 minute operator action to provide additional AFW flow.
4. Core designs are checked for each reload cycle to ensure that design bases conditions are bounded.
5. Confirmation that the existing Turbine Missile analysis remains valid
6. The original licensing basis acceptance criteria for the BOP systems and components were not detailed. The criteria required that the systems function to produce power and provide reliable operation with minimal transients or trips. For the SPU, these systems were compared to industry standards and criteria to determine acceptability.
7. There are no acceptance criteria for the Heat Balance per se. The heat balance results are the inputs used for BOP systems and components evaluations and analyses.
8. BOP piping and supports were evaluated based on change factors.
9. Evaluation was based on revised Heat Balance parameters and applicable system analysis compared to instrument ranges.
10. The Licensing Basis Acceptance Criteria for this system are the acceptance criteria for the operational or safety analyses for which operation of this system or component is assumed.

Table 1-3 IP3 SPU Principal Computer Codes Used			
Report Section	**Analysis**	**Computer Code(1)**	**Previously Used by IP3 or Accepted by NRC**
4.3	Control Systems Operability – Margin-to-Trip Analysis	LOFTRAN (LOFT12)	Yes(2)
5.2	Reactor Internals	WECAN THRIVE	Yes(2) Yes
5.4	RCS Piping and Supports	WESTDYN GTSTRUDL	Yes(2) No(3)
5.6	Steam Generator Thermal-Hydraulic	GENF ATHOS	Yes(2) Yes(2)
6.2	Large-Break Best-Estimate LOCA (LBBELOCA)	WCOBRA/TRAC	Yes(2)
	Small-Break LOCA (SBLOCA)	NOTRUMP/ SBLOCTA	Yes(2) Yes(2)
6.3	Non-LOCA Transients	ANC FACTRAN PHOENIX-P RETRAN TWINKLE VIPRE LOFTRAN	Yes(2) Yes(2) Yes(2) Yes(4) Yes(2) Yes(2) Yes(2)
6.4	SGTR	LOFTTR2	Yes(2)
6.5	LOCA M&E LOCA Integrity Inside Containment	SATAN VI WREFLOOD EPITOME FROTH COCO	Yes(2) Yes(2) Yes(2) Yes(2) Yes(2)
6.6	MSLB inside Containment MSLB outside Containment	COCO GOTHIC	Yes(2) Yes(2)
6.6	MSLB M&E	LOFTRAN	Yes(2)
6.7	LOCA Hydraulic Forces	MULTIFLEX 3.0 LATFORC FORCE 2 THRUST	Yes(2) Yes(2) Yes(2) Yes(2)

Table 1-3 (Cont.)

IP3 SPU

Principal Computer Codes Used

Report Section	Analysis	Computer Code[1]	Previously Used by IP3 or Accepted by NRC
6.11	Radiation Source Terms	ORIGEN2.1	Yes[5]
7.1	Fuel Assemblies	NKMODE WEGAP WECAN	Yes[2] Yes[2] Yes[2]
7.2	Core Thermal-Hydraulic Design	THINC IV VIPRE	Yes[2] Yes[2]
7.3	Core Design	ANC PHOENIX-P	Yes[2] Yes[2]
7.4	Fuel Rod Design and Performance	PAD 3.4; PAD 4.0	Yes[2]
7.5	Neutron Fluence	DORT/BUGLE-96	Yes[2]
7.6	Reactor Internals Heat Generation Rates	DORT/BUGLE-96	Yes[2]

Notes:

1. See Table 1-4 for a brief description of each code.
2. Used in IP3 UFSAR or 1.4% Measurement Uncertainty Recapture (MUR) License Amendment Request.
3. GTSTRUDL is a widely used industry computer code for structural analysis.
4. RETRAN code and methods were generically approved by NRC *Safety Evaluation Report* (SER) on WCAP-14882-P-A and are applicable for use at IP3.
5. ORIGEN2.1 is a widely used transport and radiation source term code that is noted as acceptable in Regulatory Guide (RG) 1.183.

Table 1-4
Computer Code Description

ANC

ANC is an advanced nodal code capable of two-dimensional and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates one-dimensional (1-D) and two-dimensional (2-D) results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information.

ATHOS

ATHOS is a three-dimensional computer program for computational fluid dynamics (CFD) analysis of steam generators. The ATHOS code was developed under the sponsorship of the Electric Power Research Institute (EPRI).

The ATHOS code consists of geometry pre-processor, ATHOS solution, and post-processor modules. The geometry pre-processor simulates the detailed geometry. This geometry simulation includes the detailed tube layout, tube lane blocks, flow distribution baffle, tube support plates, anti-vibration bars (AVB), and opening of the primary separators. The geometry model links thermally with the primary side coolant flow. This thermal link allows the ATHOS module to calculate heat transfer from the primary coolant flow to the secondary side fluid. Therefore, the ATHOS code will calculate both heat flux and tube wall temperature, in addition to typical parameters such as liquid velocity, vapor velocity, steam quality for a two-phase flow like that in the secondary side of a steam generator.

The ATHOS code for the CFD analysis of steam generators has been verified and qualified by EPRI and Westinghouse. The post-processors can process the large amounts of output from the ATHOS calculation. Their capabilities include: (1) velocity vector plots, and (2) contour plots of thermal hydraulic parameters, such as steam quality, velocity, heat flux, and critical steam quality corresponding to departure from nucleate boiling (DNB).

Table 1-4 (Cont.)
Computer Code Description

COCO

Calculation of containment pressure and temperature is accomplished by use of the digital computer code COCO. COCO is a mathematical model of a generalized containment. The proper selection of various options in the code allows the creation of a specific model for a particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and found acceptable to calculate containment pressure transients for many dry containment plants. Transient phenomena within the RCS affect containment conditions by means of convective mass and energy transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water (pool) phase and a steam-air phase. Sufficient relationships to describe the transient are provided by the equations of conservation of M&E as applied to each system, together with appropriate boundary conditions. Since thermo-dynamic equations of state and conditions may vary during the transient, the equations have been derived for all possible cases of superheated or saturated steam and subcooled or saturated water. Switching between states is handled automatically by the code.

DORT/BUGLE-96

The DORT discrete ordinates transport module of the DOORS 3.1 code package, in conjunction with the BUGLE-96 cross-section library, is used to determine the neutron flux and gamma-ray heating rate environment. This code and the associated cross-section library have been used by Westinghouse to calculate vessel fluences and reactor internals heating rates for other projects that have been submitted to, and approved by, the NRC. Furthermore, these calculational tools are specified in Regulatory Guide (RG) 1.190 for this type of work.

EPITOME (see also SATAN-VI and WREFLOOD)

The EPITOME code continues the post-reflood portion of the transient from the time at which the secondary side equilibrates to containment design pressure until the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables, and M&E balance tables with data at critical times. EPITOME is essentially an automated hand calculation.

Table 1-4 (Cont.)
Computer Code Description

FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal-clad UO_2 fuel rod and the transient heat flux at the surface of the cladding, using as input the nuclear power and the time-dependent coolant parameters of pressure, flow, temperature, and density. The code uses a fuel model that simultaneously contains the following features:

- A sufficiently large number of radial space increments to handle fast transients, such as a rod ejection accident.
- Material properties that are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation.
- The necessary calculations to handle post-departure from nucleate boiling (DNB) transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel.

FORCE2 (See also MULTIFLEX, LATFORC, and THRUST)

The FORCE2 program calculates the hydraulic forces that the fluid exerts on the vessel internals in the vertical direction by using a detailed geometric description of the vessel components along with the transient pressures, mass velocities, and densities computed by the MULTIFLEX code. The analytical basis for the derivation of the mathematical equations employed in the FORCE2 code is the conservation of linear momentum (1-D). Note that the computed vertical forces in the LOCA forces analyses do not include body forces on the vessel internals, such as deadweight or buoyancy. The deadweight and other factors are part of the dynamic system model to which the LOCA forces are provided as an external load. When the vertical forces on the reactor pressure vessel (RPV) internals are calculated, pressure differential forces, flow stagnation on, and unrecoverable orifice losses across, and friction losses on, the individual components are considered. These force types are then summed together, depending upon the significance of each, to yield the total vertical force acting on a given component.

Table 1-4 (Cont.)
Computer Code Description

FROTH

The FROTH code is used for computing the post-reflood transient. The FROTH code calculates the heat release rates resulting from a two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken loop and intact loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side. Therefore, there is a significant amount of reverse heat transfer that occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs, and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two phase. During the FROTH calculation ECCS injection is addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure, after this point the EPITOME code completes the steam generator depressurization.

GENF

GENF is a computer code developed for the steady-state, thermal-hydraulic analysis of non-preheat type vertical U-tube steam generators. Given the geometric parameters, feedwater temperature, primary side flow rate and pressure, GENF computes the circulation ratio, primary and secondary side pressure drops, secondary coolant mass inventory, stability damping factor, and depending on the mode of calculation chosen, steam pressure, primary temperatures, heat load or size of the tube bundle.

GOTHIC

GOTHIC solves the integral form of the conservation equations for mass, momentum, and energy for multi-component, two-phase flow. The conservation equations are solved for three fields; continuous liquid, liquid drops, and the steam/gas phase. The three fields may be in thermal non-equilibrium within the same computational cell. This would allow the modeling of subcooled drops (for example, containment spray) falling through an atmosphere of saturated steam. The gas component of the steam/gas field can comprise up to eight different non-condensable gases with mass balances performed for each component. Relative velocities are calculated for each field, as well as the effects of two-phase slip on pressure drop. Heat transfer among the phases, surfaces, and the fluid are also allowed. The GOTHIC code is capable of performing calculations in three modes. The code can be used in the lumped parameter nodal network mode, the 2-D finite difference mode, and the 3-D finite difference mode. Each of these modes may be used within the same model.

Table 1-4 (Cont.)
Computer Code Description

GOTHIC has been used to study hydrogen distributions, containment and compartment pressure and temperature transients, perform flow-field calculations for particle transport purposes, and surge-line flooding studies for loss of RHR cooling events during shutdown operations. The flexible noding and conservation equation solutions in the code allow its application to a wide variety of problems.

GTSTRUDL

GTSTRUDL is a finite element analysis tool suitable for general structural engineering design and analysis of framed structures, including beam, plate, and shell elements. GTSTRUDL can perform both linear and nonlinear static analyses, and linear dynamic analysis including response spectrum analysis and time history analysis. Code checking, including both AISC and ASME Section III Division 1 Subsection NF, is available.

LATFORC (See also MULTIFLEX, FORCE2, and THRUST)

The LATFORC computer code utilizes MULTIFLEX-generated field pressures, together with geometric vessel information (component radial and axial lengths), to determine the horizontal forces on the vessel wall and core barrel. The LATFORC code represents the vessel region with a model that is consistent with the model used in the MULTIFLEX blowdown calculation. The downcomer annulus is subdivided into cylindrical segments, formed by dividing this region into circumferential and axial zones. The results of the MULTIFLEX/LATFORC analysis of the horizontal forces are typically stored on magnetic tape and are calculated for the initial 500 msec of the blowdown transient. These forcing functions serve as required input in determining the resultant mechanical loads on primary equipment and loop supports, vessel internals, and fuel grids.

Table 1-4 (Cont.)
Computer Code Description

LOFTRAN

The LOFTRAN computer program is used for studies of transient response of a PWR system to specified perturbations in process parameters. LOFTRAN simulates up to four-loop systems by modeling the reactor vessel, hot- and cold-leg piping, steam generators (tube and shell sides), and pressurizer. The pressurizer heaters' spray, relief, and safety valves are also considered in the program. Point model neutron kinetics and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary sides of the steam generators use a homogeneous, saturated mixture for the thermal transients, and a water level correlation for indication and control. The Reactor Protection System (RPS) simulation includes reactor trips on neutron flux, over-power and over-temperature, reactor coolant ΔT, high and low pressure, low flow, and high pressurizer level. Control systems, including rod control, steam dump, feedwater control, and pressurizer pressure controls are also simulated. The Safety Injection System (SIS), including the accumulators, is also modeled. LOFTRAN is a versatile program suited to accident evaluation and control studies as well as parameter sizing. It is also used in performing loss of normal feedwater anticipated transient without scram (ATWS) and loss-of-load ATWS evaluations.

LOFT12 is a single-loop version of LOFTRAN used for symmetric transients. LOFT12 was also used in the previous control systems analysis for IP3.

LOFTTR2 is a version of LOFTRAN used for steam generator tube rupture analyses.

Both single-loop and multi-loop codes have been approved by the NRC.

MULTIFLEX

The analysis for LOCA hydraulic forces used the NRC-approved MULTIFLEX computer code, which is the current Westinghouse analytical tool for analyzing LOCA hydraulic forces. The code was used to generate the transient hydraulic forcing functions on the vessel and internals. This code was previously used for LOCA hydraulic forces analyses.

MULTIFLEX 3.0 is an engineering design tool that is used to analyze the coupled fluid-structural interactions in a PWR system during the transient following a postulated pipe rupture in the main RCS. The thermal-hydraulic portion of the MULTIFLEX code is based on the one-dimensional homogeneous model expressed in a set of mass, momentum, and energy conservation equations. These equations are quasi-linear, first-order, partial differential equations solved by the method of characteristics.

Table 1-4 (Cont.)
Computer Code Description

The employed numerical method utilizes an explicit time scheme along the respective characteristics. MULTIFLEX considers the interaction of the fluid and structure simultaneously, whereby the mechanical equations of vibration are solved through the use of the modal analysis technique. MULTIFLEX 3.0 generates the input for the post-processing codes LATFORC, FORCE2, and THRUST.

NKMODE

NKMODE is used to establish an equivalent finite element model that will preserve the dynamic properties of the fuel assembly. Parametric studies of the assembly vibrational frequencies and mode shapes are performed using NKMODE. NKMODE calculates a set of equivalent spring-mass elements representing an individual fuel assembly structural system.

NOTRUMP/SBLOCTA

The approved codes for Appendix K small-break LOCA (SBLOCA) analyses are NOTRUMP and SBLOCTA. The NOTRUMP computer code is a state-of-the-art, 1-D general network code consisting of a number of advanced features. Among these features are the calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flow limitations, mixture level tracking logic in multiple-stacked fluid nodes, and regime-dependent heat transfer correlations. Additional features of the code include a condensation heat transfer model applied in the steam generator region, a loop seal model, a core reflux model, flow regime mapping, etc.

The SBLOCTA computer code is used to model the fuel rod response to the SBLOCA transient. It models three rods in the hot assembly (hot, average, and adjacent), including simultaneous radial and axial conduction. Other modeling features include various skewed axial power shapes, assembly blockage model due to clad swell, and rupture and zirc/water reaction.

NOTRUMP is used to model the thermal-hydraulic behavior of the system and thereby obtain time- dependent values of various core region parameters, such as system pressure, temperature, fluid levels and flow rates, etc. These are provided as boundary conditions to SBLOCTA. SBLOCTA then uses these conditions and various hot channel inputs to calculate the rod heatup, and ultimately, the peak clad temperature (PCT) for a given transient. Additional variables calculated by SBLOCTA are cladding pressure, strain, and oxidation.

Table 1-4 (Cont.)
Computer Code Description

ORIGEN2.1

Fission product inventories were modeled with ORIGEN2, Version 2.1. ORIGEN2 is a versatile point-depletion and radioactive-decay computer code for use in simulating nuclear fuel cycles and calculating the nuclide compositions and characteristics of materials contained therein. The ORIGEN2 code is an industry-standard code based on the latest industry experimental data. In general, the data are up to date, well documented, and accepted by the industry. Furthermore, this calculational tool is specified in RG 1.183 for this type of work.

PAD 3.4/4.0

The NRC-approved PAD code, with NRC-approved models for in-reactor behavior, is used to calculate the fuel rod performance over its irradiation history. PAD is the principal design tool for evaluating fuel rod performance. PAD iteratively calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power. Fuel rod design and safety analyses are based on updated values (up to 100-percent helium gas release) for the integral fuel burnable absorber (IFBA) helium gas release model.

PAD is a best-estimate fuel rod performance model, and in most cases the design criterion evaluations are based on a best-estimate-plus-uncertainties approach. A statistical convolution of individual uncertainties due to design model uncertainties and fabrication dimensional tolerances is used. As-built dimensional uncertainties are measured for some critical inputs, for example, fuel pellet diameter, and when available, can be used in lieu of the fabrication uncertainties.

PHOENIX-P

PHOENIX-P is a 2-D, multi-group transport theory computer code. The nuclear cross-section library used by PHOENIX-P contains cross-section data based on a 70-energy-group structure derived from ENDF/B-VI files. PHOENIX-P performs a 2-D, 70-group nodal flux calculation that couples the individual subcell regions (pellet, cladding, and moderator) as well as surrounding rods via a collision probability technique. This 70-group solution is normalized by a coarse energy group flux solution derived from a discrete ordinates calculation. PHOENIX-P is capable of modeling all cell types needed for PWR core design applications.

Table 1-4 (Cont.)
Computer Code Description

RETRAN

RETRAN is used for studies of transient response of a PWR system to specified perturbations in process parameters. This code simulates a multi-loop system by a lumped parameter model containing the reactor vessel, hot- and cold-leg piping, RCPs, steam generators (tube and shell sides), main steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves may also be modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The RPS simulated in the code includes reactor trips on high neutron flux, overtemperature ΔT (OTΔT) and overpressure ΔT (OPΔT), low RCS flow, high- and low-pressurizer pressure, high-pressurizer level, and lo-lo steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the SIS, including the accumulators, may be modeled. RETRAN calculates the transient value of departure from nucleate boiling rate (DNBR) based on input from the core thermal safety limits.

SATAN-VI (See also WREFLOOD and EPITOME)

The SATAN code utilizes the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform, and thermo-dynamic equilibrium is assumed in each element. A point-kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for subcooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis.

Table 1-4 (Cont.)
Computer Code Description

THINC IV

The THINC-IV computer program is used to determine coolant density, mass velocity, enthalpy, vapor void, static pressure, and DNBR distributions along parallel flow channels within a reactor core under expected steady-state operating conditions. This code has had extensive experimental verification and is considered a best-estimate code. The THINC-IV analysis is based on a knowledge and understanding of the heat transfer and hydro-dynamic behavior of the coolant flow and the mechanical characteristics of the fuel elements. The THINC-IV analysis provides a realistic evaluation of the core performance.

THRIVE

The Thermal Hydraulic Reactor Internals Vessel Evaluation (or THRIVE) code models the reactor vessel and internals system in Westinghouse PWRs and performs the following computations:

- Reactor vessel pressure losses for the thermal design, best estimate, mechanical design, hot-pump overspeed, and cold-full flow rates
- Reactor vessel-internals associated core bypass flows
- Reactor internals baffle-barrel region flow rates
- Baffle joint momentum flux and baffle jetting margins of safety
- Baffle plate pressure relief hole velocities
- Reactor internals hydraulic uplift forces
- Hydraulic and geometrical data for use in nuclear safety, fluid systems and reactor internals component analyses

The THRIVE code predicts the RV pressure losses by classical analytical fluid mechanics. THRIVE solves the following continuity and momentum equations for a flow system that represents the entire reactor vessel and internals system:

$$W = \rho VA = \text{constant}$$

$$P_j = P_i + \sum_{i}^{j} (K + fl/D)\frac{\rho V^2}{2 g_c}$$

Table 1-4 (Cont.)
Computer Code Description

- Ability to mechanistically represent interfacial heat, mass, and momentum transfer in different flow regimes
- Ability to represent important reactor components such as fuel rods, steam generators, RCPs, etc.

WECAN

The WECAN computer code is a general-purpose, finite element code with capabilities including structural and thermal-hydraulic static and dynamic analyses. It is a direct descendent of the mainframe-version of the WECAN code that has been used in the nuclear industry since the early 1970s. It has been used by Westinghouse for safety-related work for many years on essentially all Westinghouse-provided NSSS analyses, such as core structural design (analyses including static, dynamic, and thermal), primary piping, primary equipment supports, primary equipment components, and spent fuel rack design.

The WECAN computer program can be used to solve a large variety of structural analysis problems. These problems can be 1-, 2-, or 3-D in nature. It is capable of static elastic and inelastic analysis, steady-state hydraulic analysis, standard and reduced modal analysis, harmonic response analysis, and transient dynamic analysis.

The WECAN program is based on the finite element method of analysis. The analyst must model, or idealize, the structure in terms of discrete elements and apply loadings and boundary conditions to these elements. The stiffness (or conductivity) matrix for each element is assembled into a system of simultaneous linear equations for the entire structure. This set of equations is then solved by a variation of the Gaussian elimination method known as the wave-front technique. This type of solution makes it possible to solve systems with a large number of degrees of freedom using a minimum amount of core storage. The maximum number of allowed degrees of freedom in the wave front depends on the amount of core available, which in turn depends on the type of analysis being performed.

WECAN is organized in such a way that additional structural elements can be added with a minimum of effort. Input formats are similar for all elements and all types of analysis. Input used in the static analysis of a structure can be used for a dynamic analysis with only minor modifications.

Table 1-4 (Cont.)
Computer Code Description

WEGAP

WEGAP calculates the dynamic structural response of a PWR core. WEGAP represents the transient structural response of one row of fuel assemblies, including impact at the grid elevation. With the appropriate analysis parameters such as grid impact stiffness and damping, the number of fuel assemblies in a planar array and gap clearance established, the WEGAP reactor core model is used for analyzing transient loadings.

WESTDYN

WESTDYN, a computer program used for the structural analysis of piping systems, calculates displacement, internal forces, and stress distributions in 3-D piping models, while subjecting them to static and dynamic loads.

The static analysis includes pressure, deadweight, thermal expansion, distributed and point loads, anchor motion, and uniformly applied accelerations.

The dynamic analysis includes seismic or hydro-dynamic response spectra and time-history dynamic analysis. The time-history dynamic analysis includes options for non-linear supports, support gaps, and unidirectional single acting restraints.

In addition, WESTDYN uses post-processors for the stress analysis of American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3, or ANSI B31.1 piping, and also for generating support load summary sheets and equipment, and component qualification input data.

WESTDYN automatically calculates stress indices for standard ANSI fittings by user selection of the ASME piping evaluation code and edition. Allowable piping stress limits, coefficients of thermal expansion, and moduli of elasticity for a wide range of materials are also automatically calculated with user-supplied design and operating data.

Table 1-4 (Cont.)
Computer Code Description

WREFLOOD (See also SATAN-IV and EPITOME)

The WREFLOOD code is used for computing the reflood transient. It addresses the portion of the LOCA transient where the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break, and when water supplied by the Emergency Core Cooling System (ECCS) refills the reactor vessel and cools the core.

The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel, and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped safety injection and accumulators, RCP performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters, such as core flooding rate, core downcomer water levels, fluid thermo-dynamic conditions (that is, pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system.

2.0 NUCLEAR STEAM SUPPLY SYSTEM ANALYSIS

The stretch power uprate (SPU) included Nuclear Steam Supply System (NSSS) performance analyses to develop bounding NSSS Performance Capability Working Group (PCWG) parameters for use in the analyses and evaluations of the NSSS, including parameters for NSSS design transients and analyses of systems, components, accidents, and nuclear fuel.

2.1 Nuclear Steam Supply System Parameters

2.1.1 NSSS Performance Capability Working Group Parameters

The Nuclear Steam Supply System (NSSS) primary and secondary system design parameters are the fundamental system condition inputs (temperatures, pressures, and flow) that are used as the basis for all of the NSSS analyses and evaluations. They provide the Reactor Coolant System (RCS) and secondary system conditions (temperatures, pressures, flow) that are used as the basis for the design transients and for systems, components, accidents, and fuel analyses and evaluations. Revised design parameters were developed to reflect the increase in the Indian Point Unit 3 (IP3) licensed core power from 3067.4 to 3216 MWt. The parameters for the 3067.4-MWt measurement uncertainty recapture (MUR) are shown in Table 2.1-1 (Reference 1). The stretch power uprate (SPU) parameters are shown in Table 2.1-2. As discussed in this report, the parameters in Table 2.1-2 have been reconciled with the applicable systems and components evaluations, as well as safety analyses, performed in support of the SPU.

The PCWG parameters were established using conservative assumptions to provide bounding conditions to be used in the NSSS analyses. For example, the RCS flow assumed in generating the primary and secondary side conditions was the thermal design flow (TDF), which was a conservatively low flow that accounted for flow measurement uncertainty and assumed a steam generator tube plugging (SGTP) level of 10 percent. The resulting primary and secondary side design conditions will bound actual plant operations at the 3216-MWt SPU level.

The method and mathematical model used to calculate the IP3 design parameter values in Table 2.1-2 used basic thermal, hydraulic, and engineering principles, including mass and energy (M&E) balances. The code used to determine the NSSS design parameters is called SGPER (Steam Generator PERformance). Explicit NRC approval is not needed for SGPER, since it is used to facilitate fundamental engineering calculations that could be performed by hand. The code, method, and mathematical model have been successfully used to support all previous uprates for Westinghouse plants.

2.1.2 Input Parameters and Assumptions

Four cases of design performance parameters were developed for the IP3 SPU to cover combinations of SGTP and T_{avg} operating conditions. The following assumptions were common to all four sets:

- Westinghouse Model 44F steam generators

- TDF of 88,600 gpm/loop
- NSSS uprated power level of 3216 MWt core power with a high value of 14 MWt net heat input from the primary RCS reactor coolant pumps (RCPs)
- Westinghouse 15 x 15 Vantage+ and upgrade fuel design (see Section 7.0)
- Total design core bypass flow of 5.5 and 7.5 percent that accounts for intermediate flow mixing (IFM) grids
- T_{feed} range of 433.6° to 390°F

2.1.3 Discussion of Parameter Cases

Table 2.1-2 provides the NSSS design parameter cases generated and used as the basis for the SPU. Four cases were developed.

The four cases are distinguished as follows:

Case 1 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 0-percent SGTP.

Case 2 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 10-percent SGTP.

Case 3 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 0-percent SGTP.

Case 4 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 10-percent SGTP.

2.1.4 Acceptance Criterion

There are no specific acceptance criteria for this section. The PCWG parameters provide bounding conditions to be used in the NSSS analyses with appropriate levels of conservativism that would also provide Entergy with adequate margin for plant operation and to meet design

and licensing bases acceptance criteria. Where the analyses determined a more limiting condition, that is noted in the discussion for each analysis.

2.1.5 Results and Conclusions

The resulting PCWG parameters are shown in Table 2.1-2.

2.1.6 References

1. Entergy Nuclear Operations, Incorporated, *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, May 2002. (Approved in License Amendment 213 on November 26, 2002.)

Table 2.1-1

Design Power Capability Parameters
IP3 3067.4 MWt (Current Plant Design)

Thermal Design Parameters	**Set 1**	**Set 2**	**Set 3**
NSSS Power %	100	100	100
MWt	3082	3082	3082
10^6 Btu/hr	10,516	10,516	10,516
Reactor Power MWt[(1)]	3068[(1)]	3068[(1)]	3068[(1)]
10^6 Btu/hr	10,468	10,468	10,468
Thermal Design Flow, loop gpm	89,700	80,900	80,900
Reactor 10^6 lb/hr	136.3	123.4	122.9
Reactor Coolant Pressure, psia	2250	2250	2250
Core Bypass, %	5.2	5.2	5.2
Reactor Coolant Temperature, °F			
Core Outlet	603.7	607.0	610.0
Vessel Outlet	600.8	603.8	606.9
Core Average	574.2	574.6	577.9
Vessel Average	571.5	571.5	574.7
Vessel/Core Inlet	542.2	539.2	542.5
Steam Generator Outlet	541.9	538.9	542.2
Steam Generator			
Steam Temperature, °F	512.7	498.9	502.4
Steam Pressure, psia	762	674	696
Steam Flow, 10^6 lb/hr total	13.26	13.23	13.24
Feed Temperature, °F	427.4	427.4	427.4
Moisture, % max.	0.10	0.10	0.10
Tube Plugging Level (%)	0	24	24
Zero Load Temperature, °F	547	547	547
Hydraulic Design Parameters			
Mechanical Design Flow, gpm/loop		99,100	
Tech Spec Minimum Measured Flow, gpm total		375,600	
Minimum Measured Flow used in analyses (lowest in core design analysis), gpm total		330,800	

Notes:

1. Conservatively bounds the MUR uprate value of 3067.4.

Table 2.1-2

Design Power Capability Parameters
IP3 3216 MWt(4)

Thermal Design Parameters	Case 1	Case 2	Case 3	Case 4
NSSS Power %	100	100	100	100
MWt	3230(5)	3230(5)	3230(5)	3230(5)
10^6 Btu/hr	11,021	11,021	11,021	11,021
Reactor Power MWt	3216	3216	3216	3216
10^6 Btu/hr	10,973	10,973	10,973	10,973
Thermal Design Flow, loop gpm	88,600(9)	88,600(9)	88,600(9)	88,600(9)
Reactor 10^6 lb/hr	138.8	138.8	134.8	134.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass, %	5.5/7.5(2,10)	5.5/7.5(2,10)	5.5/7.5(2,10)	5.5/7.5(2,10)
Reactor Coolant Temperature, °F				
Core Outlet	584.2/585.5(10)	584.2/585.5(10)	606.2/607.5(10)	606.2/607.5(10)
Vessel Outlet	580.7	580.7	603.0	603.0
Core Average	551.8/552.6(10)	551.8/552.6(10)	575.1/575.8(10)	575.1/575.8(10)
Vessel Average	549.0	549.0	572.0	572.0
Vessel/Core Inlet(12)	517.3	517.3	541.0	541.0
Steam Generator Outlet(12)	517.0	517.0	540.7	540.7
Steam Generator				
Steam Temperature, °F	484.6	480.2	509.7(6)	505.4
Steam Pressure, psia	591(3,13)	567(3,13)	743(3,6)	715(3)
Steam Flow, 10^6 lb/hr total	13.15/13.94(8)	13.14/13.93(8)	13.20/13.99(6,8)	13.18/13.98(8)
Feed Temperature, °F	390/433.6	390/433.6	390/433.6	390/433.6
Moisture, % max.	0.10	0.10	0.10	0.10
Tube Plugging Level (%)	0	10	0	10
Zero Load Temperature, °F	547	547	547	547

Table 2.1-2 (Cont.) Design Power Capability Parameters IP3 3216 MWt	
Hydraulic Design Parameters	
Pump Design Point, Flow (gpm)/Head (ft.)	89,700/272
Mechanical Design Flow, gpm per loop	101,300[11]
Tech Spec Thermal Design Flow, gpm total (TDF Proposed as new Tech Spec consistent with MMF relocated to COLR according to TSTF-339)	354,400
Minimum Measured Flow[7] used in all analyses, gpm total (MMF being relocated from Tech Specs to COLR consistent with TSTF-339)	364,700[1,7]

Notes:

1. Fuel features include: I-Spring ZIRLO mid grids, improved IFMs, and protective bottom grid (see Section 7.0).
2. Core bypass flow has been increased to the range of 5.5 to 7.5% to cover the fuel features.
3. 17 psi steam generator internal pressure drop is incorporated.
4. For the current plant design basis, see Table 2.1-1.
5. RCP heat addition of 14 MWt is included.
6. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure of 787 psia, steam temperature of 516.3°F, and steam flow of 14.01×10^6 lb/hr should be assumed. This envelopes the possibility that the steam generator could perform better than expected.
7. Minimum measured flow (MMF) is based on 2.9% flow measurement uncertainty.
8. Steam flow is affected by the two different feedwater temperatures.
9. TDF supports 10% SGTP based on current plant flow measurements.
10. Core outlet and core average temperatures are affected by the two different core bypass values
11. MDF is increased to provide margin.
12. Actual operation of IP3 is limited to a minimum T_{cold} of 525°F to support the vessel integrity calculations (see subsection 5.1.2).
13. Steam pressure is limited to 650 psia to avoid violation of the steam generator primary-to-secondary pressure differential limit of 1700 psid.

3.0 NUCLEAR STEAM SUPPLY SYSTEM AND AUXILIARY EQUIPMENT DESIGN TRANSIENTS

This section discusses the generation of the Nuclear Steam Supply System (NSSS) and auxiliary equipment design transients for the stretch power uprate (SPU) power conditions. Current NSSS design transients were analyzed for their continued applicability at SPU power, and the resulting transient curves were provided to all system and component designers for use in their specific analyses. Section 3.1 describes the evaluation performed. Auxiliary equipment design transients were also evaluated to determine whether they remain applicable for use in the SPU analysis of all the auxiliary equipment in the NSSS. The results of this evaluation are presented in Section 3.2 of this report.

3.1 Nuclear Steam Supply System Design Transients

3.1.1 Introduction

As part of the original design and analyses of the Nuclear Steam Supply System (NSSS) components for Indian Point Unit 3 (IP3), NSSS design transients (that is, temperature and pressure transients) were specified for use in the analyses of the cyclic behavior of the NSSS components. These were later revised to encompass the replacement steam generator (RSG) in the 1986 to 1988 timeframe. A limited number of them were revised for the 1.4-percent measurement uncertainty recapture (MUR) Uprate Program in 2001. To provide the necessary high degree of integrity for the NSSS components, the transient parameters selected for component stress analyses were based on conservative estimates of the magnitude and frequency of the temperature and pressure transients resulting from various plant operating conditions. The transients selected for use in component stress analyses were representative of operating conditions that could occur during plant operations and were considered to be sufficiently severe or frequent to be of possible significance to component stress analysis. The transients were selected to be conservative representations of transients that, when used as a basis for component stress analysis, would provide confidence that the component was appropriate for its application over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

3.1.2 Input Parameters and Assumptions

NSSS design transients are based primarily on the NSSS design parameters as discussed in Section 2 of this report. The NSSS design parameters, upon which the existing NSSS design transients were based, were compared to the NSSS parameters for the SPU and shown to be noticeably different. The differences were primarily due to:

- The SPU is implementing a T_{avg} window (549° to 572°F)
- The SPU is implementing a feedwater temperature window (390° to 433.6°F)

The NSSS design transients were revised to reflect the changes to the NSSS parameters.

3.1.3 Description of Analyses and Evaluations

The NSSS parameters for the original plant power level and for the SPU power level were compared and it was noted that the incorporation of the T_{avg} operating window and the feedwater temperature window required changes in the existing design transients. In addition, the IP3 Model 44F steam generator design includes a primary-to-secondary pressure differential

design limit of 1550 psid. If this was to be maintained, it would require that the minimum steam pressure for full power be set significantly above the NSSS parameter values. To minimize the plant operations impact and to result in the maximum operating flexibility, this primary-to-secondary pressure differential design limit was increased to 1700 psid (See Section 5.7). This is the same value that has been incorporated in the similar Indian Point Unit 2 (IP2) Model 44F steam generators.

The NSSS parameters for 3230-MWt NSSS power level conditions were used in the design transient development. The resulting plant operating conditions used in the design transient development are shown in Table 3.1-1.

The design transients were redeveloped for the IP3 SPU operating conditions and have been used in the NSSS component and fatigue analyses and evaluations presented in Section 5 of this report.

The NSSS design transients are developed for stress analyses of the various NSSS components. Conservatism is generally included in them via the analysis assumptions associated with either the frequency of occurrence or the transient assumptions. These include:

- Frequencies of occurrence are developed in a conservative fashion. For example, while the plants are operated in a base-loaded fashion, it is assumed that every day a plant loading from 0- to 100-percent power followed by an unloading from 100- to 0-percent power occurs. For the upset transients, it is assumed a reactor trip from 100-percent power occurs 400 times over the plant life (that is, 10 times each year for every year of operation). A loss-of-load is assumed to occur 80 times over the plant life (that is, 2 times each year for 40 years of operation). These transient occurrences are conservative in comparison to actual plant operating experience.

- Conservatisms are taken in the transient analysis assumptions. For example, the normal condition design transients are analyzed assuming they are all at beginning-of-core life (BOL) conditions with conservatively low nuclear reactivity feedback parameters, resulting in the minimum reactivity feedback and maximum parameter (for example, Reactor Coolant System [RCS] and pressurizer pressure and temperature) transient variations. The loss-of-load transient is analyzed like a conservative anticipated transient without scram (ATWS) event, with no reactivity feedbacks, no credit for any control systems, and no reactor trip until the pressurizer is nearly water-solid. The reactor trip transient is assumed to occur at BOL core conditions to result in the minimum decay heat and the maximum RCS cooldown.

The SPU also includes a feedwater temperature window between 390° and 433.6°F for full-power operating conditions.

3.1.4 Acceptance Criteria

There are no specific acceptance criteria for the design transients. See Section 5 for component criteria.

3.1.5 Results and Conclusions

The design transient parameter history curves and tabular data were provided to the various component analysts for their use in assessing the component stresses and cumulative fatigue usage factors. See Section 5 of this report for component results and conclusions.

Table 3.1-1
Operating Conditions for Existing Design Transients vs. SPU Values

Parameter	Present Design	SPU	
		High T_{avg}	Low T_{avg}
T_{hot}, °F	600.8	603.0	580.7
T_{cold}, °F(1)	541.9	540.7	517.0
T_{steam}, °F	512.7	505.4(2)	494.9(3)
P_{steam}, psia	762	715(2)	650(3)
T_{feed}, °F	427.8	433.6 / 390	433.6 / 390

Notes:

1. Steam generator outlet; reactor vessel/core inlet is 0.3°F higher.
2. Values are for the maximum steam generator tube plugging (SGTP) condition; these bound the 0% SGTP conditions for design transient development.
3. Values are minimum full-power steam pressure (and corresponding temperature) to avoid violating the steam generator primary-to-secondary pressure differential limit of 1700 psid.

3.2 Auxiliary Equipment Design Transients

3.2.1 Introduction

The Indian Point Unit 3 (IP3) auxiliary equipment design specifications included transients that were used to design and analyze the Class 1 auxiliary nozzles connected to the Reactor Coolant System (RCS) and certain Nuclear Steam Supply System (NSSS) auxiliary systems piping, heat exchangers, pumps, and tanks. These transients are described by variations in pressure, fluid temperature, and flow and represent umbrella cases for operational events postulated to occur during the plant lifetime. To a large extent the transients are based on engineering judgment and experience and are considered to result in parameter changes of such magnitude, or to occur frequently enough, to be significant in the component design and fatigue evaluation processes. The transients are sufficiently conservative that, when used as a basis for component fatigue analysis, they provide confidence that the component will perform as intended over the operating license period of the plant. For purposes of analysis, the number of transient occurrences was based on an operating license period of 40 years.

As part of the IP3 stretch power uprate (SPU), the auxiliary equipment design transients were reviewed to assess continued applicability.

3.2.2 Input Parameters and Assumptions

The review of the auxiliary equipment design transients was based on the range of NSSS design parameters listed in Table 2.1-2 of this report. The approved range of NSSS design parameters for the SPU was compared with the current NSSS design parameters listed in Table 2.1-1 of this report.

3.2.3 Description of Analyses and Evaluation

An evaluation of the current design transients was performed to determine which transients could be affected by the SPU. The evaluation concluded that the only design transients that could be affected by the SPU are those temperature transients affected by full-load RCS design temperatures.

These temperature transients are defined by the differences between the temperature of the coolant in the RCS loops and the temperature of the coolant in the auxiliary systems connected to the RCS loops. The greater the temperature difference, the greater the effect these temperature transients have on auxiliary component design and stress evaluation. Since the operating coolant temperatures in the auxiliary systems are not affected by SPU, the

temperature difference between the coolant in the auxiliary systems and the coolant in the RCS loops is only affected by changes in the RCS operating temperatures.

The current design temperature transients are based on a full-load T_{hot} of 630°F and a full-load T_{cold} of 560°F. These full-load temperatures were assumed for equipment design to ensure that the temperature transients would be conservative for a wide range of NSSS design parameters.

3.2.4 Acceptance Criteria and Results

A comparison of the range of NSSS design temperatures for an SPU at full-load, that is T_{hot} (580.7° to 603.0°F) and T_{cold} (517.3° to 541.0°F) with the T_{hot} and T_{cold} values used to develop the current design transients, indicates that the SPU temperature ranges are lower. These lower full-load operating temperatures result in less severe transients since the temperature differences are lower between RCS loop temperatures and the lower operating temperatures in the auxiliary systems connected to the RCS. For example, the temperature transients imposed on the Chemical and Volume Control System (CVCS) letdown and charging nozzles associated with starting and stopping letdown and charging flow would be less severe since the temperature differences are less. Therefore, the current body of auxiliary design transients is conservative for the proposed SPU.

3.2.5 Conclusions

The only auxiliary equipment transients that can be potentially affected by the SPU are those temperature transients related to full-load NSSS design temperatures. A review of these temperature transients indicates that if these transients were based on the SPU design parameters, they would be less severe. Therefore, the current auxiliary equipment design transients for IP3 remain bounding for the proposed IP3 SPU.

4.0 NUCLEAR STEAM SUPPLY SYSTEM

This section describes the evaluation of the Nuclear Steam Supply System (NSSS) fluid systems that support the stretch power uprate (SPU). Evaluations and analyses were performed to confirm that the NSSS fluid systems continue to perform their intended functions under the SPU conditions. The systems addressed in this section are as follows:

Fluid Systems:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Emergency Core Cooling System (ECCS) (Safety Injection System [SIS]/Containment Spray System [CSS])
- Primary Sampling System (PSS)
- Component Cooling Water System (CCWS)
- Spent Fuel Pit Cooling System (SFPCS)

Results and conclusions are presented within each subsection.

4.1 Nuclear Steam Supply System Fluid Systems

Introduction

This section of the report evaluates the Nuclear Steam Supply System (NSSS) fluid systems for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions. The plant NSSS design data to be evaluated for both the current plant conditions and the SPU power levels are presented in Tables 2.1-1 and 2.1-2, respectively. The data in Table 2.1-2 were evaluated for the SPU.

This report section addresses the following NSSS systems:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Emergency Core Cooling System (ECCS)
  - Safety Injection System (SIS)
  - Containment Spray System (CSS)
- Primary Sampling System (PSS)
- Component Cooling Water System (CCWS)
- Spent Fuel Pit Cooling System (SFPCS)

The fluid systems evaluations described in this section were performed at the system level. Evaluations of the NSSS components are described in Sections 5.1 through 5.10 of this report.

4.1.1 Reactor Coolant System

The changes in NSSS design parameters that affect the RCS design bases functions include the increase in core power and the allowable range for average RCS temperature (T_{avg}). Verification that the major RCS components can support these changes is addressed in Sections 5.1 through 5.10 of this report. The increase in core power and the allowable RCS T_{avg} range also affect the duty placed on the RCS control and protection systems. Verification that the RCS control and protection systems can support the SPU is addressed in Section 4.3 of this report. This section of the report discusses the RCS fluid system design. The system design

considerations include the pressurizer surge line, safety valves inlet and discharge piping, pressurizer relief tank (PRT), power-operated relief valve (PORV) inlet and discharge piping, pressurizer spray subsystem, and RCS instrumentation setpoints (excluding instrument channels used by the control and protection systems).

RCS Design Parameters

The NSSS design parameters at the SPU power level are shown in Table 2.1-2. The revised parameters that affect RCS performance are core power and the resulting full-load T_{cold} and T_{hot} temperatures. The steady-state RCS pressure (2235 psig) and no-load RCS temperature (547°F) have not changed. The changes in full-load RCS temperatures are shown below:

RCS Temperatures	1.4% MUR Parameters	SPU Parameters
T_{cold} (SG Outlet)	541.9°F	517° to 540.7°F
T_{hot} (Vessel Outlet)	600.8°F	580.7° to 603.0°F

These uprate parameters are based on a T_{avg} window of 549° to 572°F. (The 1.4-percent measurement uncertainty recapture [MUR] uprating T_{avg} was 571.5°F.)

RCS Design Temperature and Pressure

The RCS is specified with a design pressure of 2485 psig and a nominal operating pressure of 2235 psig. The RCS design temperature is 650°F with the exception of the pressurizer, which is designed to 680°F. Based on the SPU RCS parameters, the RCS design pressure and temperature continue to bound the uprated operating conditions.

The RCS transient operating conditions and associated RCS overpressure evaluations resulting from the RCS and plant transients are discussed in other sections of this report, as follows:

- RCS pressure control via the pressurizer heaters and spray systems, including the capability of the surge line, spray valves, and associated instrumentation and setpoints is discussed in Section 4.3.
- RCS inventory control via the pressurizer level control systems, including the associated instrumentation and setpoints is discussed in Section 4.3.
- RCS temperature control, including the associated instrumentation, is discussed in Section 4.3.

- Protection system actuation, including the associated instrumentation and setpoints, is discussed in Section 6.10.

- RCS piping analyses, based on the SPU operating conditions, are discussed in Section 5.4.

Therefore, it is concluded that the RCS design temperature and pressure are not affected by the uprated conditions, and the design of the RCS pressure boundary is maintained within the original design limits.

RCS Heat Capacity

The RCS heat capacity is defined as the amount of heat (in Btus) required to raise or lower the RCS temperature by one degree Fahrenheit (Btu/°F), or, the amount of sensible heat that must be removed or added to the RCS for a given change in RCS temperature. The RCS heat capacity is derived from the composite of the RCS fluid(s) and the component masses. RCS component mass is not changing while the SPU change in RCS fluid mass is insignificant.

Therefore, it is concluded that the RCS heat capacity is not affected by the SPU.

Reactor Coolant Pump Net Positive Suction Head

This section addresses reactor coolant pump (RCP) net positive suction head (NPSH) and the Residual Heat Removal System (RHRS) suction valves open-permissive interlock, as it relates to RCS flow. Adequate RCP NPSH, at the RCP suction, is monitored by using the RCS wide-range pressure instrument. This same pressure transmitter also provides an input signal to the RHRS suction valves open-permissive interlock. Since the RCS wide-range pressure instrument tap is somewhat removed from the RCP suction point (the wide-range pressure instrument is located in the RCS hot leg), the pressure drop from the RCS wide-range pressure transmitter to the RCP suction must be included when using this instrument for monitoring RCP NPSH. This pressure drop is a function of RCS flow, in addition to other plant physical parameters such as RCS component and piping losses. The RCP NPSH and RHR open permissive interlock were evaluated for SPU RCS flow conditions (for the SPU fuel considered at this time) and remain acceptable for the SPU conditions.

Therefore, it is concluded the RCP NPSH and RHR open permissive interlock are acceptable for the SPU.

Pressurizer Spray Flow

The pressurizer spray flow is used for RCS pressure control. The driving head for pressurizer spray is the pressure difference from the reactor coolant loop (RCL) spray nozzle to the RCL surge nozzle and is a function of RCS flow and temperature. Since the changes in RCS temperatures are small at the SPU conditions, there is no effect on pressurizer spray performance as a result of the RCS temperature changes at SPU conditions. The RCS flow for the SPU conditions is greater than the flow assumed in the spray performance analysis.

Therefore, it is concluded that acceptable spray flow is provided at the SPU conditions.

Pressurizer Spray and Surge Line Low-Temperature Alarms

The pressurizer surge line and pressurizer spray line temperature instruments are provided to indicate that the minimum spray and surge line flows are met, so that thermal shock to these lines is minimized when these lines are in use. Since the changes in SPU no-load and minimum full-power RCS hot and cold leg temperatures are very small, the nominal 500°F setpoints of these instruments are not affected by the SPU conditions.

Therefore, it is concluded that acceptable low temperature alarms are provided at the SPU conditions.

Pressurizer Relief Tank

The PRT is designed to accept and quench the design basis discharge from the pressurizer steam space. The PRT is conservatively sized to condense and cool a discharge of steam equivalent to 110 percent of the full-power pressurizer steam volume for the loss-of-load/turbine trip analysis. The amount of energy absorbed by the PRT is related to the volume and pressure of the steam discharged. As indicated in Table 2.1-2, RCS pressure has not changed for the SPU conditions. However, pressurizer level has changed (lower) at the SPU conditions for the full T_{avg} window considered, and was evaluated for the PRT. The sizing/design basis mass released to the PRT is not exceeded since there is no complete filling of the pressurizer permitted for the SPU loss-of-load/turbine trip analysis. The current design basis for the PRT bounds the SPU loss-of-load/turbine trip analysis mass addition, such that the PRT continues to meet its design basis mass addition, without any changes in the current PRT setpoints.

Therefore, it is concluded that acceptable PRT performance is provided at the SPU conditions, without any changes in the current PRT setpoints.

RCS Net Heat Input

The RCS net heat input was determined for the SPU to be 12.6 MW. This value reflects the net heat input for the daily calorimetric at the SPU conditions and justifies the conservative 14 MW used in the various SPU analyses using net heat input for full-power operation.

Therefore it is concluded that conservative RCS net heat input parameters, based on SPU conditions, were used for the SPU analyses.

4.1.2 CVCS

The changes in NSSS design parameters that could potentially affect the CVCS design bases functions include the increase in core power and the allowable range for RCS full-load design temperatures. The increase in core power and the allowable range for RCS full-load design temperatures may also affect the CVCS design bases requirements related to the core re-load boron requirements. Additionally, the allowable range for RCS full-load design temperatures may affect the heat loads that the CVCS heat exchangers (HXs) must transfer to the CCWS, and in the case of the regenerative HX, to the charging flow.

Regenerative Heat Exchanger

The regenerative HX cools the normal letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 555°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F (see Table 2.1-2). The no-load RCS temperature has not changed, while the full-load SPU T_{cold} temperature has decreased by a small amount. The performance of the regenerative HX (that is, less limiting, slightly decreased charging and letdown temperatures) is acceptable at SPU conditions with the minor change in letdown flow (due to the small change in RCS T_{cold} temperature).

Therefore it is concluded that acceptable regenerative HX performance is provided at the SPU conditions, with no plant changes required.

Non-Regenerative Heat Exchanger

The non-regenerative HX cools the letdown flow from the regenerative HX. Since the change in performance of the regenerative HX is less limiting at SPU conditions, as discussed in the previous section, there will be a small (less limiting) effect on the performance of the non-regenerative HX. The minor difference in performance (decreased cooling water flow) can

easily be accommodated within the capability of the non-regenerative HX cooling water temperature control valve, AC-TCV-130.

Therefore it is concluded that acceptable non-regenerative HX performance is provided at the SPU conditions, with no plant changes required.

Excess Letdown Heat Exchanger

The excess letdown HX cools the excess letdown flow from the RCS, which is at RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the excess letdown HX is 555°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of 547°F. Since the no-load RCS temperature has not changed, and the full-load SPU T_{cold} temperature has decreased by a small amount, the performance of the excess letdown HX is acceptable at SPU conditions with the change in RCS T_{cold} temperature.

Therefore it is concluded that acceptable excess letdown HX performance is provided at the SPU conditions, with no plant changes required.

Seal Water Heat Exchanger

The seal water HX cools the seal return flow from the four RCP No. 1 seals and the excess letdown flow (from the excess letdown HX) if it is in service. The RCP heat load (including the thermal barrier HX) is a function of RCS T_{cold} temperature, while the excess letdown heat load is a function of excess letdown HX performance. Since the no-load RCS temperature has not changed, and the full-load SPU T_{cold} temperature has decreased by a small amount, the performance of the seal water HX is acceptable at SPU conditions with the change in RCS T_{cold} temperature.

Therefore it is concluded that acceptable seal water HX performance is provided at the SPU conditions, with no plant changes required.

Charging, Letdown, and RCS Make-Up (Boration, Dilution, and N-16 Delay Time)

As discussed in the above sections for the various CVCS HXs, there are minor (lower temperatures) effects on their performance at the SPU conditions. Therefore, there will also be very small flow effects on the charging (including RCP seal injection) and letdown performance provide by the CVCS that the plant can easily adjust to. The flow capacity performance of the RCS make-up system is independent of the change in RCS conditions resulting from the SPU conditions. However, the make-up system also relies on storage capacity of various sources of

water including primary make-up water and boric aid solutions from both the boric acid storage tanks and the refueling water storage tank (RWST).

Primary make-up water is used to dilute RCS boron, to provide positive reactivity control or to blend concentrated boric acid to match the prevailing RCS boron concentration during RCS inventory make-up operations. Since the flow capacity performance of the RCS make-up system is independent of the change in RCS conditions resulting from the SPU conditions as discussed above, the SPU does not affect the capability of the make-up system to perform these system functions.

The boric acid storage tanks and RWST provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The SPU is expected to have a small effect on the boration requirements that must be provided by the CVCS boration capabilities. The maximum expected RCS boron concentrations are within the capability of the CVCS. The Westinghouse reload safety evaluation (RSE) process (Reference 1) is designed to address boration capability for routine plant changes, such as core reloads, and infrequent plant changes such as a plant uprating that result in a change to core operating conditions and initial core reactivity. Therefore, boration capability will be addressed during the RSE process for each reload cycle.

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. Since the change in letdown flow is very small, as discussed in the previous paragraphs, this radiation protection feature of the CVCS is not affected by the SPU. However it is noted that the letdown line and excess letdown line radiation dose rates from N-16 (for example, amount of N-16) will slightly increase proportional to the increase in reactor power level.

Therefore, it is concluded the CVCS charging, letdown and RCS makeup performance is acceptable at the SPU conditions, considering the following points:

- The boration capability will be addressed during the Reference 1 RSE process for each reload cycle

- There will be a small increase in letdown line dose rates from N-16, proportional to the slight increase in reactor power level

4.1.2.1 Primary Chemistry Control

The changes in plant parameters that affect the primary chemistry program for IP3 were evaluated for SPU conditions. As noted in the NSSS parameters (Table 2.1-2 of this document), the range of vessel average temperature (T_{avg}) extends from 549° to 572°F; the range of T_{hot} extends from 580.7° to 603.0°F for the SPU. The best-estimate T_{avg} is expected to be 567°F. The RWST maximum boron concentration is listed in the IP3 *Improved Technical Specifications* (ITS) (Reference 2) as 2600 ppm. No change in RCS pH control is being recommended for the SPU. The design parameters (Table 2.1-1 of this document) for the 1.4-percent MUR Program provided an RCS T_{avg} of 571.5°F and T_{hot} of 600.8°F with no SGTP.

The chemistry of the NSSS is usually considered to be the chemical composition of the primary coolant and the secondary coolant, and the chemistry programs are designed to keep concentrations of various chemicals within industry-accepted guidelines. These guidelines were prepared by a committee of industry experts and reflect field and laboratory data on primary coolant system corrosion and performance issues. Chemicals present include those purposely added for corrosion and pH control, contaminants, and boric acid added as a chemical shim on the primary side.

The IP3 SPU results in relatively small temperature changes in primary and secondary coolant temperatures, and these new operating conditions are well within the envelope of conditions used in developing the industry chemistry guidelines.

Therefore, it is concluded the IP3 plant chemistry limits based on industry guidelines remain acceptable at the IP3 SPU conditions, and no changes to the primary chemistry program are required for the IP3 SPU.

4.1.3 Residual Heat Removal System

The higher SPU power level results in an increase in the amount of residual heat being generated in the core during normal cooldown, refueling operations and accident conditions. This provides a higher heat load on the residual HXs during the cooldown and also during the refueling outage. The removal of core decay heat for accident conditions is also addressed in other parts of Section 4 below and in Section 6 of this report. The increased heat loads will be transferred to the Component Cooling Water System (CCWS) and ultimately to the Service Water System (SWS). Evaluation of the SPU performance of the RHRS in conjunction with the CCWS and SWS with the increased heat loads is addressed in this subsection and in subsections 4.1.6 and 9.6 of this report.

The SPU affects the plant cooldown time(s) since core power, and therefore the decay heat increases. The plant cooldown calculation was performed at a core power of 3216 MWt to support the SPU. The RCS heat capacity and the other RHR heat loads were explicitly considered in these analyses. The analysis was performed to confirm that the RHR and CCW systems continue to meet their design basis functional requirements and performance criteria for plant cooldown under the uprated power conditions. The two-train system alignment was considered to address the design capability in the *Indian Point Unit 3 Updated Final Safety Analysis Report* (UFSAR) (Reference 3). In addition, a cooldown analysis was performed to support the worst-case scenario for the 10CFR50 Appendix R (Reference 4) fire hazards and safe shutdown analysis.

The following considerations were applied to these cooldown analyses:

- The CCW and RHR HX data assumes 5-percent tube plugging, as was used for the previous cooldown analyses of record (AOR). This results in slightly degraded normal cold shutdown and Appendix R cooldown performance.

- The design service water temperature of 95°F was assumed. For normal cooldown, the CCWS supply temperature is limited to 120°F, while for Appendix R cooldown, the CCWS supply temperature is limited to 125°F.

- Various CCWS auxiliary heat loads and the RCS heat capacity were included in the normal cooldown cases and the Appendix R plant cooldown case. These heat loads, along with an increase in the spent fuel pool heat load (assuming a full SFP of fuel that has operated at 3216 MWt) were used in the cooldown analysis.

- Decay heat curves based on 24-month fuel cycles were used.

- Service water (SW) flow rates for Appendix R cooldown were varied to minimize SW flow demand while meeting the Appendix R criteria as shown in Table 4.1-1.

As shown by the results summary in Table 4.1-1, the normal plant cooldown time to 140°F with both trains of CCW and RHR available increased from 94.1 hours for the 1.4-percent MUR to 105 hours for the SPU. The normal plant cooldown time to 200°F with both trains of CCW and RHR available increased from 17 hours for the 1.4-percent MUR to 21 hours for the SPU. The primary reason for this is the uprated core power and the corresponding increase in the SFP auxiliary heat load on the CCWS. Since there is no design criterion for normal plant cooldown time, these increases in calculated values, based on design conditions, are acceptable.

The Appendix R/safe shutdown cases continue to meet the 72-hour time limit for cold shutdown. For these cases, the minimum CCW HX service water flow to meet the time 72 hour cooldown time limit criterion was determined as shown in Table 4.1-1.

It is concluded that acceptable RHR cooldown performance is provided at the SPU conditions for normal plant cooldown and the limiting Appendix R/safe shutdown cases, based on the service water flows shown in Table 4.1-1.

4.1.4 Emergency Core Cooling System (SIS/CSS)

The required volume, duration, and heat rejection capability of the Safety Injection System (SIS) and Containment Spray System (CSS) flows in the event of a postulated accident were determined based on analytical and empirical models that simulate reactor and containment conditions subsequent to the postulated RCS and Main Steam System (MSS) breaks. As a result of these analyses, the system and component criteria necessary to demonstrate compliance with regulatory requirements at the SPU power level were established. Since the results of these analyses (see Section 6 of this report) have demonstrated that SIS and CSS provide adequate safety margin, the SIS and CSS are acceptable for the SPU conditions.

The scope of this discussion regarding the ECCS includes the SIS (both low-head and high-head systems) and the CSS performance. Subsequent to ECCS and CSS actuation, the SIS draws water from the RWST during the injection phase and delivers it to the RCS, while the CSS simultaneously draws from the RWST and sprays the containment atmosphere. At the conclusion of RWST draindown, operation of the CSS is terminated. Also at the conclusion of RWST draindown, the SIS is switched to the containment recirculation alignment, drawing fluid from the containment sump. The SIS can also provide recirculation spray to the CSS, if required for continued containment cooling, during the recirculation phase.

Minimum and maximum containment spray flows from the RWST were calculated for the SPU. These spray flows were used in the SPU containment accident analyses. 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 term recirculation phase. The SPU accident analyses are discussed further in Section 6 of this report.

As a result of the SPU requiring higher HHSI hot leg flows, the HHSI system was modified by permanently closing two cold leg branch lines, and throttling the high head safety injection system to provide higher cold leg and hot leg flows. Also, system changes were made to enhance spilling line performance for the LOCA analysis. The HHSI system performance

analysis also considered the recirculation sump particle criteria and the system throttle valve cavitation issues.

As a result of the SPU requiring higher LHSI cold leg recirculation flows, the LHSI system operation was modified for the recirculation phase of operation. Re-throttling of the LHSI system butterfly valves (via revised EOP setpoints) provides the higher LHSI cold leg flows (while also providing the required recirculation spray flow).

There could be a small effect (a slight increase in sump fluid temperature) during recirculation since decay heat slightly increases (with power level). The post-loss-of-coolant accident (post-LOCA) containment sump temperature performance along with changes (increases) in recirculation flow have been addressed for the RHR HX tube side, and it is concluded that acceptable RHR HX temperature and flow performance is obtained.

It is concluded that the flow performance of CSS, HHSI and LHSI systems determined for the SPU are acceptable. The post-LOCA recirculation flow and temperature performance of the RHR HX is also acceptable based on the SPU sump temperature results.

4.1.5 Primary Sampling System

The change in NSSS design parameters that potentially affect the Primary Sampling System (PSS) design bases is the allowable range for average RCS design temperature (T_{avg}). The PSS provides fluid samples from the RCS (pressurizer and hot leg) for laboratory analysis. The sample flows from the RCS are cooled (pressurizer steam samples condensed and cooled) via HXs. Since the SPU alters RCS loop operating temperatures, the PSS HXs were evaluated to assess the effect on the design duty of these HXs.

The scope of this evaluation is limited to the high-pressure, remotely obtained samples from the RCS since these sample locations set the limiting process conditions that govern the design of the PSS and associated sample coolers. The PSS is discussed in Section 9.4 of the UFSAR (Reference 3). The limiting duty for the RCS sample coolers is based on the capability of the cooler to condense and cool a sample stream from the pressurizer steam space. The maximum normal steam condition within the pressurizer is based on the saturation steam temperature (653°F) at normal operating RCS pressure, since the pressurizer is maintained at saturation conditions for RCS pressure control. As discussed in the RCS section above, the RCS operating pressure has not changed at the SPU conditions. Therefore, the design duty of the PSS is not affected as a result of the SPU.

It is concluded the PSS design bounds the SPU operating conditions and therefore is not affected as a result of the SPU.

4.1.6 Component Cooling Water System

The CCWS is an intermediate system between the various radioactive fluid systems and the Service Water System (SWS). It ensures that radioactivity leakage from the components being cooled is contained within the plant. Revised heat rejection rates and cooling water flow requirements were assessed for the SPU.

Normal Plant Operations (at-Power and Refueling)

The design bases of the CCWS for IP3 are described in the Section 9.3 of the UFSAR (Reference 3). The plant heat loads on the CCWS are as follows:

- RHR HXs
- Charging pumps (bearing and fluid-drive oil coolers)
- Seal water HX (RCP no. 1 seal-leak off return and excess letdown)
- Non-regenerative HX
- Primary sample HX (pressurizer steam, pressurizer liquid, RCS)
- Steam generator blowdown sample HX
- Radiation monitor condenser sample cooler
- Excess letdown HX (during plant heatup)
- Reactor vessel support cooling blocks
- RCP motor-bearing oil coolers (upper and lower)
- RCP thermal barrier HX
- SFP HX
- Waste gas compressors (seal water cooling and seal water make-up)
- Residual heat removal (RHR) pumps
- SI pumps
- Recirculation pump motors

As noted in Section 2, the NSSS at-power parameters (T_{hot} and T_{cold}) both hot and cold leg temperatures go down at full power and the no-load T_{avg} remains unchanged. The initial containment temperature limit (130°F) remains unchanged. Of the CCWS heat loads discussed above, the SFP is the only heat load with a potential to affect the CCWS during normal plant operation. The interaction of the SFPCS and the CCWS is addressed in subsection 4.1.7 for normal plant operation and refueling. All other heat loads are not affected by the SPU during normal (at-power) plant operation.

Therefore, it is concluded the CCWS is not affected by the SPU during normal power operation, except for the effects of the SFPCS, addressed in subsection 4.1.7 for normal plant operation.

Normal and 10CFR50 Appendix R (Fire Protection) Plant Cooldown

The CCWS provides cooling to the RHR HXs during plant cooldown. (See subsection 4.1.3 for discussion of plant cooldown performance.) During plant cooldown, the RHR HX heat load is controlled by throttling RCS flow so that an acceptable CCWS supply temperature is maintained to the CCWS-serviced equipment. Based on the results of the updated RHR cooldown work described in subsection 4.1.3, the historical CCWS supply temperature limits have been maintained for the SPU. For normal cooldown, the CCWS supply temperature is limited to 120°F, while for Appendix R cooldown, the CCWS supply temperature is limited to 125°F.

Therefore, it is concluded that CCWS operation during plant cooldown is acceptable for the SPU because the RHR cooldown analyses show acceptable cooldown time results with the above CCW supply temperature limits.

Post-LOCA Plant Cooldown

The CCWS supports post-LOCA ECCS operation during recirculation by providing cooling to the RHR HXs. There could be a small effect (a small increase in sump fluid temperature) during recirculation since decay heat slightly increases with reactor power level. The post-loss-of-coolant accident (post-LOCA) containment sump temperature performance along with changes (increases) in recirculation flow have been addressed for CCW cooling to the RHR HXs, and it is concluded that acceptable RHR HX CCW temperature performance is obtained.

It is concluded that the post-LOCA and CCW temperature performance of the RHR HX is acceptable based on the SPU recirculation flow and sump temperature results.

4.1.7 Spent Fuel Pit Cooling System

Spent Fuel Pit Cooling System Performance during Normal Plant Operation

The SPU affects the SFPCS performance since core power, and therefore the decay heat of the fuel assemblies increases. The SFPCS performance calculation supports the SPU core power of 3216 MWt. The analysis was performed to confirm that the SFPCS and CCWS continue to meet their design basis functional requirements and performance criteria for plant cooldown at the SPU power conditions.

The following assumptions were applied to the SFPCS performance analysis:

- The SFPCS and CCW heat exchanger data assumes 5-percent tube plugging.

- All SFP fuel was assumed to have operated at the SPU reactor power of 3216 MWt to provide a conservative bounding basis for the SFP decay heat load.

- Decay heat curves were based on 24-month fuel cycles.

- The analysis evaluated the capability of the SFPCS and the CCWS to cool the SFP based on SW temperatures of 70° and 95°F.

The SFP maximum normal heat load is 17.6 MBTU/hr. This is based on 20 days elapsed time since the previous shutdown with the maximum number of fuel assemblies in the SFP while still having core offload capacity. With the SFP at 150°F, the SFP heat exchanger with 5-percent tube plugging, and 70°F SW, the SFP heat exchanger will remove 27.2 MBTU/hr. With the SFP at 150°F, the SFP heat exchanger with 5 percent tube plugging, and 95°F SW, the SFP heat exchanger will remove 17.6 MBTU/hr.

Therefore, it is concluded that under these conditions, the SFPCS has sufficient heat removal capacity. These heat load results are also used as input for the CCW system auxiliary heat load analyses as appropriate.

Refueling Operation SFPCS Performance

The SFP contains spent fuel discharged from the reactor over its operating life. The SPU affects the SFPCS performance since core power, and therefore, the decay heat of the fuel assemblies increases. Due to the conservatism in the heat load calculations, the assumption of 5-percent plugging of the SFP HX tubes and the remote probability that the maximum allowable SW and CCW temperatures would occur simultaneously and coincident with a refueling offload, a cycle-specific heat load evaluation using the anticipated actual conditions at the time of the offload will be performed prior to each refueling outage. This evaluation, based on expected SW temperature, CCW flow, SFP HX performance capability, supplemental heat removal capability, and reload-specific SFP heat removal requirements will determine the decay time and supplemental cooling capability required so that bulk SFP temperature will remain below 200°F (full-core offload).

If the calculation shows that the SFP temperature will exceed 200°F with supplemental cooling, movement of fuel from the reactor into the SPF will not occur until the fuel has decayed to an acceptable level. The required hold time will be documented in the evaluation. Maintaining the SFP bulk temperature at 200°F or less is consistent with the current operation and design of the SFPCS, as well as the SFP structure itself. Therefore, by administratively controlling the in-core hold time of the fuel after shutdown to ensure that the SFP temperature does not exceed 200°F,

it will not be necessary to make physical or analytical modifications to the SFP or its cooling system as a result of the SPU.

Two criteria must be met before spent fuel can be discharged to the SFP:

- Spent fuel can not be discharged to the SFP until at least 84 hours after shutdown to satisfy the assumptions of the spent-fuel handling accident analysis, as discussed in subsection 6.11.9 of this report.

- An additional delay time limit prior to spent fuel discharge is administratively controlled by operating procedures to ensure that the total spent fuel heat load is within the capacity of the spent fuel cooling loop as augmented by supplemental cooling capability to satisfy the bulk pit water temperature limits discussed above. This is a variable time limit primarily dependant upon SW temperature, and cooling capacity with supplemental cooling.

SFP Criticality

The requirements of 10CFR50.68(b) apply to IP3 and remain valid for the upgrade fuel design. As discussed in Section 7 (Reference 5) of this document, the main changes in the upgrade fuel assembly are grid changes and the grids are not modeled in the 10CFR50.68(b) analyses. Furthermore, the current criticality analyses use Zircaloy/Zirc-4, while the upgrade fuel assembly will use ZIRLO. Since ZIRLO has a slightly higher absorption of neutrons, the current analysis remains bounding.

4.1.7.1 Analysis Methods for Reload-Specific SFPCS Capability Calculations

Calculation of Decay Heat Load in SFP

The calculation of the decay heat load on the SFP will be based on the contents of the SFP at the time of the reload. A census of the actual fuel assemblies in the SFP prior to the offload will be used in conjunction with the decay heat characteristics of the fuel to be placed in the SFP from the core. The heat load will be based on decay time, power history, and inventory of the SFP.

Calculation of Heat Removal Capacity

The calculation of heat removal capacity will be based on parameters that affect cooling capability. The specific inputs to the calculation will be chosen to be representative of the conditions predicted to exist at the time the core offload is scheduled to take place.

Representative values will be chosen for SW temperature, decay heat load in the SFP, SW, and CCW cooling system flow rates, and HX performance parameters (heat transfer area and tube plugging).

The calculation of supplemental heat removal capacity will be based on the excess cooling needed to keep the SFP temperature below 200°F at the time of planned core offload. Representative values will be chosen for SW temperature, decay heat load in the SFP, SW, and CCW cooling system flow rates, and HX performance parameters (heat transfer area and tube plugging). If the combination of SFPCS capability and supplemental cooling capability is not sufficient, then the planned core offload time will be delayed until the combined capacity is sufficient.

A 10-percent uncertainty factor is applied to all calculated heat loads in accordance with the recommendation of Branch Technical Position ASB 9-2 (Reference 6).

Administrative Controls for SFP Cooling Implementation

Administrative controls for SFP cooling implementation will be included in IP3 procedures.

Adequate Make-Up Supply

The make-up needs have been assessed for normal SFP conditions with a maximum number of fuel assemblies that have been operated. The SFP maximum normal heat load is 17.6 MBtu/hr. This is based on 20-days elapsed time since the previous shutdown with the maximum number of fuel assemblies in the SFP while still having core offload capacity. If the SFP were to lose all cooling under these conditions with an initial pool temperature of 150°F, the time to boil would be 4.9 hours. The required make-up for boiloff with this heat load would 60 gpm. Make-up water can be supplied within this time and at this rate from the primary water storage tank (PWST), the RWST, or the Fire Protection System.

The refueling core offload heat load was evaluated for SPU conditions to determine the make-up needs. The evaluation assumed a maximum number of fuel assemblies that have been operated at 3216 MWt. With no heat removal by installed or supplemental cooling capability, the time for the SFP water to rise from 200° to 212°F is at least 33 minutes. The maximum required make-up rate for boiloff is 100 gpm (for a full core offload). Make-up water can be supplied within this time and at this rate from the PWST, the RWST, or the Fire Protection System.

4.1.7.2 Conclusions Regarding Reload-Specific SFPCS Capability Calculations

Because the offload-specific calculations will determine the SFP capability required and such capability will be provided before fuel is offloaded to the SFP, acceptable SFPCS performance will be provided for the SPU conditions. In the event of a total failure of the SFPCS, the SFP heat inertia will allow sufficient time to place make-up water capability into service. The required SFP make-up capability for the most limiting case requires 100-gpm make-up. The make-up water can be supplied within the required time and at this rate from the PWST, the RWST, or the Fire Protection System.

4.1.8 NSSS Evaluation of Generation of and Protection from Missiles

All NSSS rotating equipment remains within its design criteria and therefore, there is no change in the missile analysis or in the protection provisions as a result of the SPU. Any physical plant changes required for the IP3 SPU have not adversely affected the missile protection capability of IP3.

Based on the insignificant changes in system pressure and temperature conditions during plant operation and anticipated operational occurrences as a result of the IP3 SPU, NSSS systems, structures and components important to safety will continue to meet requirements for generation of and protection from internally generated missiles following implementation of the SPU.

It is concluded that the generation of and protection from internally generated missiles is not affected following implementation of the SPU.

4.1.9 References

1. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, F. M. Bordelon et al., July 1985.

2. Indian Point Unit 3 Improved Technical Specifications, Amendment No. 203, License No. DPR-64, Docket No. 50-286.

3. Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report, Rev. 18, Docket No. 50-286.

4. 10CFR50, Appendix R, Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979.

5. NRC Branch Technical Position ASB 9-2, Residual Decay Energy for Light-Water Reactors for Long-Term Cooling (contained in U.S. NRC Standard Review Plan 9.2.5, "Ultimate Heat Sink," Rev. 2, July, 1981.

6. 10CFR50.68, *Criticality Accident Requirements*, November 12, 1998.

Table 4.1-1 SPU Cooldown Analyses Results				
Cases	Cooldown Time to 140°F (hrs. after shutdown)	Cooldown Time to 200°F (hrs. after shutdown)	RHR Initiation Time @350°F (hrs. after shutdown)(1)	Total SW Flow (gpm)
1. Normal Cooldown with CCW Aux Heat Loads	105.0	21	5.0	9100
2. Normal Cooldown without CCW Aux Heat Loads	84.8	14.0	4.0	9100
3. App. R, Enhanced CCW UA/U, 5700 gpm SW Flow	N/A	64.8(2)	29.0	5700
4. App. R, Enhanced CCW UA/U, SW Flow Minimized to Meet 72-hr. Cooldown Time	N/A	71.8	29.0	4700
5. App. R, Original Design SSC UA/U, SW Flow Minimized to Meet 72-hr. Cooldown Time	N/A	71.9	29.0	5324
6. Same as 3 without SFP Heat Load	N/A	58.0(2)	29.0	5700
7. Same as 4 without SFP Heat Load	N/A	71.8	29.0	3596
8. Same as 5. Without SFP Heat Load	N/A	72.0	29.0	3918

Notes:

1. The 29-hour cut-in time for the Appendix R cases, limited by the CCWS supply temperature, is also indicative of the cut-in time assumed in the radiological consequences analyses of accidents with secondary side releases (that is, SGTR).
2. These cases increase the component cooling water return piping temperature compared to the previous 1.4% MUR Appendix R analysis. Previous Appendix R cases had a maximum return temperature of 173°F, and the temperature for Case 6 is 188°F, which remains bounded by post-LOCA conditions.

4.2 NSSS/Balance-of-Plant Interface Systems

The Westinghouse sizing criteria for the Nuclear Steam Supply System/balance-of-plant (NSSS/BOP) interface (Section 6.2 of Reference 1) were originally established to provide guidelines to the BOP designer to ensure that the BOP design would be compatible with the NSSS. Following completion of the BOP designs for each plant, the BOP design parameters and capabilities were then used in the accident and transient analyses to demonstrate that the entire plant design had sufficient capability to accommodate accidents and transients that were postulated. The sizing criteria were checked for each uprate to determine if there is a potential for unacceptable results for accident or transient analyses that constitute the acceptance and licensing criteria for the plant components systems.

As part of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), the following BOP fluid systems were reviewed against the Westinghouse NSSS/BOP interface guidelines:

- Main Steam System (MSS)
- Steam Dump System
- Condensate and Feedwater System (C&FS)
- Auxiliary Feedwater System (AFWS)
- Steam Generator Blowdown System (SGBS)

The review was based on the range of NSSS design parameters approved for an NSSS power level of 3230 MWt (see Section 2 of this report). The current design parameters are those approved for the 1.4-percent measurement uncertainty recapture (MUR) with an NSSS power of 3082 MWt (Section 6.2 of Reference 1). The interface systems were reviewed to determine changes to interface information for use in the more detailed BOP analyses discussed in Section 9 of this report.

A comparison of the SPU design parameters (Table 2.1-2) with the current design parameters (Table 2.1-1) previously evaluated for systems and components indicates differences that could affect the performance of the BOP systems.

Evaluations of the above BOP systems relative to the Westinghouse NSSS/BOP interface guidelines were performed to address the NSSS design parameters for the SPU that include ranges for parameters such as T_{avg} (549° to 572°F), steam generator tube plugging (SGTP) (0 to 10 percent), and feedwater temperature (390° to 433.6°F). These ranges on NSSS design parameters result in ranges on BOP parameters such as steam generator outlet pressure (567 to 787 psia) and steam/feedwater mass flow rates (13.14×10^6 lb/hr to 14.01×10^6 lb/hr) (Table 2.1-2). The NSSS/BOP interface evaluations were performed to address the effect of these NSSS design parameters on the BOP. The results of the NSSS/BOP interface evaluations are discussed in the following sections.

4.2.1 Main Steam System

The following subsections summarize the evaluation of the NSSS interface on the MSS major components relative to the SPU parameters. The major components of the MSS are the steam generator main steam safety valves (MSSVs), the steam generator power-operated atmospheric relief valves (ARVs), and the main steam isolation valves (MSIVs) and non-return valves.

4.2.1.1 Steam Generator MSSVs

The setpoints of the MSSVs are based on the design pressure of the steam generators (1085 psig) and the requirements of the *ASME Boiler and Pressure Vessel (B&PV) Code* (Reference 2). Since the design pressure of the steam generator has not changed for SPU, there is no need to revise the setpoints of the safety valves.

The MSSVs must have sufficient capacity so that main steam pressure does not exceed 110 percent of the steam generator shell-side design pressure (the maximum pressure allowed by the ASME B&PV Code) for the worst-case loss-of-heat-sink event (Reference 3). Based on this requirement, Westinghouse applies the conservative criterion that the valves should be sized to relieve 100 percent of the maximum calculated steam flow at an accumulation pressure not exceeding 110 percent of the MSS design pressure.

IP3 has 20 safety valves with a total rated capacity of 15.108 x 10^6 lb/hr, which provides about 107.8 percent of the maximum SPU full-load steam flow of the 14.01 x 10^6 lb/hr (see Table 2.1-2). Therefore, based on the range of NSSS design parameters for the SPU, the capacity of the installed MSSVs meets the Westinghouse sizing criterion.

The original design requirements for the MSSVs (as well as the ARVs and steam dump valves) included a maximum flow limit per valve of 890,000 lb/hr at 1085 psig. Since the actual capacity of any single MSSV, ARV, or steam dump valve is less than the maximum flow limit per valve, the maximum capacity criteria are satisfied.

The MSSVs are also discussed in Section 9.1 and the capability of the MSSVs is analyzed for the limiting design basis transient (loss-of-load event) in subsection 6.3.6 of this report. The analysis in subsection 6.3.6 demonstrates that the MSSVs are capable of maintaining the secondary side steam pressure below 110 percent of the steam generator shell design pressure.

4.2.1.2 Steam Generator Power-Operated ARVs

The ARVs, which are located upstream of the MSIVs and adjacent to the MSSVs, are automatically controlled by steam line pressure during plant operations. The ARVs automatically modulate open and exhaust to atmosphere whenever the steam line pressure exceeds a predetermined setpoint to minimize safety valve lifting during steam pressure transients. As the steam line pressure decreases, the ARVs modulate closed and reseat at a pressure below the opening pressure. The ARV set pressure for these operations is between zero-load steam pressure and the setpoint of the lowest set MSSVs. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ARV setpoint.

The primary function of the ARVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump to the condenser is not available. Under such circumstances, the ARVs, in conjunction with the AFWS, permit the plant to be cooled down from the pressure setpoint of the lowest-set MSSVs to the point at which the Residual Heat Removal System (RHRS) can be placed in service. During cooldown, the ARVs are either automatically or manually controlled. In automatic, each ARV proportional and integral (P&I) controller compares steamline pressure to the pressure setpoint, which is manually set by the plant operator.

To limit the frequency of main steam safety valve (MSSV) lifts, the setpoints of the ARVs are based on plant no-load conditions (2250 psig and 547°F) and the lowest MSSV setpoint. Since neither of these pressures changes for the proposed range of NSSS design parameters, there is no need to change the ARV setpoint.

In the event of a tube rupture event in conjunction with loss-of-offsite power (LOOP), the ARVs are used to cool down the RCS to a temperature that permits equalization of the primary and secondary pressures at a pressure below the lowest-set MSSV. RCS cooldown and depressurization are required to preclude steam generator overfill and to terminate activity release to the atmosphere (Reference 3 and Section 6.4).

The steam generator ARVs are sized to have a capacity equal to about 10 percent of rated steam flow at no-load pressure. This capacity permits a plant cooldown to RHRS operating conditions (350°F) in 4 hours (at a rate of about 50°F/hr), assuming cooldown starts 2 hours after reactor shutdown. This sizing is compatible with normal cooldown capability and minimizes the water supply required by the AFWS. This design basis is limiting with respect to sizing the ARVs, and bounds the capacity required for tube rupture.

An evaluation of the installed capacity (2,467,000 lb/hr at 1020 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of SPU NSSS design parameters.

4.2.1.3 MSIVs, MSIV Bypass Valves, and Non-Return Valves

The MSIVs and non-return valves are located outside the containment and downstream of the MSSVs and ARVs. The valves function to prevent the uncontrolled blowdown of more than one steam generator and to minimize the RCS cooldown and containment pressure to within acceptable limits following a main steamline break (MSLB). To accomplish this function, the design requirements specified that the MSIVs must be capable of closure within 5 seconds of receiving a closure signal against steam break flow conditions in the forward direction.

Rapid closure of the MSIVs and non-return valves following postulated steamline breaks causes a significant differential pressure across the valve seats and a thrust load on the MSS piping and piping supports in the area of the MSIVs and non-return valves. The worst cases for differential pressure increase and thrust loads are controlled by the steamline break area (affecting mass flow rate and moisture content), throat area of the steam generator flow restrictors, valve seat bore, and no-load operating pressure. Since the SPU does not affect these variables, the design loads and associated stresses resulting from rapid closure of the MSIVs and non-return valves will not change. Consequently, SPU does not affect the interface requirements for the MSIVs and non-return valves.

The MSIV bypass valves are used to warm up the main steamlines and equalize pressure across the MSIVs prior to opening the MSIVs. The MSIV bypass valves perform their function at no-load and low-power conditions at which the SPU has no significant effect on main steam conditions (for example, steam flow and steam pressure). Consequently, the SPU does not affect the interface requirements for the MSIV bypass valves.

4.2.2 Steam Dump System

The NSSS Reactor Control Systems and the associated equipment (pumps, valves, heaters, control rods, etc.) are designed to provide satisfactory operation (automatic in the range of 15- to 100-percent power) without reactor trip when subjected to the following load transients:

- Loading at 5 percent of full power per minute with automatic reactor control
- Unloading at 5 percent of full power per minute with automatic reactor control

- Instantaneous load transients of plus or minus 10 percent of full power (not exceeding full power) with automatic reactor control

- Load reductions of 50 percent of full power with automatic reactor control and steam dump

The Steam Dump System creates an artificial steam load by dumping steam from ahead of the turbine valves to the main condenser. The Westinghouse sizing criterion recommends that the Steam Dump System (valves and pipe) 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. To prevent a trip, this transient requires all NSSS Control Systems to be in automatic, including the Rod Control System, which accommodates 10 percent of the load reduction. A steam dump capacity of 40 percent of rated steam flow at full-load steam pressure also prevents MSSV lifting following a reactor trip from full power.

4.2.2.1 Steam Dump System Major Components

IP3 is equipped with 12 condenser steam dump valves and each valve is specified to have a flow capacity of 505,000 lbm/hr at a valve inlet pressure of 650 psia. The total capacity of the 12 valves provides a steam dump capacity of about 43.8 percent of current rated steam flow 13.26×10^6 lb/hr , or 5.808×10^6 lb/hr at a full load steam pressure of 762 psia (Reference 1).

The capacity of the Steam Dump System (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. NSSS operation within the proposed range of design parameters for power uprate will result in a reduced steam dump capability relative to the original Westinghouse sizing criteria. An evaluation indicates steam dump capacity could be as low as 29.4 percent of rated steam flow (13.93×10^6 lb/hr), or 4.10×10^6 lb/hr at a full-load steam pressure equal to 567 psia. At full-load steam pressures higher than 567 psia (T_{avg} = 549°F), steam dump capacity would increase. For example, at a full-load steam pressures of 743 psia (T_{avg} = 572°F), steam dump capacity would be 40.1 percent of rated flow (13.99×10^6 lb/hr), or 5.61×10^6 lb/hr.

The NSSS stability and operability analysis (Section 4.3 of this report) provides an evaluation of the adequacy of the Steam Dump System in conjunction with the control system setpoints at SPU conditions. Subsection 4.3.1 states that the 50-percent load rejection analysis assumes steam dump is available to the condenser, preventing both reactor trip and steam generator safety valve actuation. The analysis results indicated that for full-power T_{avg} values of 564°F and above, the 50-percent load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU, a 50-percent load rejection can

be accommodated. Based on these analyses, the condenser steam dumps meet requirements at SPU conditions as discussed above.

The condenser steam dump valves have NSSS requirements on time for opening and for modulating steam flow. To provide effective control of flow on large step-load reductions or plant trip, the steam dump valves are required to go from full-closed to full-open in 3 seconds at any pressure between 50 psi less than full-load pressure and steam generator design pressure. The dump valves are also required to modulate to control flow. For modulating steam dump flow, the positioning response may be slower with an allowed maximum full-stroke time of 20 seconds. These time response requirements are not affected by the SPU and must still be met.

4.2.3 Condensate and Feedwater System

The C&FS must automatically maintain steam generator water levels during steady-state and transient operations. The range of NSSS design parameters will affect both feedwater volumetric flow and system pressure drop. The volumetric flow may increase by as much as 6.1 percent, or decrease by as much as 3.7 percent and, therefore, system pressure drop may increase by as much as 11.9 percent, or decrease by as much as 4.6 percent during full-power operation. Comparison of the SPU design parameters with the 1.4-percent MUR design parameters indicated that steam generator full-power operating pressure may decrease by as much as 195 psi (762 to 567 psia).

The major components of the C&FS are the main feedwater regulator valves (FRVs), bypass feedwater regulator valves (BFRVs), and the C&FS pumps. Each of these major components is discussed in the sections that follow.

4.2.3.1 Main Feedwater Isolation/FRVs/BFRVs

The main FRVs and BFRVs are located outside containment. The valves function in conjunction with backup trip signals to the feedwater pump discharge isolation valves, feedwater pumps, and other miscellaneous valves to provide redundant isolation of feedwater flow to the steam generators following a steam line break or a malfunction in the steam generator level control system. Isolation of feedwater flow is required to prevent containment overpressurization and excessive RCS cooldowns. Redundant main feedwater isolation is provided by:

- Closure of all the main FRVs and closure of the low-flow feedwater bypass valves, or

- Closure of the main feedwater pump discharge valves that initiate closure of the MFIVs and a trip of the main feedwater pumps.

The quick-closure requirements imposed on the FRVs, BFRVs, and the backup feedwater pump discharge isolation valves causes dynamic pressure changes that may be of large magnitude and must be considered in the design of the valves and associated piping. The worst loads occur following a steam line break from no-load conditions with the conservative assumption that all feedwater pumps are in service providing maximum flow following the break. Since these conservative assumptions are not affected by the SPU, the current design loads and associated stresses resulting from rapid closure of these valves will not change. As noted in Tables 2.1-1 and 2.1-2 in this document, no-load temperature is 547°F. Saturation pressure is 1020 psia at 547°F. This provides the initiating conditions for which the valves would be required to function. The feedwater pumps would provide flow to the steam generators at a pressure sufficient to feed the steam generators with a steam generator pressure of 1020 psia. Since the SPU does not change the no load temperature, the previous analysis remains valid.

4.2.3.2 FRVs, C&FS Pumps

The C&FS available head in conjunction with the FRV characteristics must provide sufficient margin for feed control to ensure adequate flow to the steam generators during steady-state and transient operation. A continuous steady feed flow should be maintained at all secondary system loads. To ensure stable feedwater control with variable speed feedwater pumps, the pressure drop across the FRVs at rated flow (100-percent power) should be approximately equal to the dynamic losses from the feed pump discharge to the steam generator. These dynamic losses include the frictional resistance of feed piping, high-pressure feedwater heaters, feed flow meter, and steam generator. To preclude reactor trip following load rejection, adequate margin should be available in the FRVs at full-load conditions to permit C&FS delivery of 96 percent of rated flow with a 100-psi pressure increase above the full-load pressure with the FRVs fully open. The current Feedwater Pump Speed Control Program results in FRV lift of about 80 percent at T_{avg} of 567°F. A FRV lift of about 80 percent is considered optimum at full load with respect to both valve duty and feedwater control during steady-state and transient operation.

The hydraulic evaluation of the C&FS for the range of design parameters approved for the SPU indicates the lift of the FRVs at full power will increase by as much as 11.3 percent (from 80 to 91.3 percent at T_{avg} of 572°F) with the present Feedwater Pump Speed Control Program. See Section 9.4 of this document for a discussion of the hydraulic evaluation of the C&FS for a large load rejection.

To provide effective control of flow during normal operation, the FRVs are required to stroke open or closed in 20 seconds over the anticipated inlet pressure control range (approximately 0 to 1600 psig). Additionally, rapid closure of the FRVs is required after receiving a trip close

signal in order to mitigate certain transients and accidents. These requirements are not affected by the SPU.

4.2.4 Auxiliary Feedwater System

The AFWS supplies feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the steam generator heat sink. The system provides feedwater to the steam generators during normal unit startup, hot standby, and cooldown operations and also functions as an engineered safety feature (ESF). In the latter function, the AFWS is required to prevent core damage and system overpressurization during transients and accidents, such as a loss-of-normal feedwater or a secondary system pipe break. The minimum flow requirements of the AFWS are dictated by accident analyses, and since the SPU affects these analyses, evaluations of the limiting transients and accidents are performed to confirm that the AFWS performance is acceptable at the SPU conditions. These evaluations are described in Section 6 of this report and show acceptable results. Additional discussion of the AFWS is provided in Section 9.12 of this report. The acceptance criteria for the AFWS are discussed in subsection 9.12.4.

4.2.4.1 AFW Storage Requirements

The AFWS pumps are normally aligned to take suction from the condensate storage tank (CST). To fulfill the ESF design functions, sufficient feedwater must be available during transient or accident conditions to enable the plant to be placed in a safe shutdown condition.

The limiting transient with respect to CST inventory requirements is the LOOP transient. The IP3 licensing basis requires that, in the event of a LOOP, sufficient CST useable inventory must be available to bring the unit from full-power to hot-standby conditions, and maintain the plant at hot standby for 24 hours.

Since the required CST inventory is a function of plant-rated power and other NSSS design parameters, a new analysis was performed to determine the required inventory for the range of NSSS design parameters approved for SPU. This analysis is based on the following conservative assumptions:

- Reactor trip occurs from 102 percent of rated core power (3216 MWt), from a low-low water level in the steam generators. A 2-second delay is assumed before reactor trip following LOOP.
- Steam is released from the steam generators at the first safety valve setpoint plus setting tolerance for drift.

- The steam generators are filled back up to 52-percent narrow range water level.
- The CST operating fluid temperature is at the maximum allowable value (120°F).

The analysis concluded that a minimum required useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for SPU. As discussed in Section 9.12, the CST *Technical Specification* requirement of 360,000 gallons ensures a usable volume of 288,500 gallons to meet the limiting design basis requirement.

4.2.5 Steam Generator Blowdown System

The Steam Generator Blowdown System (SGBS) is used to control the chemical composition of the steam generator secondary side water within the specified limits. The SGBS also controls the buildup of solids in the steam generator secondary side.

The blowdown flow rates required during plant operation are based on chemistry control and tube-sheet sweep requirements to control the buildup of solids. The blowdown flow rate required to control chemistry and the buildup of solids in the steam generators is based on allowable condenser in-leakage, total dissolved solids in the plant circulating water, and the allowable primary to secondary leakage. Since these variables are not affected by the SPU, the blowdown required to control secondary chemistry and steam generator solids will not be affected by the SPU.

The inlet pressure to the SGBS varies with steam generator operating pressure. Therefore, as steam generator full-load operating pressure decreases, the inlet pressure to the SGBS control valves decreases and the valves must open to maintain the required blowdown flow rate into the system flash tank. The 1.4-percent MUR NSSS design parameters (Table 2.1-1) evaluate a maximum decrease in steam pressure from no-load to full-load of 258 psi (that is, from 1020 to 762 psia). Based on the revised range of SPU NSSS design parameters, the no-load steam pressure (1020 psia) remains the same, and the minimum full-load steam pressure (567 psia) decreases about 26 percent. As noted in the footnote to Table 2.1-2, steam pressure will be limited to 650 psia during actual operation. This decrease in blowdown system inlet pressure is evaluated in Section 9.5 of this report.

4.2.6 Conclusions

The following is a brief summary of the NSSS/BOP interface evaluation conclusions for the IP3 SPU.

Main Steam System

The capacity of the installed MSSVs meets the original sizing bases for the approved range of NSSS design parameters. The MSSVs are also discussed in Section 9.1 of this report and the capability of the MSSVs is analyzed for the limiting design basis transient (loss-of-load event) in subsection 6.3.6 of this report. The analysis in subsection 6.3.6 demonstrates that the MSSVs are capable of maintaining the secondary side steam pressure below 110 percent of the steam generator shell design pressure.

An evaluation of the installed capacity of the PORVs (2,467,000 lb/hr at 1020 psia) indicates that the original design bases in terms of plant cooldown capability can still be achieved for the range of SPU NSSS design parameters.

The SPU does not affect the design interface requirements for the MSIVs, MSIV bypass valves, and non-return valves.

Steam Dump System

An evaluation of the Steam Dump System indicates that the minimum system capacity is approximately 29 percent of the SPU full-load steam flow at the minimum allowable full-load steam pressure of 567 psia. At full-load steam pressures higher than 567 psia, steam dump capacity would increase. The NSSS stability and operability analysis provides an evaluation of the adequacy of steam dump in conjunction with the control system setpoints (see Section 4.3 of this report). Subsection 4.3.1 states that the 50-percent load rejection analysis assumes steam dump is available to the condenser, preventing both reactor trip and steam generator safety valve actuation. The analysis results indicated that for full-power T_{avg} values of 564°F and above, the 50-percent load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU, a 50-percent load rejection can be accommodated. Based on these analyses, the condenser steam dumps meet requirements at SPU conditions as discussed above.

Condensate and Feedwater System

The hydraulic evaluation of the C&FS for the range of design parameters approved for the SPU indicates the lift of the FRVs at full power will increase by as much as 11.3 percent (from 80 to 91.3 percent at T_{avg} of 572°F) with the present Feedwater Pump Speed Control Program. See Section 9.4 of this document for a discussion of the hydraulic evaluation of the C&FS for a large load rejection.

Auxiliary Feedwater System

The AFWS is capable of delivering the minimum flow requirements for the SPU (see Section 6 of this report).

The CST minimum useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for SPU. The current *Technical Specification* value of 360,000 gallons ensures a usable volume of 288,500 gallons.

Steam Generator Blowdown System

The blowdown flow required to control secondary chemistry and steam generator solids is not affected by the SPU.

4.2.7 References

1. *Indian Point Nuclear Generating Unit No.3 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, Entergy Nuclear Operations, Inc., May 2002.

2. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition with Winter 1965 Addenda, The American Society of Mechanical Engineers, New York, NY.

3. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4.3 Nuclear Steam Supply System Control Systems

4.3.1 NSSS Stability and Operability

4.3.1.1 Introduction

Control systems operability analyses were performed on the Nuclear Steam Supply System (NSSS) control system setpoints for the Indian Point Unit 3 (IP3) plant to determine that there is adequate margin to relevant reactor trip and engineered safety features (ESFs) actuation setpoints for the proposed stretch power uprate (SPU). The conditions that were used as starting points for these analyses are provided in Section 2 of this report (NSSS parameters) and encompass a range of plant operating conditions.

The following cases, at both high- and low-T_{avg} conditions, were analyzed:

- Fifty-percent load rejection from 100-percent power
- Ten-percent step-load decrease from 100-percent power
- Ten-percent step-load increase from 90-percent power
- Turbine trip without reactor trip

4.3.1.2 Input Parameters and Assumptions

The conditions that were used as starting points for these analyses are provided in Section 2 of this report and encompass a range of plant operating conditions. However, the steam pressure for the low T_{avg} conditions shown in Section 2 was not able to be supported by the NSSS design transient analyses described in Section 3.1 of this report. The minimum full-power steam pressure that could be supported was a value of 650 psia (due to steam generator tubesheet ΔP considerations). This resulted in the following full-power T_{avg} values for this minimum acceptable full-power steam pressure:

Zero-percent steam generator tube plugging (SGTP):	Full-power T_{avg} = 550.6°F
Ten-percent SGTP:	Full-power T_{avg} = 563.7°F

The stability and operability analyses bracketed all operating conditions: full-power T_{avg} ranging from the above minimum values for a minimum full-power steam pressure of 650 psia to an upper limit of 572.0°F, and 0- to 10-percent SGTP levels. The following assumptions were made for all normal transients analyzed:

- All applicable NSSS control systems were assumed to be operational and in the automatic mode of control (that is, rod control, steam dump control, pressurizer level, steam generator level control, and pressurizer pressure control).

- Two-percent initial power level uncertainty was assumed. The remainder of the plant parameters (that is, Reactor Coolant System [RCS] T_{avg}, pressurizer pressure, pressurizer level, steam generator level) were assumed to be at their nominal control system setpoints.

- Best-estimate reactor kinetics parameters were modeled (that is, rod worth, moderator temperature coefficient [MTC], Doppler power defect, etc.) Since beginning-of-life (BOL) core physics parameters have lower differential rod worth and a less negative MTC, modeling BOL core characteristics typically yielded more conservative results that bound the full cycle of operation.

- In general, analysis of 10-percent SGTP conditions bounds the 0-percent tube plugging conditions. Higher SGTP was somewhat more conservative for short-term heatup transients due to a slower rate of heat transfer from the primary to secondary side of the plant. Furthermore, lower nominal steam temperatures and pressures reduced steam dump capacity during heatup transients, and reduced margin to safety injection (SI) actuation on low steam pressure during cooldown transients.

- The transient simulations were modeled to run for a 500-second interval (about 8 minutes). Most challenges to the reactor trip and ESF actuation setpoints occurred within the first minute of the design basis normal condition transients, therefore this simulation time frame was considered more than adequate for assessing control system response and stability considerations.

- The following protection systems functions have the greatest potential for being challenged during these operability transients and therefore were considered in this analysis (other protection systems would only be challenged during these transients if one of the following did not function).

Overtemperature ΔT

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

Parameter	Setpoint
K_1	1.22
K_2	0.022/°F
K_3	0.0007/psi
τ_1	25 sec
τ_2	3 sec
τ_4	0 sec (not shown in Technical Specifications since value is 0.0)
τ_5	0 sec (not shown in Technical Specifications since value is 0.0)
ΔT_0	Indicated ΔT at rated thermal power (RTP), °F
T	Measured RCS T_{avg}, °F
T'	Reference T_{avg} at RTP, °F
P	Measured pressurizer pressure, psig
P'	Nominal RCS operating pressure, psig
ΔT	Measured ΔT, °F
$f_1(\Delta I)$	= [*] {[*] - (q_t - q_b)} when (q_t - q_b) < [*] RTP = 0.0 of RTP when [*] RTP < (q_t - q_b) < [*] RTP = [*] {(q_t - q_b) - [*]} when q_t - q_b > [*] RTP Where q_t and q_b are fraction RTP in the upper and lower halves of the core, respectively, and q_t + q_b is the total THERMAL POWER in fraction RTP.

*These values denoted with [*] are specified in the *Core Operating Limit Report* (COLR).

Overpower ΔT

$$\Delta T\left(\frac{1}{1+\tau_4 s}\right)\leq \Delta T_0\{K_4-K_5\left(\frac{1}{(1+\tau_5 s)}\frac{\tau_3 sT}{(1+\tau_3 s)}\right)-K_6[T-T']\}$$

Parameter	Setpoint
K_4	1.074
K_5	0.0175/°F
K_6	0.0015/°F
τ_3	10 sec
τ_4	0 sec (not shown in Technical Specifications since value is 0.0)
τ_5	0 sec (not shown in Technical Specifications since value is 0.0)

ΔT_0	Indicated ΔT at RTP, °F
T'	Reference T_{avg} at RTP, °F
ΔT	Measured ΔT, °F

High-pressurizer pressure reactor trip:	2365 psig
Low-pressurizer pressure reactor trip:	1930 psig
Lead time constant:	9 seconds
Lag time constant:	1 second
Low-pressurizer pressure SI:	1780 psig
High steamline flow SI	54-percent flow from 0 – 20 percent load, linearly increasing to 120-percent flow at 100-percent load
Low steamline pressure:	616 psig
Low T_{avg}:	542°F

These assumptions were used as inputs for the analyses in the following subsections. These subsections describe in greater detail each of the transients analyzed.

4.3.1.3 Fifty-Percent Load Rejection from Full-Power Transient

4.3.1.3.1 Description of Analysis and Evaluations

A 50-percent load rejection with steam dump transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 50-percent load rejection transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 50-percent load rejection is the most severe operational transient that the plant would normally undergo without a reactor trip. The transient was modeled as a turbine runback from 100- to 50-percent power, at a maximum rate of 200-percent per minute. The 200-percent-per-minute transient is the fastest unloading rate that the turbine can normally perform, so this was used in the analyses.

The RCS average temperature, RCS and pressurizer pressure, and secondary side steam pressure increased rapidly following this transient initiation. The steam dump was available to the condenser, preventing both reactor trip and steam generator safety valve actuation. All NSSS control systems were available to mitigate this transient.

4.3.1.3.2 Acceptance Criteria

The 50-percent load rejection from full power should provide adequate margins to the nominal trip setpoints (see subsection 4.3.1.2). The plant response should be stable and non-oscillatory. There should be adequate pressurizer PORV capacity to prevent the transient from reaching the high-pressurizer pressure reactor trip setpoint.

4.3.1.3.3 Results

The initial analyses were performed for the low T_{avg} range of operation as noted in subsection 4.3.1.2. While the results showed margin was needed for the overtemperature ΔT (OTΔT) trip setpoint (limiting protection system function), at the lower limiting T_{avg} of 550.6°F, as the full-power T_{avg} is increased to the range expected for future SPU operations, larger load rejections can be successfully handled without resulting in a reactor trip. The analyses results indicated that, for full-power T_{avg} values of 564°F and above, the 50-percent design basis load rejection could be accommodated. Therefore, for the full-power T_{avg} value of 567°F at which the plant will operate with the SPU implementation, a 50-percent load rejection can be accommodated.

As the full-power T_{avg} value is increased, the load rejection transient becomes less limiting. This is due to a combination of reasons:

- Higher values of T_{avg} result in more of an initial temperature error to the steam dump control logic, thereby increasing the initial steam dump opening.

- Higher values of T_{avg} result in higher steam pressures, thereby increasing the steam dump flow for a given steam dump valve position.

- Higher values of T_{avg} result in a more negative value of the fuel MTC, thereby producing greater fuel reactivity effects to mitigate the transient.

The control system response was smooth during the transient with no oscillatory response noted. All parameters responded smoothly with no sustained or divergent oscillations.

The peak-pressurizer pressure was controlled by the pressurizer power-operated relief valve (PORV) actuation, thereby preventing the pressurizer pressure from reaching the high-pressurizer pressure reactor trip setpoint and showing acceptable capacity for the pressurizer PORVs. The peak steam pressure was no higher than the no-load steam pressure, so the steam generator atmospheric relief valves (ARVs) were not challenged.

In summary, the 50-percent load rejection transient can be successfully accommodated when the T_{avg} is 564°F or higher.

4.3.1.4 Ten-Percent Step-Load Decrease from Full-Power Transient

4.3.1.4.1 Description of Analysis and Evaluations

A 10-percent step-load decrease from full-power transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 10-percent step-load decrease transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 10-percent step-load decrease was initiated from 100-percent power. Secondary side steam pressure and temperature initially increased, lagged by an increase in the primary side average temperature (T_{avg}) and RCS pressure. The power mismatch between the turbine load and nuclear power, and the resultant temperature error between the T_{avg} and reference temperature (T_{ref}) caused the rods to move into the core, reducing core power. Reactor coolant temperature and pressure were then restored to their equilibrium values.

This transient should not result in the pressurizer pressure reaching the pressurizer PORV actuation setpoint. Stability of the Rod Control System was also assessed.

4.3.1.4.2 Acceptance Criteria

During the 10-percent step-load decrease transient, the PORV actuation setpoint should not be challenged. Therefore, the maximum pressure reached during this transient should be below the PORV actuation setpoint of 2350 psia (2335 psig).

4.3.1.4.3 Results

This transient is the same one that was used to verify acceptability of the pressurizer spray capacity in subsection 4.3.2 in this report. The analyses performed for the spray capacity included additional conservatisms not normally used in the plant operability analyses (that is, T_{avg} uncertainty of 7.5°F), and therefore bracketed the best-estimate analyses normally used in the plant operability analyses. The results indicated that no reactor trip setpoints were challenged and the control system response was stable and non-oscillatory. Pressurizer pressure reached a maximum of 2332 psia (2317 psig) for the high T_{avg} case and the PORVs were not challenged. Therefore, the plant response for the 10-percent step-load decrease transient is acceptable for the SPU.

4.3.1.5 Ten-Percent Step-Load Increase from 90-Percent Power Transient

4.3.1.5.1 Description of Analysis and Evaluations

A 10-percent step-load increase from 90-percent power transient was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the 10-percent step-load increase transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The 10-percent step-load increase was initiated from 90-percent power. Secondary steam pressure and temperature decreased initially, followed by a decrease in the primary side T_{avg} and pressurizer pressure. Pressurizer heaters are actuated to restore system pressure. The power mismatch between the turbine load and nuclear power, and the resultant temperature error between T_{avg} and T_{ref} would cause the rods to move out of the core, increasing core power until the final 100-percent power condition is reached.

Since the 10-percent step-load increase transient will result in the lowest steam pressure of any of the operational transients, it is analyzed in order to demonstrate that ESF actuation will not occur on low steam pressure.

4.3.1.5.2 Acceptance Criteria

The 10-percent step-load increase was analyzed to demonstrate that ESF actuation would not occur due to the plant cooldown. The critical function is the ESF actuation on high steamline flow coincident with low steamline pressure (616 psig or 631 psia) or low T_{avg} (542°F). While the transient will not actuate the high steamline flow trip setpoint at 100-percent power, partial actuation of the other functions could occur. Analyses were performed at the lower range of T_{avg} since this operating condition has the lowest margin to the low steamline pressure or low T_{avg} setpoints. The limiting case is for the minimum full-power steam pressure of 650 psia, the 0-percent SGTP conditions that resulted in a minimum full-power T_{avg} of 550.6°F.

4.3.1.5.3 Results

The results for the limiting case, in which the full-power T_{avg} is 550.6°F with a minimum full-power steam pressure of 650 psia and 0-percent SGTP conditions, indicated that the plant would experience a plant cooldown. The minimum T_{avg} was 545°F, which is just above the low T_{avg} setpoint of 542°F portion of the high-steamline flow ESF function. The minimum steam pressure was 612 psia, below the low-steam pressure setpoint of 631 psia portion of the high steamline flow ESF function. The RCS cooldown was enough to potentially result in shutoff of

the pressurizer heaters since the level dropped to 18.3-percent, just above the low-level heater cutoff setpoint of 18-percent of span. The 10-percent step-load increase transient was also performed at a full-power T_{avg} of 567°F, which resulted in a RCS cooldown but there was greater margin to the various functions except the low-steamline pressure portion of the high steamline flow ESF function. For this case, the minimum steam pressure reached was 628 psia, which is just below the low-steamline pressure setpoint of 631 psia; however, the Engineered Safety Feature Actuation System (ESFAS) actuations are partial actuations that require a high-steamline flow measurement, which will not be reached during this transient. Also, for this case, the pressurizer level drops due to the cooldown but remains above the low-level heater cutoff setpoint of 18-percent of span.

4.3.1.6 Turbine Trip without Reactor Trip from P-8 Setpoint or Below

4.3.1.6.1 Description of Analysis and Evaluations

A turbine trip without reactor trip transient from the P-8 setpoint or below was analyzed using the IP3 model of the LOFTRAN code (Reference 1). Since the turbine trip transient is loop-symmetric, a single-loop version of the LOFTRAN code was used. This computer code is a system-level program code and models the overall NSSS, including the detailed modeling of the control and protection systems.

The turbine and reactor trip logic was coupled with the P-8 permissive. If a turbine trip occurs from a power level above the P-8 permissive, the turbine trip would actuate a reactor trip. If a turbine trip occurs from a power level at or below the P-8 permissive, no immediate reactor trip would occur. The nominal analysis value for the P-8 setpoint was 35-percent power, but analyses were also performed below the P-8 setpoint, at 20-percent power. Therefore, a turbine trip without reactor trip transient (that is, turbine trip from power level at or below the P-8 setpoint) can be considered as being a load rejection, and the 50-percent load rejection analyses described in subsection 4.3.1.3 of this report would cover this transient. However, another acceptability requirement of this transient is that the pressurizer PORVs are not actuated. This requirement is the limiting requirement for transient acceptability.

4.3.1.6.2 Acceptance Criteria

The turbine trip without reactor trip transient from the P-8 setpoint or lower power level should provide adequate margins to the nominal trip setpoints (see subsection 4.3.1.2). The plant response should be stable and non-oscillatory. The pressurizer PORVs should not be actuated during this transient. While not a requirement, it is desirable that the steam generator ARVs are not challenged during this transient.

4.3.1.6.3 Results

The following assumptions were made besides those described in subsection 4.3.1.2.

- The Rod Control System was assumed to be in manual; no credit was taken for rod motion.

- The analyses were performed for both the 0-percent SGTP (full-power T_{avg} = 550.6°F) and 10-percent SGTP (full-power T_{avg} = 563.7°F) cases for the minimum acceptable full-power steam pressure of 650 psia. Normally, the higher SGTP case is limiting, but the lower SGTP case would have the lower (T_{avg} - $T_{no\ load}$) signal to the steam dump valves and, therefore, the greater amount of plant heatup (and resulting higher pressurizer insurge and peak pressurizer pressure). Analyses for these low extremes of full-power T_{avg} would bound the results for higher values of T_{avg}.

The turbine trip without reactor trip analyses from 35-percent power (that is, the P-8 setpoint) showed unacceptable results (that is, there was not adequate margin to the PORV actuation setpoint) for the 0-percent STGP case; however, the analyses from 20-percent power showed acceptable results. For the 10-percent SGTP case, the turbine trip without reactor trip analyses showed acceptable results from both 35-percent power and 20-percent power, where the peak-pressurizer pressures were 2317 and 2304 psia, respectively.

The above analyses were performed at the lower limiting T_{avg} values for plant operation at the minimum acceptable full-power steam pressure of 650 psia. As the full-power T_{avg} (and consequentially the full-power steam pressure) was raised above this lower limit, the peak-pressurizer pressure was reduced. Therefore, a turbine trip without reactor trip transient is acceptable with the P-8 setpoint set to 20-percent power for T_{avg} values of 550.6°F and above, or with the P-8 setpoint set to 35-percent power for T_{avg} values of 564°F and above. A P-8 setpoint of 35-percent power is acceptable for the full-power T_{avg} value of 567°F, at which the plant will operate for the SPU implementation.

4.3.1.7 Conclusions of the Control Systems Operability Analyses

The control systems operability analyses were performed for the entire full-power T_{avg} window (see subsection 4.3.1.2); however, the plant will operate at a full power T_{avg} of 567°F following the SPU implementation. The following was concluded from the plant operability analyses performed for this expected 567°F operating point:

The 10-percent step-load decrease transient can be accommodated successfully without challenging the pressurizer PORVs for the full-power T_{avg} window.

The 10-percent step-load increase transient can be accommodated successfully without challenging any reactor trip setpoints for full-power T_{avg} values of 564°F and above. The low-steamline pressure portion of the high steamline flow ESF actuation could be actuated while performing this transient with a full-power T_{avg} of 564°F or higher; however, the ESFs actuations are partial actuations that require a high steamline flow coincident measurement, which will not be reached during this transient.

The 50-percent load rejection can be successfully accommodated for full-power T_{avg} values of 564°F and above.

The turbine-trip-without-reactor trip from a power level corresponding to the P-8 setpoint or lower can be successfully accommodated with the P-8 setpoint set to 35-percent power for full-power T_{avg} values of 564°F and above.

The control systems are stable and support the SPU for all normal condition transients; no long-term, continuous, or diverging plant parameter oscillations were noted during any of the operational transients.

4.3.2 Pressurizer Pressure Control System Component Sizing

The various NSSS pressure control components are intended to maintain the pressurizer pressure at the nominal setpoint during steady-state operation, and to control the pressure excursions that occur during design basis transients to an extent that a reactor trip, ESFAS actuation, or a pressurizer safety valve actuation would not occur. This assessment shows that the installed capacity of the various pressure control components remains acceptable for the SPU conditions.

The following pressure control components were evaluated:

- Pressurizer heaters
- Pressurizer spray valves
- Pressurizer PORVs

4.3.2.1 Pressurizer Heaters

The pressurizer heaters are sized to be able to heat up the pressurizer liquid at a 200°F/hr rate during the initial plant heatup phase from cold shutdown. In addition, they are intended to assist the plant in controlling the pressurizer pressure decrease that would occur during design basis transients that result in pressurizer outsurge events. These include the initial part of a 10-percent step-load increase transient, a 5-percent-per-minute-plant-unloading transient, or

events resulting in a reactor trip. The design basis pressurizer heater capacity is 1 kW of heater capacity per cubic foot of pressurizer free volume. Generic analyses on Westinghouse plants have shown that the pressurizer heater capacity is not a strong influence on the minimum pressure noted during the above operational events or during reactor trips. The minimum pressure is controlled by the outsurge that results during the transient. Analyses have been performed in which the pressurizer heater capacity has been reduced by as much as 20 percent, and no major difference has been observed in the analysis results. The heatup time from cold shutdown to hot standby was not affected by the SPU. The heatup maneuver would be essentially the same as that which IP3 presently experiences. Therefore, the installed pressurizer heater capacity meets the acceptance criterion at the SPU conditions.

4.3.2.2 Pressurizer Spray

The design basis for the pressurizer spray capacity is that it is able to handle a 10-percent step-load decrease transient without resulting in the pressure increasing to the pressurizer PORV setpoint. The limiting case is a 10-percent step-load decrease from 100- to 90-percent power.

The SPU power rating would tend to increase the demand on the pressurizer spray. Therefore, the pressurizer spray sizing was analyzed to ensure acceptability. The analysis included the following assumptions:

- The plant is initially at 102 percent (100-percent nominal power with 2-percent uncertainty) of the 3230-MWt SPU NSSS power level.
- The plant is initially at nominal T_{avg} + 7.5°F uncertainty.
- The transient is a step-load reduction from the noted 102-percent turbine load to 90-percent load.
- Initial pressurizer pressure is at nominal pressure of 2250 psia.
- The initial pressurizer water level is at nominal values.
- The steam generator heat transfer coefficient increases to the maximum credible value (0-percent fouling, 0-percent SGTP).
- Best-estimate nuclear design parameters (moderator temperature coefficient, Doppler power defect, control rod worth, and startup data) are at conservative BOL conditions.

- Credit is taken for automatic operation of all normally functioning NSSS control systems (reactor control, pressurizer pressure and level control, and feedwater control; steam dump is not credited for a 10-percent step-load transient).

- The installed spray capacity analyzed is 325 gpm/valve for a total of 650 gpm.

The limiting case is for the plant operating at the upper limit T_{avg} of 572°F. For this case, the peak pressurizer pressure was 2332 psia, which is below the pressurizer PORV setpoint of 2350 psia. Therefore, the installed pressurizer spray capacity meets the acceptance criterion at the SPU conditions.

4.3.2.3 Pressurizer PORVs

The design basis for the pressurizer PORV capacity is to be able to handle a 50-percent load decrease transient without resulting in the pressure increasing to the high-pressurizer pressure reactor trip setpoint. The limiting case is a 50-percent load decrease from 100- to 50-percent power at 200 percent per minute.

The pressurizer PORV sizing analysis was performed at the IP3 SPU operating conditions defined in Section 2.1. The analysis was intended to bracket the window of operating conditions, a full-power T_{avg} of 549° to 572°F, and 0- to 10-percent SGTP levels. However, at the lower end of the T_{avg} window (that is, 549°F), the corresponding full-power steam pressure of 591 psia (Table 2.1-2) would violate the minimum acceptable full-power steam pressure of 650 psia that is required to avoid violating the primary-to-secondary pressure differential of 1700 psid. Thus, this PORV sizing analysis brackets the following window of operating conditions, with full-power T_{avg} ranging from 550.6° to 572°F, and 0- to 10-percent SGTP levels.

With the SPU NSSS power of 3230-MWt, the demand on the pressurizer PORVs would tend to increase. Therefore, the pressurizer PORV sizing was analyzed to ensure acceptability. The analysis included the following assumptions:

- The plant is initially at 102 percent (100-percent nominal power with 2-percent uncertainty) of the 3216-MWt SPU power level.

- The plant is initially at nominal T_{avg} + 7.5°F uncertainty.

- The transient is a load decrease from the noted 102-percent turbine load to 50-percent load at 200-percent per minute.

- The initial pressurizer pressure is at nominal pressure of 2250 psia.

- The initial pressurizer water level is at nominal values.

- The steam generator heat transfer coefficient increases to the maximum credible value (0-percent fouling, 0-percent SGTP).

- The fuel reactivities are at conservative BOL conditions.

- Credit is taken for automatic operation of all NSSS control systems (reactor control, pressurizer pressure and level control, feedwater control, and steam dump control).

- The installed PORV capacity analyzed is 179,000 lb/hr per PORV.

The limiting case for this sizing analysis occurs for the plant operating at the upper limit T_{avg} of 572°F. For this case, the pressurizer PORVs had sufficient capacity to avoid the pressurizer pressure from rising to the implemented high-pressurizer pressure reactor trip setpoint of 2377 psia.

The 50-percent step-load decrease was modeled as a 50-percent load rejection at a maximum turbine-unloading rate of 200-percent/minute. With this modeling, the pressurizer PORV capacity was sufficient to avoid a reactor trip on high-pressurizer pressure.

4.3.2.4 Conclusions

Based on this review, the existing pressurizer pressure control component sizing (pressurizer heaters, spray, and PORVs) meets the acceptance criterion at the SPU conditions.

4.3.3 Overpressure Protection System

As a result of the IP3 SPU, the plant operating parameters have changed from the present licensed parameters. The affected parameters are shown in Table 2.1-2. These are at-power parameters. However, the Overpressure Protection System (OPS) only comes into operation during zero-power operation during plant heatup, cooldown, or any operation between cold shutdown and hot standby.

The OPS setpoints would only be required to be evaluated and potentially revised for reasons such as:

- Changes in the design basis transients for which the OPS provides protection (that is, changes in the design basis mass input or heat input transients). There are no changes in the design basis transients.

- Appendix G pressure-temperature (P-T) limit changes in the adverse direction. Note that a change in the effective full-power years (EFPYs) applicable to the P-T limits does not constitute a reason to revise the setpoints; only an adverse change in the P-T limits themselves would warrant a setpoint re-analysis. There are no changes in the P-T limits.

- Some physical component in the plant changes that affects the performance of the OPS (for example, steam generator replacement, different pressurizer PORV stroke time or flow characteristic, different charging, or SI pump with a revised head/flow curve). The one analysis difference is in the design value of the SGTP level, which is being revised to 10 percent for the SPU (see Table 2.1-2 of this report) versus the present 25-percent tube plugging level (see Table 2.1-1 in Section 2 of this report). Therefore, the existing analyses for the 0- to 25-percent tube plugging level bracket the SPU 0- to 10-percent plugging level.

Based on this review, the installed OPS setpoints are not affected by the SPU.

4.3.4 IP3 SPU Instrumentation and Control Systems

4.3.4.1 Introduction

The Reactor Trip System (RTS), Engineered Safety Feature Actuation System (ESFAS), and NSSS Auxiliary System instrumentation have been reviewed to identify changes to setpoints, time constants, logic matrices, electrical power requirements, hardware, separation requirements, and cable routing.

4.3.4.2 I&C Instrumentation Hardware Change

The RTS and ESFAS were reviewed for hardware and other changes.

The following NSSS Auxiliary Systems were reviewed for hardware and other changes:

- Reactor Coolant System (RCS)
- Chemical and Volume Control System (CVCS)
- Residual Heat Removal System (RHRS)
- Safety Injection System (SIS)
- Containment Spray System (CSS)
- Component Cooling Water System (CCWS)
- Service Water System (SWS)

- Spent Fuel Pit Cooling System (SFPCS)
- Primary Sampling System (PSS)
- Emergency Diesel Generator (EDG) Loading System

4.3.4.3 Equipment Environmental Qualification

Environmental qualification (EQ) (temperature, pressure, and humidity) of hardware to be replaced due to the SPU was addressed.

4.3.4.4 Equipment Seismic Qualification

There is no credible reason that the SPU would adversely affect the seismic qualification of existing safety-related equipment. Therefore, the seismic qualification documentation for the existing safety-related equipment is not changed due to the SPU.

4.3.4.5 Instrumentation Settings and Setpoint Changes

The following settings, setpoints, hardware, and other changes are due to the SPU

- "K constants" (values for the overtemperature ΔT/overpower ΔT [OTΔT/OPΔT] setpoint equations)

- Steam flow transmitters

- Steam flow channel

- Turbine pressure

- Turbine pressure transmitters

- Low-pressurizer pressure trip lead/lag values

The safety functions associated with the above changes are not adversely affected.

4.3.4.6 Conclusions

The SPU will require changes to some NSSS instruments and control systems setpoints, time constants, and hardware. However, logic matrices, separation requirements, cable routing, electrical power requirements, and the system safety functions are not required to be changed as a result of the SPU. The setpoint/scaling and time constant changes associated with the SPU are within the capability of the instrumentation. Implementation of the identified changes

(hardware, setpoints, re-span, re-calibrate, etc.) configures the instruments and control systems to support the SPU operation. The instrument and control system instrumentation changes have been shown to be acceptable for the SPU.

4.3.5 References

1. WCAP-7878, *LOFTRAN Code Description*, Rev. 6, G. E. Heberle, February 2003.

5.0 NUCLEAR STEAM SUPPLY SYSTEM COMPONENTS

Evaluations were performed to determine the effects of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) parameters on the Nuclear Steam Supply System (NSSS) components. In general, the SPU-related inputs used for these evaluations are the Performance Capability Working Group (PCWG) parameters (refer to Section 2) and the NSSS design transient changes (found in Section 3.1). Additional input parameters specific to particular components (for example, NSSS auxiliary equipment design transients for the auxiliary equipment evaluations) were considered and are discussed in the appropriate component evaluation section. The purpose of the evaluations performed for the NSSS components was to confirm that they continue to satisfy the applicable codes, standards, and regulatory guides under the SPU conditions.

Evaluations were performed in the following areas, and are described within the remainder of this section:

- Reactor vessel structural integrity
- Reactor pressure vessel (RPV) system
- Control rod drive mechanisms (CRDMs)
- Reactor coolant loop (RCL) piping and supports
- Reactor coolant pumps (RCPs) and motors
- Steam generators
- Pressurizer
- NSSS auxiliary equipment
- Fracture integrity of NSSS components
- Additional materials considerations for the Reactor Coolant System (RCS)

5.1 Reactor Vessel

5.1.1 Reactor Vessel Structural Integrity

5.1.1.1 Introduction

Evaluations were performed for the Indian Point Unit 3 (IP3) reactor vessel (RV) to determine the stress and fatigue usage effects of Nuclear Steam Supply System (NSSS) operation at the revised operating conditions for the stretch power uprate (SPU).

5.1.1.2 Input Parameters and Description of Evaluation Performed

The RV structural evaluation assesses the effects of the revised operating parameters in Table 2.1-2 and RCS transients (see Section 3.1) on the most limiting locations with regard to ranges of stress intensity and fatigue usage factors in each of the regions as identified in the RV stress report and addendum. Prior to the SPU evaluation, the most recent vessel structural evaluation for IP3 was performed for the Measurement Uncertainty Recapture (MUR) Program. The design and operating parameters for the reactor vessel are revised as a result of the SPU in accordance with Table 2.1-2. The minimum vessel inlet temperature decreases from 542.2° to 517.3°F, thereby increasing the T_{cold} variations for plant loading and unloading transients. The SPU maximum vessel outlet temperature of 603.0°F is bounded by previous analyses, therefore not affecting the plant loading or unloading transients.

In addition, other design transients were judged more severe than their design basis counterparts. Loss-of-flow, one pump required consideration for the regions affected by T_{hot} in the SPU evaluation. Loss-of-load (LOL) and loss-of-flow, one pump in addition to plant loading and unloading required consideration for regions influenced by T_{cold}. Three pressure variations from the following transients also required consideration in the evaluation: step-load rejection, loss-of-flow, one pump, and reactor trip.

In addition to the above transient revisions, the evaluation also considered additional occurrences of the hydro-static test at 2500 psia for the RV. This was done to supplement the original stress report, which only considered 5 occurrences of hydro-static tests to ASME Section XI pressure test requirements subsequent to commercial operation. These pressure tests are known to occur more frequently than once every 8 to 10 years. Therefore, the evaluation considered at least 200 occurrences of the hydro-static test in the maximum cumulative usage factor (CUF) calculation for each RV region.

The revised RV and RV internals interface loads developed for the SPU were evaluated to ensure that they were acceptable.

The parameter cases in Table 2.1-2, the design transients discussed in Section 3.1, and the current design basis parameters and design transients are fully evaluated for the SPU. Reactor vessel operation in accordance with the IP3 SPU conditions is justified for the remainder of the operating license period.

5.1.1.3 Acceptance Criteria and Results of Evaluations

The acceptance criteria applicable to the evaluation are as follows:

- The maximum range of stress intensity must be less than three times the design stress intensity ($3S_m$) for each location.
- The cumulative fatigue usage factor must be less than unity (CUF < 1) for each location.

The RV main closure flange assembly, control rod drive mechanism (CRDM) housings, head adapter plugs, and outlet nozzles were evaluated for the effects of the increased T_{hot} variation during the transient for loss-of-flow, one pump. For regions affected by T_{hot} conditions, the maximum range of primary plus secondary stress intensity reported in the previous structural evaluation remain unchanged for the SPU. The CRDM housings are the only T_{hot} region that sees an increase in CUF, which is a slight increase to 0.124. The CUFs for other T_{hot} regions remain unchanged for the SPU.

The inlet nozzles, vessel wall transition, bottom head-to-shell juncture, core support pads, and instrumentation tubes were evaluated for the effects of the T_{cold} variations during transients for LOL, loss-of-flow, one pump, and plant loading and unloading. The vessel wall transition, core support pads, bottom head-to-shell juncture and instrumentation tubes all show slight increases in maximum ranges of stress intensity for the SPU. The maximum range of stress intensity for the inlet nozzles remains unchanged for the SPU. The CUF for the inlet nozzles, vessel wall transition, bottom head-to-shell juncture, and instrumentation tubes show slight increases, but remain well below the allowable limit for the SPU. The CUF for the core support pads remains unchanged for the SPU. The stress range and CUF results from this evaluation are summarized in Table 5.1-1.

The interface seismic and loss-of-coolant accident RV and reactor internal (LOCA RV/RI) loads for the IP3 SPU are all less than the corresponding faulted condition loads that have previously been considered in the IP3 RV stress report. Therefore, the loads are acceptable.

5.1.1.4 Conclusions

The maximum ranges of stress intensity are less than the allowable limit of $3S_m$ for all locations of the reactor vessel. The cumulative fatigue usage factors are less than unity for all locations, and the faulted condition interface loads are less than loads used in previous evaluations. In summary, the limits defined in the American Society of Mechanical Engineers (ASME) Section III (References 1 and 2) are satisfied and the SPU will not compromise the structural integrity of the IP3 RV.

5.1.2 RV Integrity

RV integrity is affected by any changes in plant parameters that affect neutron fluence levels or temperature and pressure transients. The neutron fluence projections resulting from the IP3 SPU have been evaluated to determine the potential effect on RV integrity. Typically, such an evaluation is performed by direct comparison of the neutron fluence projections from the analyses of record to the SPU neutron fluence projections. However, prior to the IP3 SPU, Westinghouse revised the current RV integrity analyses of record for IP3 as a part of the MUR Program. The only exception is the pressure-temperature limits, which were updated after the MUR Program. The updated reactor vessel integrity evaluations used neutron fluence projections that correspond to 3068 MWt. As such, the evaluations for the SPU discussed below build on the most recent analyses. More specifically, that includes the following evaluations:

- Assessment of the RV surveillance capsule removal schedule to confirm that the SPU fluence projections do not change the required number of capsules to be withdrawn from the IP3 RV.
- Review of the P-T limit curves to determine if the vessel fluence projections based on the SPU affect the applicability date.
- Review of the RT_{PTS} values to determine if the effects of the SPU fluence projections resulted in an increase in RT_{PTS} for the beltline materials in the IP3 RV at 27.1 effective full-power years (EFPYs), which is the estimated end of license (EOL).
- Review of the upper shelf energy (USE) values at 27.1 EFPY, which is the estimated EOL, to assess the effect of the SPU fluence projections.

The calculated fluences used in the SPU evaluation comply with Regulatory Guide (RG) 1.190 (Reference 3). These calculations are performed on a plant-specific basis, consistent with the methodology in RG 1.190. The net result of the SPU was an increase in projected fluence as

compared to the MUR Program fluence projections. This increased SPU fluence is the basis for the conclusions provided in the following subsections.

5.1.2.1 Surveillance Capsule Withdrawal Schedule

The revised SPU fluence projections have been used in the assessment of the current withdrawal schedule for IP3. A calculation of ΔRT_{NDT} at 27.1 EFPYs was performed to determine the number of capsules to be withdrawn for IP3. This calculation determined that the maximum ΔRT_{NDT} using the SPU fluences corresponding to 3216 MWt for IP3 at 27.1 EFPYs is greater than 200°F. These ΔRT_{NDT} values would require 5 capsules to be withdrawn from IP3 (Reference 4). This is consistent with the current withdrawal schedule. However, since the RV fluence projections increased, the withdrawal times are affected. The new withdrawal schedule is presented in Table 5.1-2.

5.1.2.2 Applicability of Heatup and Cooldown P-T Limit Curves

The IP3 *Technical Specifications* contain P-T limit curves for 34.7 EFPYs. These P-T limit curves were based on fluence values that correspond to a power level between 3068 and 3216 MWt. Therefore, the existing heatup and cooldown curves for 34.7 EFPY must be reduced to account for the higher fluence projections for the SPU. The reduced EFPY was determined by calculating the equivalent SPU EFPY that corresponds to the peak fluence used for the existing PT curves (1.13×10^{19} n/cm^2). This is normally a simple interpolation calculation. However, the fluence used to generate the existing PT curves is exactly equal to the SPU fluence projection at 34.0 EFPY. Thus, the applicability of the existing PT curves has been reduced 0.7 EFPY, to 34 EFPY (0.7 EFPY is equivalent to 8 months of operation).

5.1.2.3 Emergency Response Guideline Limits

The limiting material for IP3 is the lower shell plate B2803. The current peak inside surface RT_{NDT} value at 27.1 EFPY (EOL) associated with this material was calculated to be 262°F (see Table 5.1-3). The resulting Emergency Response Guidelines (ERG) category (see Table 5.1-4) is unchanged from the previous evaluation for the MUR Program to 3068 MWt.

5.1.2.4 Pressurized Thermal Shock

All beltline materials are expected to have RT_{PTS} values less than 270°F for plates, forgings, and longitudinal welds, and 300°F for circumferential welds. The pressurized thermal shock (PTS) calculations were performed for IP3 using the latest procedures required by the NRC (Reference 5). Based on the evaluation of PTS, all RT_{PTS} values will remain below the NRC screening criteria values using calculated SPU fluence projections that correspond to a SPU

power level of 3216 MW through 27.1 EFPYs (EOL) for IP3 as shown in Table 5.1-3. The change in RT_{PTS} due to the SPU, as compared to the MUR Program to 3068 MWt, is 5°F. This evaluation also determined that the limiting material is relatively close to the PTS screening criteria of 270°F and is expected to exceed this screening criteria at ~36 EFPY.

5.1.2.5 Upper Shelf Energy

All beltline materials have a USE greater than 50 ft-lb through 27.1 EFPY (EOL) as required by the Code of Federal Regulations (CFR) 10CFR50, Appendix G (Reference 6). The 27.1 EFPY (EOL) USE was predicted using the EOL 1/4 thickness (1/4t) SPU fluence projections that correspond to a SPU power level of 3216 MWt. Despite the fact that the vessel fluence projections have increase due to the SPU, as compared to the MUR Program to 3068 MWt, the change in USE decrease is zero. The USE values are presented in Table 5.1-5.

5.1.2.6 Inlet Temperature

RG 1.99, Revision 2 (Reference 7), which is also the basis for 10CFR50.61 (Reference 5), states that "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." The temperature range of 525°F to 590°F serves as the basis of the equations and tables that are used in all the RV internal analyses described herein. Therefore, the inlet temperature, which is the temperature to which the reactor vessel is subjected, must be maintained within this range to uphold all existing analyses.

5.1.2.7 Conclusions

The fluence projections used for the SPU, while considering actual power distributions incorporated to date, have increased versus the fluence projections developed for the MUR Program (to 3068 MWt). However, this increase has had minimal affect on the analyses of record for reactor vessel integrity since the PTS and USE remain within the acceptance criteria, the PTS curves had less than I EFPY decrease, the ERG category remains unchanged, and there were only minor withdrawal time changes to the withdrawal schedule. The regulatory criteria continue to be met for the SPU conditions. Therefore, there is no significant effect on RV integrity related to the SPU.

5.1.3 References

1. *ASME Boiler and Pressure Vessel Code, Nuclear Vessels,* American Society of Mechanical Engineers, New York, 1965 Edition through Winter 1965 Addenda.

2. *ASME Boiler and Pressure Vessel Code, Nuclear Power Plant Components,* American Society of Mechanical Engineers, New York (Appendix F and Appendix I Tables), 1974 Edition.

3. Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.*

4. ASTM E185-82, *Annual Book of ASTM Standards,* Section 12, Volume 12.02, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels."

5. 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, Federal Register,* Volume 60, No. 243, December 19, 1995.

6. 10CFR50, Appendix G, *Fracture Toughness Requirements.*

7. Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Materials,* Rev. 2, May 1988.

Table 5.1-1 Maximum Range of Stress Intensity and Cumulative Fatigue Usage Factor Results		
Location	Maximum Range of Stress Intensity	Cumulative Fatigue Usage Factor
CRDM Housings	[	]a,c,e
Main Closure		
Closure Head Flange		
Vessel Flange		
Closure Studs		
Outlet Nozzles and Supports		
Nozzle		
Inlet Nozzles and Supports		
Nozzle		
Vessel Wall Transition		
Core Support Pads		
Bottom Head-to-Shell Juncture		
Instrumentation Tubes		
Head Adapter Plugs		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.1-2 Recommended Surveillance Capsule Withdrawal Schedule with SPU Fluence Projections				
Capsule	Capsule Location	Lead Factor	Withdrawal EFPY(1)	Fluence (n/cm^2)(2)
T	40°	3.43	1.4	2.63×10^{18}
Y	40°	3.49	3.2	6.92×10^{18}
Z	40°	3.48	5.5	1.04×10^{19}
S	40°	3.46	(3)	(3)
X	4°	1.52	15.5(4)	8.74×10^{18}(4)
V	4°	1.52	EOL(5,6)	(5,6)
W	4°	1.52	EOL(5,6)	(5,6)
U	4°	1.52	EOL(5,6)	(5,6)

Notes:

1. Effective full power years (EFPYs) from plant startup.
2. Updated during IP3 SPU.
3. IP3 tried to remove capsule S in May of 2001; however, the capsule was not retrievable.
4. Capsule X was removed in May of 2003 at 15.5 EFPY, which is the criteria for the 4th surveillance capsule removal. This capsule has been tested, and the fluence on the capsule has yet been verified.
5. If IP3 is following a withdrawal schedule for EOL (27.1 EFPY), then it is recommended to remove the 5th and standby capsules any time after 16.1 EFPY, but not to exceed 27.1 EFPY (EOL). This would satisfy the ASTM E 185-82 requirement for withdrawal @ EOL, not less than once or greater than twice the peak EOL vessel fluence. The projected fluence on the capsules will be between 9.22×10^{18} n/cm^2 (1 times the peak EOL vessel fluence) and 1.844×10^{19} n/cm^2 (2 times the peak EOL vessel fluence), depending on the exact withdrawal time. The standby capsules should also be withdrawn and placed in storage. Alternative fluence measuring techniques must be applied once standby capsules are removed.
6. If IP3 is following a withdrawal schedule for license extension (45.3 EFPY), then it is recommended to remove the 5th and standby capsules any time after 28.2 EFPY, but not to exceed 45.3 EFPY (EOL). This would satisfy the ASTM E 185-82 requirement for withdrawal @ EOL, not less than once or greater than twice the peak EOL vessel fluence. The projected fluence on the capsules will be between 1.48×10^{19} n/cm^2 (1 times the peak EOL vessel fluence) and 2.96×10^{19} n/cm^2 (2 times the peak EOL vessel fluence), depending on the exact withdrawal time. The standby capsules should also be withdrawn and placed in storage. Alternative fluence measuring techniques must be applied once the standby capsules are removed.

Table 5.1-3

RT_{PTS} Calculations for IP3 Beltline Region Materials at 27.1 EFPY with (3216 MWt) SPU Fluences

Material	Fluence (n/cm^2, E>1.0 MeV)	FF	CF (°F)	ΔRT_{PTS}(1) (°F)	Margin (°F)	$RT_{NDT(U)}$(2) (°F)	RT_{PTS}(3) (°F)
Intermediate Shell Plate	0.992	0.998	137	136.7	34	5	176
Intermediate Shell Plate	0.992	0.998	152	151.7	34	-4	182
Intermediate Shell Plate	0.992	0.998	136	135.7	34	17	187
Lower Shell Plate	0.992	0.998	128	127.7	34	49	211
Lower Shell Plate	0.992	0.998	150	149.7	34	-5	179
Lower Shell Plate	0.992	0.998	160	159.9	34	74	268
→ Using S/C Data	0.992	0.998	170.9	170.6	17(4)	74	**262**
Intermediate and Lower Shell Weld Longitudinal Weld Seams (heat 34B009)	0.992	0.998	**224**	223.6	65.5	-56	233
Intermediate to Lower Shell Circumferential weld Seams (heat 13253)	0.992	0.998	**189**	188.6	56	-54	191

Notes:

1. ΔRT_{PTS} = CF * FF
2. Initial RT_{NDT} values are measured values except for the intermediate and lower longitudinal welds.
3. $RT_{PTS} = RT_{NDT(U)} + \Delta RT_{PTS}$ + Margin (°F)
4. Using credible surveillance data.

Table 5.1-4 ERG Pressure-Temperature Limits	
Applicable RT_{NDT} (ART) Value [1]	**ERG P-T Limit Category**
RT_{NDT} < 200°F	Category I
200°F < RT_{NDT} < 250°F	Category II
250°F < RT_{NDT} < 300°F	Category IIIb

Notes:

1. Longitudinally oriented flaws are applicable only up to 250°F; the circumferentially oriented flaws are applicable up to 300°F.

Table 5.1-5

Predicted 27.1 EFPY USE Calculations for all the Beltline Region Materials with Bounding (3216 MWt) SPU Fluences

Material	Weight % of Cu	1/4T EOL Fluence (10^{19} n/cm^2)	Unirradiated USE (ft-lb)	Projected USE Decrease (%)[1]	Projected EOL USE (ft-lb)
Intermediate Shell Plate B2802-1	0.20	0.550	102	25	77
Intermediate Shell Plate B2802-2	0.22	0.550	97	27	71
Intermediate Shell Plate B2802-3	0.20	0.550	95	25	71
Lower Shell Plate B2803-1	0.19	0.550	72	24	55
Lower Shell Plate B2803-2	0.22	0.550	94	27	69
Lower Shell Plate B2803-3	0.24	0.550	68	18[2]	55[2]
Intermediate and Lower Shell Weld Longitudinal Weld Seams (heat 34B009)	0.19	0.550	112	28	80
Intermediate to Lower Shell Circumferential weld Seams (heat 13253)	0.22	0.550	111	31	77

Notes:

1. Values are deduced from Figure 6.3-1: Regulatory Guide 1.99, Revision 2, predicted decrease in upper shelf energy as a function of copper and fluence.
2. Using surveillance capsule data from previously analyzed capsules T, Y and Z.

5.2 Reactor Pressure Vessel System

Evaluations and analyses were performed to assess the effect on the reactor internals components for a stretch power uprate (SPU) at Indian Point Unit 3 (IP3) to a Nuclear Steam Supply System (NSSS) power level of 3230 MWt (core power of 3216 MWt) for the design life of the plant. The analyses/evaluations were performed with 15 x 15 fuel as described in Section 7 of this document.

5.2.1 Introduction

The Reactor Pressure Vessel (RPV) System consists of the reactor vessel, reactor internals, fuel, and control rod drive mechanisms (CRDMs). The reactor internals support and orient the reactor core fuel assemblies and control rod assemblies, absorb control rod assembly dynamic loads, and transmit these and other loads to the reactor vessel. The reactor vessel internal components support in-core instrumentation and also direct coolant flow through the fuel assemblies (core), to provide adequate cooling flow to the various internals structures. The internals are designed to withstand forces due to structure deadweight, fuel assembly pre-load, control rod assembly dynamic loads, vibratory loads, and earthquake accelerations.

Operating a plant at conditions (power and temperature) other than those considered in the original design requires that the interface between the Reactor Vessel System and the fuel be thoroughly addressed to ensure compatibility and to ensure that the structural integrity of the reactor vessel-internals-fuel system is not adversely affected. In addition, thermal-hydraulic analyses are required to determine plant-specific core-bypass flows, pressure drops, and upper head temperatures to provide input to the loss-of-coolant accident (LOCA) and non-LOCA safety analyses, and to NSSS performance evaluations.

The principal areas affected by changes in system operating conditions are:

- Reactor internals system thermal-hydraulic performance
- Rod control cluster assembly (RCCA) scram performance
- Mechanical system evaluations
- Reactor internals system structural response and integrity
- Bottom-mounted instrumentation (BMI) guide tubes and flux thimbles

The major components and features of the reactor internals system for IP3 are summarized as follows. The lower core support assembly consists of the lower support plate, lower support columns, and lower core plate and core barrel, which support the fuel assemblies on the sides and at the bottom. The radial support system, the head-vessel alignment pins, and special temporary guide studs attached to the vessel guide and align the lower core support assembly

during insertion into the reactor vessel. The hold-down spring rests on top of the flange of the lower core support assembly. The upper core support assembly consists of the upper support plate, upper support columns, and upper core plate, and rests on top of the hold-down spring. The guidance and alignment of the upper core support assembly during its insertion are provided by the head-vessel alignment pins, the upper core plate alignment pins in the core barrel assembly, and the special temporary guide studs attached to the vessel. The alignment of the core fuel assemblies is provided through the engagement of the lower core plate fuel pins into the bottom of the fuel assemblies and the upper core plate fuel pins into the top of the fuel assemblies. The vessel upper head compresses the hold-down spring, providing joint preload.

The core barrel, which is part of the lower core support assembly, provides a flow boundary for the reactor coolant. When the primary coolant enters the reactor vessel, it impinges on the side of the core barrel and is directed downward through the annulus formed by the gap between the outside diameter of the core barrel and the inside diameter of the vessel. The flow then enters the lower plenum area between the bottom of the lower support plate and the vessel bottom head and is redirected upward through the core. After passing through the core, the coolant enters the upper core support region and then proceeds radially outward through the reactor vessel outlet nozzles. The perforations in the various components, such as the lower support plate, control and meter the flow through the core.

This section summarizes the work performed to assess the effect on the RPV/internals system of the SPU at IP3.

Input Parameters and Assumptions

The principal input parameters used in the analysis of the reactor internal components and RPV system are the NSSS design parameters developed for the SPU (see Table 2.1-2). For structural analysis evaluations, the NSSS design transients discussed in Section 3 were considered. This evaluation considered a full core of 15 x 15 fuel with intermediate flow mixers (IFMs) and with thimble plugging devices in place.

Operating Parameters

The operating parameters (pressure, temperature, flow, and power level) shown in Table 2.1-2 were used in this evaluation. Also, the design transients discussed in Section 3 were used in this evaluation.

A full core of Westinghouse 15 x 15 fuel with IFMs was used in the analysis.

Description of Analyses and Evaluations

Westinghouse has performed evaluations and analyses to assess the effect of the SPU on the RPV/internals system of IP3. The description of various analyses and evaluations are given in the individual subsections, 5.2.2 through 5.2.5.

Acceptance Criteria

The acceptance criteria are listed in each individual section. However, some of the most important acceptance criteria are grouped together and are as follows:

- The design core bypass flow limit with the thimble-plugging devices in place is 5.5 percent of the total vessel flow rate.
- Hydraulic lift forces on the reactor internals must be limited so that the internals remain seated and stable.
- For the structural and fatigue evaluations of the various reactor internal components, the cumulative fatigue usage factors must be less than 1.0 for the most critically stressed members.

5.2.2 Thermal-Hydraulic System Evaluations

5.2.2.1 System Pressure Losses

The principal Reactor Coolant System (RCS) flow route through the RPV System at IP3 begins at the inlet nozzles. At this point, flow turns downward through the reactor vessel and core barrel annulus. After passing through this downcomer region, the flow enters the lower reactor vessel dome region. This region is occupied by the internals energy absorber structure, lower support columns, BMI columns, and supporting tie plates. From this region, flow passes upward through the lower core plate and into the core region. After passing up through the core, the coolant flows into the upper plenum, turns, and exits the reactor vessel through the four outlet nozzles. The upper plenum region contains support columns and RCCA guide columns.

A key area in evaluation of core performance is the determination of hydraulic behavior of coolant flow within the reactor internals system, that is, vessel pressure drops, core bypass flows, RPV fluid temperatures, hydraulic lift forces, and baffle joint momentum flux. The pressure loss data are necessary inputs to the LOCA and non-LOCA safety analyses and to overall NSSS performance calculations. The hydraulic forces are considered in the assessment

of the structural integrity of the reactor internals, core clamping loads generated by the internals holddown spring, and the stresses in the reactor vessel closure studs.

The THRIVE computer code was used to perform this evaluation by solving the mass and energy balances for the reactor internals fluid system. This THRIVE analysis determined the distribution of pressure and flow within the reactor vessel, internals, and the reactor core. Results were obtained with a full core of Westinghouse 15 x 15 fuel with IFM grids, thimble plugs in place, and at RCS conditions, as summarized in Table 2.1-2.

5.2.2.2 Bypass Flow Analysis

Description of Analyses

Bypass flow is the total amount of reactor coolant flow bypassing the core region and was not considered effective in the core heat transfer process. Variations in the size of some of the bypass flow paths, such as gaps at the outlet nozzles and the core cavity, occur during manufacturing or change due to fuel assembly changes. Plant-specific, as-built dimensions were used to demonstrate that the bypass flow limits were not exceeded. Therefore, analyses were performed to estimate core bypass flow values to either show that the design bypass flow limit for the plant will not be exceeded, or to determine a revised design core bypass flow.

The present design core bypass flow limit is 5.5 percent of the total reactor vessel flow with the thimble-plugging devices in place. This evaluation shows that the design value of 5.5 percent was maintained at the RCS conditions described in Table 2.1-2. The principal core bypass flow paths are described in the following paragraphs.

Baffle-Barrel Region

The current reactor vessel internals configuration incorporates downward coolant flow in the region between the core barrel and the baffle plates. In this configuration, a portion of the coolant exits the reactor vessel inlet nozzle and flows downward in the annulus between the vessel and core barrel. The downward flow passes over the thermal shield to the lower plenum, turns, and flows up through the core region. A portion of this flow enters the baffle-barrel region, which consists of vertical baffle plates that follow the periphery of the core. These are joined to the core barrel by horizontal former plates spaced along the elevation of the baffle plates. At IP3, all but the top former plates have flow holes machined in them. Between the top two former levels there are flow holes in the core barrel. Some flow from the vessel and barrel down-comer is diverted through these flow holes, then travels downward through the lower former levels. Most of this baffle/barrel region flow continues down to the top of the lower core plate. There it passes under the baffle plates and into the bottom of the core.

Some fraction of the baffle-barrel plates leaks between the baffle plates and, therefore, is considered as core bypass flow.

Vessel Head Cooling Spray Nozzles

These nozzles provide flow paths between the reactor vessel and core barrel annulus and the fluid volume in the vessel closure head region above the upper support plate. A fraction of the flow that enters the vessel inlet nozzles and into the vessel and barrel downcomer passes through these nozzles and into the vessel closure head region. These flow paths allow circulation of a small fraction of the cold leg coolant into the upper head region of the reactor vessel.

Core Barrel - Reactor Vessel Outlet Nozzle Gap

At IP3, some of the flow that enters the vessel and barrel downcomer leaks through the gaps between the core barrel outlet nozzles and the reactor vessel outlet nozzles and merges with the vessel outlet nozzle flow. Since the lower reactor internals are designed to be removable from the reactor vessel, a small circumferential gap exists at each of the outlet nozzle locations. While the gap is designed to be very small and closes down somewhat at operating conditions due to the differential coefficient of thermal expansion between the reactor internals and the reactor vessel, there is some amount of flow that leaks directly from the vessel inlet/downcomer region and out through these nozzle gaps.

Fuel Assembly - Baffle Plate Cavity Gap

The baffle plates surround the reactor fuel assemblies or core region. The gap between the peripheral fuel assemblies and the baffle plates is defined as the core cavity region. This gap provides the core bypass flow path between the peripheral fuel assemblies and the core baffle plates.

Fuel Assembly Thimble Tubes

Thimble tubes are used as paths for the insertion and removal of control rods, thimble-plugging devices, and various core components such as burnable absorbers. These tubes are physically part of each fuel assembly and flow within them is partially effective in removing core heat. However, such flow was analytically not considered to be effective in heat removal, and was consequentially considered to be part of the core bypass flow.

Bypass Flow Analysis Results

Fuel assembly hydraulic characteristics and system parameters, such as inlet temperature, reactor coolant pressure, and flow were used in conjunction with the THRIVE code to determine the effect of SPU RCS conditions on the total core bypass flow. The calculated core bypass flow value was [ ]^{a,c,e} percent with the thimble-plugging devices in place at the RCS conditions of Table 2.1-2. Therefore, the design core bypass flow value of 5.5 percent with thimble-plugging devices in place , was confirmed to remain bounding.

5.2.2.3 Hydraulic Lift Forces

An evaluation was performed to estimate hydraulic lift forces on the various reactor internal components for the SPU parameters shown in Table 2.1-2. This was done to show that the reactor internals assembly would remain seated and stable for all conditions. The evaluation concluded that the IP3 reactor internals will remain seated and stable for the SPU RCS conditions.

5.2.2.4 Momentum Flux and Fuel Rod Stability

Baffle jetting can be caused by a hydraulically induced instability or vibration of fuel rods, induced by a high velocity jet of water. This jet can be created by high-pressure water being forced through gaps between the baffle plates that surround the core. The baffle-jetting phenomenon could lead to fuel-cladding damage.

At IP3 with SPU conditions and 15 x 15 fuel, the THRIVE evaluations showed that the momentum flux margins were within the design limits and, therefore, baffle jetting is not predicted for IP3 at SPU conditions.

5.2.2.5 Upper Head Fluid Temperatures

The average temperature of the primary coolant fluid that occupies the reactor vessel closure head volume is an important initial condition for certain dynamic LOCA analyses, therefore, it was necessary to determine the upper head temperature for the changes in the RCS conditions. Determination of upper head temperature was derived from the THRIVE evaluations used to assess the core bypass flow. The THRIVE code models the interaction among the different flow paths into and out of the closure head region. Based on this interaction, it calculated the core bypass flow into the head region and the average head fluid temperature based on the different flow path conditions. The IP3 upper head operates at a temperature closer to T_{hot}. For IP3, the upper head region best-estimate mean fluid temperature was calculated to be a maximum of

592.9°F for the RCS conditions provided in Table 2.1-2. The effect of the change in upper head temperature is evaluated in Section 5.10 of this report.

5.2.3 RCCA Scram Performance Evaluation

The RCCAs represent perhaps the most critical interface between the fuel assemblies and the other internal components. It is imperative to show that the SPU RCS conditions will not adversely affect the operation of the RCCAs, either during accident conditions or during normal operation.

The IP3 RCCA drop-time performance assessment involved the following steps:

- Obtained actual plant drop time-to-dashpot entry data at no-flow and full-flow conditions for each RCCA location.

- Developed an analytical model of the plant's driveline configuration and system operating conditions corresponding to those measurements. A driveline was considered to be that subset of components affecting RCCA drop time. These components were the fuel, upper core plate, upper and lower guide tubes, upper support plate, reactor closure head penetration, thermal sleeve, CRDM, rod travel housing, and the RCCA/drive rod assembly. The system operating conditions included temperature, pressure, and flow. The analytical model included values for parameters that describe geometry of driveline components, component mechanical interaction relationships, hydraulic resistances of flow paths, RCCA/drive rod assembly weight, and system operating conditions.

- Used a coded algorithm previously developed by Westinghouse, with the analytical model, to correlate the model to the plant-measured drop times. This algorithm, titled DROP, has been used for this analysis since the original plant design. The DROP algorithm solves Newton's second law of motion. This law states:

$$\Sigma F = (W/g) \times (dV/dt)$$

where:

ΣF	=	Sum of various forces acting on the RCCA/drive rod assembly at any time (t)
W	=	total weight of RCCA/drive rod assembly

g = acceleration due to gravity (32.2 ft/sec^2)

V = assembly velocity (ft/sec)

t = drop time after CRDM latch release of drive rod (sec)

The correlation involved adjustment of specific code input parameters:

— Characterized RCCA drop performance from no-flow (0 percent) through full-flow (100 percent) based on zero-flow and full-flow core average drop-time measurements, and

— Isolated and accounted for the effects of variations in driveline mechanical interference drag force under normal conditions, and variations in driveline flows across the core, based on core-maximum drop time measurements at zero-flow and full-flow, respectively.

- Adjusted the model (that is, DROP input parameter values) to account for the new system operating conditions being considered due to SPU. Also, conservatively accounted for:

— Component geometric design tolerances

— Hydraulic performance uncertainties (related to fuel assembly hydraulic resistance, guide tube/RCCA wear, and reactor coolant flow rate)

— Abnormal environmental conditions (particularly seismic events)

- Assessed the effect of such changes in driveline components and/or primary system operating conditions on the limiting RCCA drop-time characteristics used in the plant accident analyses. These limiting characteristics were the most severe drop time-to-dashpot entry and normalized RCCA drop time position-versus-time relationship estimated based on the tolerances, uncertainties, and abnormal environmental conditions identified above.

The analysis determined the effect of the conditions shown in Table 2.1-2 on the limiting RCCA drop time. The maximum estimated RCCA drop time with the seismic allowance was calculated to be 1.95 seconds to the top of dashpot. This value is less than the current analysis limit of 2.7 seconds. The calculated RCCA drop time value at the SPU power level without a seismic allowance is 1.68 seconds, which is less than the *Technical Specification* limit of 1.8 seconds.

5.2.4 Mechanical System Evaluations

The RCS mechanical response to auxiliary line breaks of a LOCA transient is performed in three steps. First the RCS is analyzed for the effects of loads induced by normal operation, which includes thermal, pressure, and deadweight effects. From this analysis, the mechanical forces acting on the RPV, which would result from release of equilibrium forces at the break locations, are obtained. In the second step, the loop mechanical loads and reactor internals hydraulic forces are simultaneously applied, and the RPV displacements due to the LOCA are calculated. Finally, the structural integrity of the reactor coolant loop (RCL) and component supports to deal with the LOCA are evaluated by applying the calculated reactor vessel displacements to a mathematical model of the RCL (see Section 5.4). Thus, the effects of vessel displacements upon the loop and reactor vessel and internals were evaluated.

5.2.4.1 LOCA and Seismic Loads

The RPV LOCA system mathematical model of IP3 was a three-dimensional (3-D), non-linear, finite element model that represented the dynamic characteristics of the reactor vessel and its internals in the six geometric degrees of freedom. The model was developed using the WECAN computer code. The WECAN computer code (or predecessor codes) was used for this analysis since the original plant design.

The WECAN computer code, which is used to determine the response of the reactor vessel and its internals, is a general-purpose finite element code. In the finite element approach, the structure is divided into a finite number of members or elements. The inertia and stiffness matrices, as well as the force array, are first calculated for each element in the local coordinates. Employing appropriate transformation, the element global matrices and arrays are then computed. Finally, the global element matrices and arrays are assembled into the global structural matrices and arrays, and used for dynamic solution of the differential equation of motion for the structure.

To evaluate the effect of changes in RCS conditions on the dynamic response of the RPV System, LOCA analyses were performed to generate core plate motions and the reactor vessel and internals interface loads. The core plate motions were then used to evaluate the structural integrity of the core. Since application of leak-before-break (LBB) methodology has been licensed for the main coolant loop, consideration of breaks in the main coolant loop was not required for structural evaluations (see subsection 5.4.2). The next limiting breaks considered were the branch line breaks. The hydraulic LOCA forces for the breaks listed below were used in the reactor vessel LOCA analysis:

- Accumulator line (cold leg)
- Pressurizer surge line (hot leg)

Following a postulated LOCA, forces were imposed on the reactor vessel and its internals. These forces resulted from the release of the pressurized primary system coolant and, for auxiliary pipe breaks, from the disturbance of the mechanical equilibrium in the piping system prior to the rupture. The release of pressurized coolant resulted in traveling depressurization waves in the primary system. These depressurization waves were characterized by a wavefront with low pressure on one side and high pressure on the other. The wavefront translated and reflected throughout the primary system until the system was completely depressurized. The rapid depressurization resulted in transient hydraulic loads on the mechanical equipment of the system.

The LOCA loads applied to the RPV System consisted of: reactor internal hydraulic loads (vertical and horizontal), and RCL mechanical loads. All the loads were calculated individually and combined in a time-history manner.

The MULTIFLEX computer code calculated the hydraulic transients within the entire primary coolant system. It considered sub-cooled, transition, and two-phase (saturated) blowdown regimes. The MULTIFLEX program uses the method of characteristics to solve the conservation laws, and assumes one-dimensionality of flow and homogeneity of the liquid-vapor mixture.

The MULTIFLEX code considers a coupled fluid-structure interaction by accounting for the deflection of constraining boundaries, which are represented by separate spring-mass oscillator systems. A beam model of the core support barrel was developed from the structural properties of the core barrel. In this model, the cylindrical barrel was vertically divided into various segments and the pressure/wall motions were projected onto the plane parallel to the inlet nozzle on the loop with the postulated auxiliary line pipe break. Horizontally, the barrel was divided into ten segments, with each segment consisting of three separate walls. The spatial pressure variation at each time step was transformed into ten horizontal forces, which acted on the ten mass points of the beam model. Each flexible wall was bounded on either side by a hydraulic flow path. The motion of the flexible walls was determined by solving the global equations of motion for the masses representing the forced vibration of an undamped beam.

The severity of a postulated break in a reactor vessel was related to two factors: the distance from the reactor vessel to the break location and the break opening area. The nature of the reactor vessel decompression following a LOCA, as controlled by the internals structural configuration previously discussed, resulted in larger reactor internal hydraulic forces for pipe breaks in the cold leg than in the hot leg (for breaks of similar area and distance from the RPV). Pipe breaks farther away were less severe because the pressure wave attenuated as it propagated toward the reactor vessel. Therefore, pipe breaks at the reactor vessel inlet nozzle were more severe because of the absence of pressure wave attenuation and the structural

configuration of the core. In general, the auxiliary line breaks, like the accumulator line and the pressurizer surge line breaks, were not as severe as the main line breaks, such as RPV inlet nozzle or RCP outlet nozzle break.

The results of reactor vessel displacements and the impact forces calculated at vessel and internals interfaces were used to evaluate the structural integrity of the reactor vessel and its internals.

The core plate motions for both breaks were used in the fuel grid analysis to confirm the structural integrity of the fuel.

Seismic Analyses

The non-linear time-history seismic analyses of the RPV System included the development of the system finite element model and the synthesized time-history accelerations.

Similar to the response during LOCA, the RPV System seismic model included sub-models of the reactor vessel, nozzles, internals, fuel, and CRDMs. The WECAN finite element model described for LOCA was modified to include the fluid-structure interaction in the RPV model for the seismic safe shutdown earthquake (SSE) time history evaluations. The WECAN reactor vessel-internals-fuel assembly model incorporated the effects of fluid-structure interaction in the downcomer region via hydro-dynamic mass matrices between two concentric cylinders (between the core barrel and reactor vessel). The fluid-structure interaction in the seismic analysis was different from that included in the LOCA analysis. In the LOCA analysis, the fluid-structure interaction was included through the MULTIFLEX code; whereas in the seismic analysis, the fluid-structure interaction in the downcomer region (between the core barrel and reactor vessel) was incorporated through the hydro-dynamic mass matrices. The mass matrices with off-diagonal terms were incorporated between nodes on the core barrel and reactor vessel shell.

For a time-history response of the RPV and its internals under seismic excitation, synthesized time-history accelerations were required. The synthesized time-history accelerations for the RPV System analysis were based on the applicable response spectra. The records of a real earthquake, TAFT, were the basis for the synthesized time history accelerations. The spectral characteristics of the synthesized time-history accelerations were similar to the original 'TAFT' earthquake records. The resulting north-south, east-west, and vertical acceleration time-history accelerations were generated for the SSE events.

The results of the system seismic analysis included time-history displacements and impact forces for all the major components. The reactor vessel displacements and the impact forces

calculated at vessel and internals interfaces were used to evaluate the structural integrity of the reactor vessel and its internals. The core plate motions were used in the fuel grid analysis to confirm the structural integrity of the fuel.

5.2.4.2 Flow-Induced Vibrations

Flow-induced vibrations (FIVs) of pressurized water reactor (PWR) internals have been studied by Westinghouse for a number of years. The objective of these studies was to show that the structural integrity and reliability of reactor internal components are acceptable for plant operating conditions. These efforts have included in-plant tests, scale-model tests, as well as tests in fabricators' shops and bench tests of components, along with various analytical investigations. The results of these scale-model and in-plant tests indicate that the vibrational behavior of two-, three-, and four-loop plants is essentially similar, and the results obtained from each of the tests complement one another and make possible a better understanding of the FIV phenomena.

Based on the analysis for the IP3 reactor internals, the response due to FIVs was extremely small and well within the allowable levels based on the high-cycle endurance limit for the materials.

5.2.4.3 RCCA Insertion Evaluation

To assess the feasibility of crediting the RCCA insertion during a postulated faulted event, the loads on the guide tubes were calculated. These loads included the dynamic loads derived from the RPV System response, subsection 5.2.3.1, the acoustic loads and the cross flow loads during postulated LOCA events. These loads were combined using the square root sum of the squares (SRSS) method. The postulated LOCA events were the two limiting breaks stated above, namely, the pressurizer surge line break and the accumulator line break.

The evaluations showed that the maximum LOCA loads were within the allowable loads that were established for 15 x 15 type guide tubes to ensure that the RCCA scram time would be acceptable. Consequently, the RCCA insertion for the IP3 plant could be credited following a faulted-condition event. The evaluation also showed that the maximum seismic load is within the allowable load for the 15 x 15 guide tubes. Therefore, control rod insertion is also ensured during a faulted seismic event.

5.2.5 Structural Evaluation of Reactor Internal Components

In addition to supporting the core, a secondary function of the reactor vessel internals assembly is to direct coolant flows within the vessel. While directing primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and the internals structural components. Some of the parameters influencing the mechanical design of the internals lower assembly are the pressure and temperature differentials across its component parts and the flow rate required to remove heat generated within the structural components due to radiation (for example, gamma heating). The configuration of the internals provides adequate cooling capability. The thermal gradients resulting from gamma heating and core coolant temperature changes are maintained below acceptable limits within and between the various structural components.

Structural evaluations demonstrated that the structural integrity of reactor internal components was not adversely affected either directly by the SPU RCS conditions and transients, or by secondary effects on reactor thermal-hydraulic or structural performance. Heat generated in reactor internal components, along with the various fluid temperature changes, resulted in thermal gradients within and between components. These thermal gradients resulted in thermal stresses and thermal growth, which must be considered in the design and analysis of the various components.

The IP3 reactor internals were designed to meet the intent of Subsection NG of the *ASME Boiler and Pressure Vessel Code*, Section III (Reference 1). A plant-specific stress report on the reactor internals was not required. The structural integrity of the IP3 reactor internals design has been ensured by analyses performed on both generic and plant-specific bases. These analyses were used as the basis for evaluating critical IP3 reactor internal components for SPU RCS conditions and revised design transients.

5.2.5.1 Lower Core Plate

Structural evaluations were performed to demonstrate that the structural integrity of the lower core plate was not adversely affected either by the SPU RCS conditions or by secondary effects on reactor thermal-hydraulic or structural performance. For this lower core plate evaluation, the criteria described in Section III, Subsection NG of the ASME Code (Reference 1) were used.

Primarily because of the higher gamma heating rates associated with the SPU conditions, the lower core plate is one of the most critically stressed components in the reactor internals assembly. The conclusion of these evaluations was that the structural integrity of the lower core plate was maintained. The SPU RCS conditions resulted in acceptable margins of safety and fatigue usage factors for all ligaments under all loading conditions.

5.2.5.2 Upper Core Plate Evaluations

The upper core plate positions the upper ends of the fuel assemblies and the lower ends of the control rod guide tubes, thus serving as the transitioning member for the control rods in entry and retraction from the fuel assemblies. It also controls coolant flow exiting the fuel assemblies and serves as a boundary between the core and the exit plenum. The upper core plate is restrained from vertical movement by the upper support columns, which are attached to the upper support plate assembly. Four equally spaced core plate alignment pins restrain lateral movement.

An evaluation was performed to determine the effect of SPU on the structural integrity of the upper core plate. This evaluation concluded that the upper core plate was structurally adequate for the SPU RCS conditions.

5.2.5.3 Baffle-Barrel Region Components

The IP3 lower internals assembly consists of a core barrel into which baffle plates are installed, supported by interconnecting former plates. A lower core support structure is provided at the bottom of the core barrel and a thermal shield surrounds the core barrel. The components comprising the lower internals assembly are precision-machined. The baffle and former plates are bolted into the core barrel. The reactor vessel internals configuration for IP3 uses downward flow in the barrel-baffle region.

Core Barrel Evaluation

The thermal stresses in the core-active region of the core-barrel shell are primarily due to temperature gradients through the thickness of the core-barrel shell. Evaluations were performed to determine the thermal bending and skin stresses in the core barrel for the SPU RCS conditions. These evaluations indicated that the fatigue usage factor, based on all normal/upset conditions, was well below the allowable value of 1.0. From these conservative results, it was concluded that the core barrel was structurally adequate for the SPU RCS conditions.

Baffle-Barrel Bolt Evaluation

The bolts were evaluated for loads resulting from hydraulic pressure, seismic loads, preload, and thermal conditions. The temperature difference between baffle and barrel produced the dominant loads on the baffle-former bolts. Hydraulic pressure and seismic loads produced the primary stresses, whereas bolt preloading and thermal conditions produced the secondary stresses. The SPU RCS conditions did not affect deadweight or preload forces.

Since these bolts are qualified by test, the evaluation of the revised loads consisted of demonstrating that the loads associated with the SPU RCS conditions were bounded by the loads qualified in the test program. Therefore, it was concluded that the baffle-former and barrel-former bolts were structurally adequate for the SPU RCS conditions.

5.2.5.4 Additional Component Evaluations

A series of assessments were performed on reactor internal components that were not significantly affected by the SPU (and the resulting internal heat generation rates), but were affected by the SPU conditions due to primary loop design transients. These components were:

- Lower support columns
- Instrumentation columns
- Core-barrel-to-lower-support-plate junction
- Thermal shield
- Top hat structure

The results of these assessments, shown in Table 5.2-1, demonstrated that the above listed critical components were structurally adequate for the SPU RCS conditions and the fatigue usage factors were less than 1.0.

5.2.6 BMI Guide Tubes and Flux Thimbles

The BMI guide tubing at IP3 was designed according to the 1970 version of the ASME Code, Section III, Class 1 (Reference 1). The 1970 version of the ASME Code does not include explicit acceptance criteria for the stress evaluation, therefore, Westinghouse performed a quantitative evaluation of the potential effects of the SPU on the IP3 BMI guide tubes based on acceptance criteria from the 1977 version of the ASME Code, Section III, Class 2 rules of NC-3650 (Reference 2). The flux thimbles are qualified as part of the BMI guide tubing. In summary, the use of the 1977 ASME Code criteria is appropriate for this quantitative SPU evaluation, does not change the 1970 ASME design basis for the IP3 BMI guide tubes, and is more conservative than related criteria in ANSI B31.1 (Reference 3).

5.2.6.1 Qualification of BMI Tubing and Flux Thimbles

The evaluation of the IP3 BMI guide tubing and flux thimble due to the SPU conditions was evaluated to ensure that the BMI guide tubes met allowables.

There are three areas that need to be considered for the reconciliation of BMI guide tubing qualification. They are:

- Pressure increase during transients
- Temperature increase during transients and new core inlet temperature from the SPU parameters (see Table 2.1-2)
- Reactor vessel bottom dome displacement during a LOCA

The BMI guide tubing is qualified for 2500 psia and 550°F, so if the service temperature or pressure values are different than the qualified values, the stress values in the guide tubing must be re-evaluated. Also, the reactor vessel displacement at the bottom dome, if different, must be evaluated to determine the stress in the guide tubing.

The evaluation used inputs described in Sections 2 and 3 of this report for temperatures and design transients. Equations 8, 9, 10, 11, and 9-faulted from ASME Section III paragraph NC-3650 (Reference 1) were re-evaluated for the above three changes.

5.2.7 Conclusions

Analyses/evaluations have been performed to assess the effect of changes due to the SPU. The results of these analyses/evaluations demonstrated:

- The use of the design core bypass flow value of 5.5 percent of the total vessel flow rate with thimble-plugging devices in place was confirmed for the SPU RCS conditions.
- The IP3 reactor internals assemblies will remain seated and stable at the SPU RCS conditions.
- The RCCA performance evaluation indicated that the current 2.7-second RCCA drop-time from gripper release of the drive-rod-to-dashpot entry limit was satisfied at the SPU RCS conditions and remained conservatively applicable.
- The baffle plate momentum flux margins of safety due to SPU RCS conditions were relatively unchanged from present conditions for mechanical design flow, and remained acceptable.

- The evaluations indicated that the SPU RCS conditions will not adversely affect the response of reactor internals systems and components due to seismic/LOCA excitations and FIVs.

- The evaluations of the critical reactor internal components indicated that the structural integrity of the reactor internals was maintained at the SPU RCS conditions. Limiting CUFs were all shown to be less than 1.0.

- The stresses in the BMI guide tubing were within the allowables and meet the requirements of ASME Section III, paragraph NC-3650 (Reference 1). The new stress values are compared with their allowables in Table 5.2-2.

5.2.8 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1968 Edition with Winter 1970 Addenda, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1977 Edition with Winter 1977 Addenda, The American Society of Mechanical Engineers, New York, NY.

3. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1967*, 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

Table 5.2-1
IP3 – SPU
Summary of Critical Reactor Internal Components Fatigue Usage Factors

Component	Cumulative Fatigue Usage Factor (U)
Lower Core Plate	[ ]a,c,e
Upper Core Plate	
Lower Support Columns	
Instrumentation Columns	
Core-Barrel-to-Lower-Support-Plate Junction	
Thermal Shield	
Top Hat Structure	

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.2-2

Maximum Stresses for BMI Tubes

Equation No.	Stress (psi)	Allowable Stress (psi)
		a,c,e
8	[	]
9		
10		
11		
9-Faulted		

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.3 Control Rod Drive Mechanisms

5.3.1 Introduction

This section addresses the ASME Code of Record structural considerations for the pressure boundary components of the Westinghouse full-length L-106 control rod drive mechanisms (CRDMs). The CRDMs were evaluated for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions.

5.3.2 Input Parameters and Assumptions

The Model L-106 CRDMs were originally designed and analyzed to meet the ASME Code 1965 Edition through the Summer 1966 Addenda or later (Reference 1). The Nuclear Steam Supply System (NSSS) design parameters for the IP3 SPU are provided in Table 2.1-2 of this report and the NSSS design transients are discussed in Section 3.1, also of this report. The seismic loading has not been changed for the IP3 SPU.

The IP3 CRDMs operate with a T_{hot} upper head condition, defined by the vessel outlet reactor coolant temperature of the SPU parameters, and must be analyzed for the NSSS design transients defined for the hot leg. The differences associated with the uprating requirements are discussed in subsection 5.3.3 of this report.

5.3.3 Description of Analysis

5.3.3.1 Operating Pressure and Temperature

The Reactor Coolant System (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°F, which is less than the 650.0°F temperature used in the original analysis of record. Since none of the temperatures exceeds the previously analyzed temperature, and the pressure does not change, the SPU parameters are bounded by the current analyses of record.

Table 5.3-1 summarizes the hot leg parameters. From Table 5.3-1, the SPU conditions provide an RCS T_{hot} of 580.3° to 603.0°F. Therefore, the original 650.0°F range bounds the range of T_{hot} for the SPU.

5.3.3.2 Transient Discussion

The only hot leg transient that has been modified to become more severe for the IP3 SPU is the loss-of-flow transient. For the loss-of-flow transient, the change in T_{hot} temperature for the high-temperature operating condition becomes -123°F. For the original design transient, the controlling temperature change for this transient was -92.6°F. Evaluations were performed to address the T_{hot} and pressure variations for this loss-of-flow transient. Also, more severe pressure variations for IP3 SPU occur for step-load rejection and reactor trip from full power. These were also evaluated as part of SPU.

Concerning the hydrotest at 2500 psi, the IP3 SPU implies a number of transient occurrences of 200 instead of 5, as previously required by the original equipment specification. These 200 occurrences of hydrotest were evaluated as part of the SPU and shown to be acceptable.

The results of these evaluations are addressed in subsection 5.3.5 for the IP3 SPU.

5.3.4 Acceptance Criteria

The acceptance criteria for the ASME Code structural analysis of the CRDM pressure boundary are that the analyzed stresses do not exceed the stress allowables of the ASME Code and that the cumulative usage factors from the Code fatigue analysis remain less than 1.0.

For the IP3 SPU, the stresses and the cumulative usage factors (CUFs) calculated for the CRDMs for the IP3 SPU remain acceptable.

5.3.5 Results

A summary of the results of the evaluation performed for the IP3 SPU is presented in Tables 5.3-2 and 5.3-3. The highest recalculated stresses, as compared to the associated allowables, are presented in Table 5.3-2 for the upper, middle, and lower joints of the CRDM pressure boundary. The CUFs that were recalculated for the IP3 SPU are given in Table 5.3-3. It is noted that the highest CUF, [ ]^{a,c} was calculated for the IP3 SPU at the upper joint canopy. For the original design calculation, a higher fatigue usage factor [ ]^{a,c} was calculated at the upper joint canopy in a conservative manner where the applied transients were grouped for analysis and the allowable number of cycles considered for each group was based on the most severe transient in the group.

5.3.6 Conclusions

The IP3 SPU Performance Capability Working Group (PCWG) parameters and NSSS design transients have been shown to be bounded by the parameters and transients considered for the original design analysis. The CRDMs are acceptable from a structural standpoint. The CRDM pressure boundary parts still satisfy the ASME Code of record. Therefore, the evaluation results for the SPU are consistent with, and continue to comply with, the current licensing basis/acceptance requirements for IP3.

References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition through Summer 1966 Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.3-1 PCWG Conditions Used to Bracket All Operating Conditions for IP3 SPU				
	3068-MWt Analysis		3216-MWt SPU	
Parameter	High T_{avg}	Low T_{avg}	High T_{avg}	Low T_{avg}
T_{hot}	600.8°F	600.8°F	603.0°F	580.3°F

Table 5.3-2 Highest Stresses, Compared to Allowables, for CRDM Joints, Applicable for IP3 SPU		
	Normal and Upset Condition Stresses (psi)	
*CRDM Joint and Component	Value Applicable for the SPU	Allowable Value
Upper Joint Canopy	[ ]a,c	48,300
Middle Joint Canopy		45,900
Lower Joint Canopy*		45,900
Capped Latch Housing (CLH) Short Cap		52,200

Bracketed [ ]^{a,c} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

* The 3 S_m allowable (45,900 psi) is exceeded by [ ]^{a,c} psi. This is insignificant and therefore considered acceptable.

Table 5.3-3 CUFs for CRDM Joints, Applicable for IP3 SPU		
CRDM Joint and Component	Cumulative Usage Factor	
	Value Applicable for the SPU	Allowable Value
Upper Joint Canopy	[ ]a,c	1.00
Middle Joint Canopy		1.00
Lower Joint Canopy		1.00
CLH Short Cap		1.00

Bracketed [ ]a,c information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.4 Reactor Coolant Loop Piping and Supports

5.4.1 RCL Piping

5.4.1.1 Introduction

The parameters associated with the Indian Point Unit 3 (IP3) stretch power uprate (SPU) were evaluated and analyzed to determine the effects on the analysis of WCAP-8228, Revision 1, (Reference 1) of the reactor coolant loop (RCL) analysis for the following components:

- RCL piping stresses and displacements
- Primary equipment nozzle loads
- Pressurizer surge line piping stresses and displacements including the effects of thermal stratification
- RCL branch nozzle loads
- Class 1 and 2 auxiliary piping systems

5.4.1.2 Inputs

The following four basic sets of input parameters were considered in the evaluation:

- Nuclear Steam Supply System (NSSS) design parameters (Table 2.1-2 of Section 2)
- NSSS design transients (Section 3 of this report)
- Loss-of-coolant accident (LOCA) hydraulic forcing functions loads (Section 6.7 of this document) and associated reactor pressure vessel (RPV) motions (Section 5.2 of this document)
- Secondary side pressure effects (Table 2.1-2 of Section 2)

The parameters associated with the SPU were reviewed to determine the effects on the existing RCL piping and the subsequent effects on the RCL branch nozzles and the Class 1 and 2 auxiliary lines attached to the RCL. The conclusions of this review are summarized later in subsection 5.4.1.6.

NSSS Design Parameters

The NSSS design parameters (see Table 2.1-2 of this report) were used in the thermal analysis of the RCL and the pressurizer surge line. The RCL was evaluated for two temperature conditions—one for the lower-bound temperature condition (Cases 1 and 2), and the second for the upper-bound temperature condition (Cases 3 and 4) as identified in Table 2.1-2.

NSSS Design Transients

The effect on design transients due to the changes in full-power operating temperatures for the SPU is addressed in Section 3 of this report. WCAP-8228 (Reference 1) specifies the design criteria for the RCL piping as *USAS B31.1 Power Piping Code*, 1967 Edition (Reference 2), which does not require fatigue analysis for the RCL.

For the pressurizer surge line, the effect of the design transients is controlled by the ΔT between the pressurizer temperature and the hot leg temperature. It has been shown that the temperatures and the design transients affected by the SPU have an insignificant effect on the pressurizer surge line analysis, including the effects of thermal stratification. However, this effect is also evaluated.

LOCA Hydraulic Forcing Functions Loads and Associated RPV Motions

The effect on the LOCA hydraulic forcing functions (HFFs) due to the SPU is addressed in Section 6.7 of this report. Leak-before-break (LBB) is applicable for the RCL main loop piping (see subsection 5.4.2). Based on the application of LBB, the RCL was evaluated for LOCA using HFFs generated for the SPU, based on breaks at the 14-inch surge line nozzle and at the 14-inch residual heat removal (RHR) line nozzle on the hot leg, and at the 10-inch accumulator line nozzle on the cold leg. RPV motions corresponding to the surge line break, RHR line break, and accumulator line break were also included.

Secondary Side Pressure Effects

The RCL was evaluated for secondary side breaks at the main steam line and feedwater line terminal end nozzle locations at the steam generator. The feedwater line break (FWLB) and the main steam line break (MSLB) evaluation for the SPU is performed based on the secondary side pressure in the NSSS design parameters (Table 2.1-2 of Section 2).

5.4.1.3 Analysis Methods

The system analysis of the RCL piping was performed using the methods in WCAP-8228 (Reference 1), using the computer program WESTDYN for deadweight, thermal expansion, LOCA and pipe break cases. The seismic analysis was performed using the WECAN computer code.

5.4.1.4 Acceptance Criteria

The acceptance criteria for the IP3 RCL Piping System as indicated in the *Indian Point Nuclear Generating Unit No. 3 Updated Final Safety Analysis Report (UFSAR)*, Table 1.4-1 and Section 10.2.1 (Reference 3) are based upon the *ANSI Code for Pressure Piping, Power Piping USAS B31.1*, 1955 Edition (Reference 4). For the stress analysis evaluation performed for the SPU, the acceptance criteria are based on the requirements established in *ANSI Code for Pressure Piping, Power Piping USAS B31.1*, 1967 (Reference 2), as specified in WCAP-8228 (Reference 1) in which the steam generator snubber elimination calculation was performed.

The acceptance criteria for the pressurizer surge line thermal stratification analysis are those in the *American Society of Mechanical Engineers (ASME) Boiler & Pressure Vessel (B&PV) Code* Section III, Subsection NB, 1986 Edition (Reference 5), as specified in WCAP-12937 (Reference 6).

The piping stress criteria for the RCL piping are the code-allowable stress values presented in Tables 5.4-1, 5.4-2, and 5.4-3.

5.4.1.5 Analysis and Results

The deadweight analysis for the SPU considered the weight of the RCL piping and the primary equipment water weight. Since there are no changes in the weight of the system, the deadweight analysis is not revised for the SPU. The results in the analysis of WCAP-8228 (Reference 1) remain applicable for the deadweight analysis.

The thermal analysis considered the range of operating temperatures for 100-percent power as defined by the SPU NSSS design parameters identified in Table 2.1-2 of this report. The temperatures used in the thermal analysis in WCAP-8228 (Reference 1) are shown to remain applicable to the corresponding temperature ranges for the SPU. Therefore, the thermal analysis results in WCAP-8228 (Reference 1) are shown to remain applicable for the SPU.

The seismic analysis performed in WCAP-8228 (Reference 1) has been shown to remain applicable for the SPU.

The LOCA analysis for the RCL is performed using the time-history hydraulic forces distributed throughout the RCL system, including the effects of the SPU-associated RPV motion. The analysis is performed for the breaks at the auxiliary nozzles for the 14-inch RHR line on the hot leg, the 14-inch surge line nozzle on the hot leg, and the 10-inch accumulator line on the cold leg. IP3 has been licensed for LBB on the main RCL piping. The LOCA analysis considered multiple cases based on the various primary equipment support activity cases and accounted for the range of operating temperatures as defined by the SPU NSSS design parameters.

Secondary side breaks at the main steam line and feedwater line terminal end nozzle locations at the steam generator are included in the analyses. The feedwater nozzle break analysis conservatively performed in WCAP-8228 (Reference 1) is shown to remain applicable for the SPU. The main steamline break (MSLB) analysis is performed using the secondary side pressure from the SPU NSSS design parameters.

The maximum RCL piping stress results for the RCL piping and the corresponding code-allowable stress values are presented in Tables 5.4-1, 5.4-2, and 5.4-3. The stresses were combined in accordance with the methods specified in the criteria in subsection 5.4.1.4. As per WCAP-8228 (Reference 1), the following stresses from the load combinations are required for the normal, upset, faulted, and thermal expansion conditions:

- Normal condition = pressure + deadweight
- Upset condition = pressure + deadweight +OBE
- Faulted 1 condition = pressure + deadweight + DBE
- Faulted 2 condition = pressure + deadweight + DBE + pipe rupture
- Thermal expansion condition = normal thermal

As can be seen in Tables 5.4-1 through 5.4-3, the RCL piping stresses are within the allowable limits and meet the acceptance criteria (Reference 2) and are acceptable for the SPU.

The primary equipment nozzle loads were compared to the allowables and to previously qualified nozzle loads evaluated for WCAP-8228 (Reference 1) as applicable and are shown to meet the criteria and to be acceptable for the SPU and have no adverse effect on the results.

The SPU effect on the RCL piping displacements at the RCL branch nozzles and corresponding Class 1 and Class 2 auxiliary piping systems was evaluated. These evaluations considered the SPU parameters, SPU LOCA HFFs, and the NSSS fluid system performance evaluation in Section 4 of this report. These evaluations included the Reactor Coolant System (RCS), Primary Sampling System (PSS), Chemical and Volume Control System (CVCS), Residual Heat Removal System (RHRS), Safety Injection System (SIS), Component Cooling Water System

(CCWS), and the Containment Spray System (CSS). The SPU effect on RCL piping displacements at branch nozzles had a negligible effect on the RCL branch nozzle loads and on the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL.

Based on the discussion in subsection 5.4.1.2 for the evaluation of the NSSS design parameters and the NSSS design transients for the SPU, the current design basis pressurizer surge line analysis results including the effects of thermal stratification in WCAP-12937 (Reference 6), are applicable and meet the acceptance criteria for the SPU. Therefore, the SPU will have no adverse effect on either the thermal stratification or the fatigue analysis for the pressurizer surge line, and the limiting transients and the pressurizer surge line evaluation in WCAP-12937 (Reference 6) remain valid.

5.4.1.6 Conclusions

The RCL piping stress results in Tables 5.4-1, 5.4-2, and 5.4-3 demonstrate that the RCL piping stresses meet the required stress criteria under the SPU.

The primary equipment nozzle loads are shown to meet the criteria and are acceptable for the SPU and have no adverse effect on the results.

RCL piping displacements at branch nozzles due to the SPU has no adverse effect on either the RCL branch nozzle loads or the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL. Therefore, these nozzles and piping systems meet the acceptance criteria and are acceptable.

Additionally, the current design basis analysis results for the pressurizer surge line as documented in WCAP-12937 (Reference 6), including the effects of thermal stratification, are still applicable, acceptable, and meet the acceptance criteria and remain valid for the SPU.

Therefore, based on the evaluations performed on the RCL piping system for the SPU, the RCL piping system is adequate and acceptable, and meets all the acceptance criteria.

5.4.2 Application of LBB Methodology

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. This section 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 SPU.

5.4.2.1 Introduction

LBB analyses were performed for the IP3 primary loop piping in 1984 and 1997. The results of the 1984 LBB analyses were documented in *Fracture Proof Design Corporation Report 80-121*, Revision 0 (Reference 7), and approved by the NRC (Reference 8). Analyses performed in 1997 to support the Steam Generator Snubbers Deactivation Program and the results of the LBB analyses were documented in Appendix A of the WCAP-8228 (Reference 1).

To demonstrate the elimination of RCS primary loop pipe breaks, the following objectives had to be achieved:

- Demonstrate that margin exists between the "critical" crack size and a postulated crack that yields a detectable leak rate.

- Demonstrate that there is sufficient margin between the leakage through a postulated crack and the leak detection capability.

- Demonstrate margin on the applied load.

- Demonstrate that fatigue crack growth is negligible.

These objectives were met and are documented in the *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1).

To support the IP3 SPU, the current LBB analyses were updated to address SPU conditions. The SPU evaluation and results are addressed below.

5.4.2.2 Input Parameters and Assumptions

The loadings, operating pressure, and temperature parameters for the SPU were used in the evaluation.

The parameters, which are important in the evaluation, are the piping forces, moments, normal operating temperature, and normal operating pressure. These parameters were used in the evaluation. For normal operating temperature and normal operating pressure at the SPU conditions, see Section 2 of this report.

5.4.2.3 Description of Analyses and Evaluations

The recommendations and criteria proposed for LBB evaluation in *Standard Review Plan* (SRP) 3.6.3 (Reference 9) are used in this evaluation. The primary loop piping deadweight, normal thermal expansion, safe shutdown earthquake (SSE), and pressure loads due to the SPU have been used. The normal operating temperature and pressure due to the SPU conditions were used in the evaluation. The evaluation showed that all the LBB-recommended margins were satisfied for the SPU conditions. The margins from SRP 3.6.3 (Reference 9) are also described below.

5.4.2.4 Acceptance Criteria and Results

The LBB acceptance criteria is based on the SRP 3.6.3 (Reference 9). The recommended margins are as follows:

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

The evaluation results showed the following at all the critical locations:

Leak Rate – There is a margin of 10 between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gpm.

Flaw Size – There is a margin of 2 or more between the critical flaw and the flaw having a leak rate of 10 gpm (the leakage flaw).

Loads – There is a margin of 1 on loads.

The evaluation results show that the LBB conclusions provided in the *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1) for IP3 remain unchanged for SPU conditions.

5.4.2.5 Conclusions

The LBB acceptance criteria are satisfied for the IP3 primary loop piping at the SPU conditions. All the recommended margins are satisfied and the conclusions shown in *Fracture Proof Design Corporation Report* (Reference 7) and Appendix A of the WCAP-8228 (Reference 1) remain valid. It is, therefore, concluded that the dynamic effects of RCS primary loop pipe breaks need not be considered in the structural design basis of IP3 at the SPU conditions.

5.4.3 RCS Equipment Supports

5.4.3.1 Introduction

This report documents the acceptability of the equipment supports for the SPU conditions. The parameters associated with the SPU were reviewed to determine the effects of the SPU conditions on the existing design basis analysis for the RCS equipment supports (RCSES). The following loads were considered in the analysis:

- Piping loads on RCSES
  - Deadweight
  - Thermal
  - Pressure
  - Operating basis earthquake (OBE) and design basis earthquake (DBE)
  - Pipe break (main steam and feedwater)
  - LOCA (pressurizer surge line, RHR, 45-degree, and 90-degree accumulator)
- Loads due to attachments to RCSES
  - Pipe supports
  - Whip restraints
- Pipe whip and jet impingement loads on RCSES
  - From 10-inch lines and larger

Note that per subsection 5.4.1.5, "The SPU effect on RCL piping displacements at branch nozzles had a negligible effect on the RCL branch nozzle loads and on the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL." Therefore, support reconciliations are not required.

5.4.3.2 Inputs

The following sets of inputs were used in the evaluation:

- RCSES as-built drawings and embedment allowables
- Support pipe whip and jet impingement loads
- Support attachment locations and loads
- RCL piping loads
- Reactor vessel loads

The IP3 RCL was re-analyzed for postulated LOCA to incorporate the SPU power uprate conditions. The RCL piping analysis calculated revised loads from the piping to the steam generator and RCP supports. The reactor vessel analysis calculated revised loads for the reactor vessel support reconciliation.

5.4.3.3 Analysis Methods

The equipment supports were analyzed by developing detailed structural computer models of the steam generator and reactor coolant pump (RCP) support frames, then loading the frame with the various loads determined in the RCL piping analysis. Additional loads corresponding to auxiliary line pipe whip, pipe whip restraint attachments, and pipe supports were also applied to the support frames. GTSTRUDL Version 26 NT was used for the structural modeling. The GTSTRUDL code evaluation option was used to qualify the standard AISC shapes used in the support frames per the acceptance criteria discussed in subsection 5.4.3.4. For the non-standard members, stresses were obtained from GTSTRUDL and calculations were then performed to satisfy the code interaction equations. The support frame embedment reactions calculated within GTSTRUDL were compared with the allowable embedment loads. Miscellaneous members such as tie rods were qualified with the use of separate calculations.

The reactor vessel supports were qualified by comparing the maximum LOCA faulted loads on the supports with the allowable loads on the support shoe developed per scale model tests. The LOCA loads on the reactor vessel support envelope loads due to the other pipe breaks, MSLB, and feedwater break, since the secondary side breaks do not cause the large primary side pressure waves associated with a primary side break.

The normal, seismic, feedwater break, and mainsteam break loads on the support structures were not affected by the SPU, therefore, the SPU support evaluations focused only on the faulted conditions containing the postulated LOCA cases. The normal, upset, and faulted RCS equipment support evaluations for the mainsteam and feedwater breaks previously performed for the steam generator snubber elimination analyses completed in 1997 were not affected by the SPU and, therefore, were not redone.

The loads considered in the support evaluations are as follows:

- Deadweight — Loads due to deadweight of equipment, attached piping, insulation, and contained fluids
- Thermal — Load on the supports due to constrained thermal expansion of the RCL
- Pressure — Loads on the supports due to system pressure of the RCL

- OBE — Seismic loads due to the OBE
- DBE — Seismic loads due to the DBE
- Main steamline — Loads due to a break at the steam generator main steamline nozzle (MSLB)
- Feedwater line — Loads due to a break at the steam generator main feedwater line nozzle (FLB)
- LOCA — Loads due to a break in any one of several RCL nozzles, that is, surge line nozzle, RHR line nozzle, or accumulator line nozzle

The LOCA loads on the support structures were combined with the DBE loads by the square root of the sum of the squares (SRSS) method, then added to the deadweight, pressure, and thermal loads to form the faulted loading combinations considered in the GTSTRUDL analyses.

Normal, seismic, and pipe break loads were combined based on the probability of occurrence and evaluated to stress levels that were increased for low probability events. The load combinations identified in Table 5.4-4 are based on Table 16.1-2 of the UFSAR (Reference 3).

5.4.3.4 Acceptance Criteria

The acceptance criteria for the IP3 RCSES are based upon Table 16.1-2 in the UFSAR (Reference 3), in combination with the criteria discussed below.

Steam Generator and RCP Frames

Load Cases 1, 2, and 3 were previously qualified as part of the Steam Generator Snubber Elimination Program and are not impacted as part of the SPU. Load case 4 is enveloped by load Case 5.

For load Cases 4 and 5 the criteria is that "Deflections and stresses of supports limited to maintain supported equipment within their stress limits." This correlates to limiting the deflection of the supports such that additional stresses do not occur in the supported piping/equipment. Acceptable means of satisfying the above criteria are to use the faulted increase factors provided in Appendix F of the 1974 *Boiler & Pressure Vessel* Section III Code for Supports, that is, F-1370(a) and F-1370(c) (Reference 10). These rules state that the increase factor for faulted-condition loads can be increased above the Level A (AISC allowables) by:

- Increase Factor (IF) = minimum 1.2 x (S_y / F_t) and 0.7 x (S_u / F_t)
  Since F_t = 0.6 S_y for the frame members being considered,

- IF = minimum 2 and $(0.7 \times S_u) / (0.6 \times S_y)$
- Section F-1370(c) states that loads shall not exceed 2/3 of the critical buckling load

Steam Generator and RCP Tie Rods

The steam generator and RCP tie rods are tension members. As such, the allowable loads were based on the lesser of the turnbuckle rated load multiplied times 1.33, the tensile stress in the tie rods, and the bearing stress under the nuts. The turnbuckle rated load (which is 20 percent of the turnbuckle ultimate capacity) multiplied times 1.33 is the controlling allowable load for the tie rods.

Concrete Embedments

The calculated loads on the embedments were shown to be enveloped by the embedment allowable loads (see Table 5.4-5) from the original design.

RCP and Steam Generator Holddown Bolts

Each pump foot is restrained by a 4-inch diameter A490 bolt. The allowable tension stress, allowable shear stress and shear tension interaction defined in ASME Code Case 1644-6 (Reference 11) and Appendix F (Reference 10) was used to evaluate the A490 bolts since the AISC Sixth Edition (Reference 12) does not specify allowable stresses for A490 bolts.

The steam generator feet are connected to a pad with a 2.75-inch diameter ASTM A540 Class 1 pin and four 3/4-inch diameter A490 bolts. The pad is then connected the steam generator frame columns with four 2-inch diameter ASTM A540 Class 2 bolts.

This connection was evaluated by calculations to satisfy the allowable tension stresses and the allowable shear stresses per Code Case 1644 and Appendix F in the bolts and pins.

RPV Supports

The reactor vessel support evaluations were based on WCAP-9117 (Reference 13). This report documents scale model tests that were used to determine the reactor vessel support shoe horizontal capacity. The support shoe governs the overall support horizontal capacity.

5.4.3.5 Analysis and Results

The loads on the steam generator, RCP, and RPV supports meet the acceptance criteria provided in subsection 5.4.3.4 of this report.

As noted previously in subsections 5.4.1.5 and 5.4.3.1, the effect on RCL piping displacements at branch nozzles due to the SPU has no subsequent effect on either the RCL branch nozzle loads or the Class 1 and Class 2 auxiliary piping systems that are attached to the RCL (as applicable). Therefore, the supports for the auxiliary piping systems are not affected by the SPU. The previous analyses for these supports apply for the SPU.

A summary of the results is provided in Table 5.4-6.

5.4.4 References

1. WCAP-8228, Vol. 1, *Structural Evaluation of Reactor Coolant Loop/Support System For Indian Point Nuclear Generating Station Unit No. 3*, Rev. 1, April 1997

2. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1967*, 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1.0 – 1955*, 1955 Edition, The American Society of Mechanical Engineers, New York, NY.

5. *American Society of Mechanical Engineers Boiler & Pressure Vessel Code*, Section III, Subsection NB, 1986 Edition, The American Society of Mechanical Engineers, New York, NY.

6. WCAP-12937, *Structural Evaluation of Indian Point Units 2 and 3 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification*, May 1991.

7. *Fracture Proof Design Corporation Report 80-121, Summary of the Tearing Stability Analysis of the Indian Point 3 Primary Coolant System*, Rev. 0, May 4 1984.

8. NRC Docket # 50-286, Letter from Steven A. Varga PWR Project Directorate No. 3, Division of PWR Licensing-A of the NRC to Mr. John C. Brons, Senior Vice President Power Authority of the State of New York, March 10, 1986.

9. *Standard Review Plan*, Public Comment Solicited, 3.6.3, "Leak-Before-Break Evaluation Procedures," Federal Register/Vol. 52, No. 167/Friday, August 28, 1987/Notices, pp. 32626-32633.

10. *ASME Boiler & Pressure Vessel Code,* Section III, Appendix F, 1974 Edition, The American Society of Mechanical Engineers, New York, NY.

11. *ASME Boiler & Pressure Vessel Code*, Code Case 1644-6, The American Society of Mechanical Engineers, New York, NY.

12. *American Institute of Steel Construction (AISC) Specification for Design, Fabrication & Erection of Structural Steel for Buildings*, 1963 Edition.

13. WCAP-9117, *Analysis of Reactor Coolant System for Postulated Loss-of-Coolant Accident: Indian Point 3 Nuclear Power Plant*, June 1977.

Table 5.4-1

RCL Piping Stress Analysis Summary for Loops 31/34 – SPU

Stress Combination	Hot Leg		Crossover Leg		Cold Leg	
	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi
Normal Condition (pressure + deadweight)	6.985 (1) 5.296(2)	17.050(1) 14.950(2)	6.821(1) 5.403(2)	17.050(1) 14.950(2)	6.850(1) 5.429(2)	17.050(1) 14.950(2)
Allowable Stress Limit(5)	(1.0 S)		(1.0 S)		(1.0 S)	
Upset Condition (pressure+deadweight + OBE)	13.137 (1)	20.460 (1)	10.755 (1)	20.460 (1)	9.693 (1)	20.460 (1)
Allowable Stress Limit(5)	(1.2 S)		(1.2 S)		(1.2 S)	
Faulted 1 Condition (pressure+deadweight+DBE)	13.137 (1)	20.460 (1)	10.755 (1)	20.460 (1)	9.693 (1)	20.460 (1)
Allowable Stress Limit(5)	(1.2 S)		(1.2 S)		(1.2 S)	
Thermal Expansion Condition (normal thermal)	17.350 (1)	27.700 (1)	6.240 (1)	27.700 (1)	3.850 (1)	27.700 (1)
Allowable Stress Limit(5)	(1.25 x S_c + 0.25 x S_h)		(1.25 x S_c + 0.25 x S_h)		(1.25 x S_c + 0.25 x S_h)	

Note:

1. These are the maximum stresses and allowable corresponding to piping material.
2. These are the maximum stresses and allowable corresponding to elbow material.
3. S = Allowable stress in material at the operating temperature.
4. S_c = Allowable Stress of material at ambient temperature (70°F).
5. S_h = Allowable Stress of material at maximum hot temperature (650°F).

   Per References 1 and 2.

Table 5.4-2 RCL Piping Stress Analysis Summary for Loops 32/33 – SPU						
Stress Combination	Hot Leg		Crossover Leg		Cold Leg	
	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi	Maximum ksi	Allowable ksi
Normal Condition (pressure + deadweight)	6.985 [1] 5.296 [2]	17.050 [1] 14.950 [2]	6.821 [1] 5.403 [2]	17.050 [1] 14.950 [2]	6.750 [1] 5.329 [2]	17.050 [1] 14.950 [2]
Allowable Stress Limit [5]	(1.0 S)		(1.0 S)		(1.0 S)	
Upset Condition (pressure+deadweight+OBE)	12.864 [1]	20.460 [1]	10.458 [1]	20.460 [1]	9.300 [1]	20.460 [1]
Allowable Stress Limit [5]	(1.2 S)		(1.2 S)		(1.2 S)	
Faulted 1 Condition (pressure+deadweight+DBE)	12.864 [1]	20.460 [1]	10.458 [1]	20.460 [1]	9.300 [1]	20.460 [1]
Allowable Stress Limit [5]	(1.2 S)		(1.2 S)		(1.2 S)	
Thermal Expansion Condition (normal thermal)	17.150	27.700	7.150	27.700	7.350	27.700
Allowable Stress Limit [5]	$(1.25 \times S_c + 0.25 \times S_h)$		$(1.25 \times S_c + 0.25 \times S_h)$		$(1.25 \times S_c + 0.25 \times S_h)$	

Note:

1. These are the maximum stresses and allowable corresponding to piping material
2. These are the maximum stresses and allowable corresponding to elbow material.
3. S = Allowable stress in material at the operating temperature.
4. S_c = Allowable Stress of material at ambient temperature (70° F).
5. S_h = Allowable Stress of material at maximum hot temperature (650° F).
   Per References 1 and 2.

Table 5.4-3

Faulted 2 Condition Maximum Piping Stress
Pressure + Deadweight + DBE + Pipe Rupture - Combination Case

	Piping Stress (ksi)						Stress Ratio				
	SI	S_Y	S_a Max.	S_a Min.	S_τ	S_H	SI/S_Y	S_a Max. / S_Y	S_a Min. / S_Y	S_τ / S_Y	S_H / S_Y
Steam Generator Inlet Elbow Critical Location	48.75	19.0	3.58	-3.58	1.89	11.45	2.6	0.20	-0.20	0.10	0.60

Note:

1. SI = Stress Intensity (KSI).
2. S_Y = Yield Strength (KSI).
3. S_a = Axial Stress (KSI).
4. S_τ = Shear Stress (KSI).
5. S_H = Hoop Stress (KSI).

Table 5.4-4

Support Load Combinations and Allowable Stress

Load Combinations	Allowable Stress
1. Normal (deadweight + thermal + pressure + pipe support attachments)	AISC working stresses or applicable factored load design values
2. Upset (normal + OBE)	AISC 1-1/3 working stresses or applicable factored load design values
3. Faulted (normal + DBE)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits
4. Faulted (normal + pipe break + pipe whip)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits
5. Faulted (normal + DBE + pipe break + pipe whip)	Deflections and stresses of supports limited to maintain supported equipment within their stress limits

Table 5.4-5

Allowable Concrete Embedment Loads

Support	Direction	Allowable Load (kips)
RPV	Downward	5136
	Horizontal	6283
Steam Generator Upper Support Guides	Perpendicular to hot leg	756
	Parallel to hot leg	635
Steam Generator Columns	Tension	827
	Shear	847
RCP Columns	Tension	1072
Tie Rods	Minimum tension(1)	1050

Note:

1. Only allowables for two tie rods attached outside the primary shield wall are provided. For all other tie rods, the tie rods extend through the primary shield wall and the allowable would be much greater.

Table 5.4-6 RCSES Stress Analysis Summary – SPU (interaction ratios are for load Case 5, Normal + SRSS [DBE, LOCA])			
Support		Maximum Interaction Ratio	Comment
1. Steam Generator Frame Structure		0.95	Axial tension plus bending on pipe stub columns(1)
2. RCP Frame Structure		0.67	Axial compression plus bending on reinforced column(2)
3. Steam Generator/RCP Tie Rods		0.32	Based on 1.33 x turnbuckle rated working load(3)
4. Equipment Pad Holddown Bolts	Steam Generator	0.85	Shear on 2.75-inch pin and tension in 0.75-inch bolts(4)
	RCP	0.59	Tension, shear on 4-inch bolt(5)
5. Embedments	Steam Generator	0.56	Uplift at column bases(6)
	RCP	0.67	Uplift at column bases(7)

Note:

The SPU did not affect the FLB and MSLB qualifications performed for the Snubber Elimination Program, and those break cases are not included in this table.

1. Calculated axial stress = 20.6 ksi Allowable axial stress = 41.3 ksi
   Calculated bending stress = 18.7 ksi Allowable bending stress = 41.3 ksi
2. Calculated axial stress = 12.2 ksi Allowable axial stress = 23 ksi
   Calculated bending stress = 4.9 ksi Allowable bending stress = 34.4 ksi
3. Calculated load = 98 kips Allowable load = 311 kips
4. Calculated shoe uplift = 835 kips Allowable shoe uplift = 980 kips
5. Calculated tension load = 689 kips Allowable tension load = 1166 kips
   Calculated shear load = 120 kips Allowable shear load = 546 kips
6. Calculated uplift = 460 kips Allowable uplift = 827 kips
7. Calculated uplift = 716 kips Allowable uplift = 1072 kips

5.5 Reactor Coolant Pumps and Motors

The reactor coolant pumps (RCPs) at Indian Point Unit 3 (IP3) were evaluated for the stretch power uprate (SPU) in two separate areas: the structural adequacy of the pumps (subsection 5.5.1 of this report), and the acceptability of the RCP motors (subsection 5.5.2).

5.5.1 RCPs Structural Integrity

5.5.1.1 Introduction

This section addresses the ASME Code structural considerations for the pressure boundary components of the Westinghouse Model 93 RCPs. The RCP is not a Code vessel, but the IP3 RCP equipment specification requires that the design, analysis, materials, welding, inspection, and testing of the pumps meet the requirements of the ASME Code, Section III. The 1965 Edition, and later addenda and editions, are used as a basis for the design (Reference 1).

The evaluation of the RCPs for the SPU considered the SPU parameters (see Section 2 of this report), and the Nuclear Steam Supply System (NSSS) design transients (see Section 3.1 of this report), which assumed a core power of 3216 MWt.

The evaluation of the RCPs for the SPU compared the operating temperatures and pressures defined in the SPU NSSS parameters to the pressures and temperatures considered in previous analyses of the RCPs. In addition, the NSSS design transients for the SPU were compared to the transients considered in previous evaluations. For the inputs that were not enveloped by the previous analyzed parameters, stress levels were ratioed to account for the changes and the stresses were verified to remain below the allowable values.

5.5.1.2 Input Parameters and Assumptions

The Model 93 RCPs were originally designed and analyzed to meet the RCP equipment specification and the ASME Code. Evaluations of the RCPs were performed in stress analyses prepared for the original design and for the 1.4-percent measurement uncertainty recapture (MUR).

The IP3 RCPs are installed in the Reactor Coolant System (RCS) cold leg, between the steam generator outlet and the reactor vessel inlet. The temperatures and pressures used as inputs to the RCP Code structural analysis are those defined for the reactor vessel inlet in the SPU NSSS parameters (Table 2.1-2). The RCPs have been evaluated for the NSSS design transients, as defined for the RCS cold leg by the equipment specification and updated by this SPU.

5.5.1.3 Description of Analysis

Operating Temperature and Pressure

The SPU parameters (see Section 2 of this report) were used to evaluate the acceptability of the RCPs. From the SPU parameters, there are no changes from the current reactor coolant pressure of 2250 psia for any of the SPU cases. The RCS cold-leg temperature (T_{cold}), defined by the vessel inlet (RCP outlet) temperature on the SPU NSSS parameters for the IP3 SPU, is a maximum of 541.5°F. The maximum SPU RCS T_{cold} is less than the equipment specification operating temperature of 555°F and is also less than the 1.4-percent MUR T_{cold} temperature of 542.2°F. Since none of the temperatures exceeds the previously considered temperatures, and the pressure does not change, the SPU parameters are bounded by those defined in the equipment specification and used as inputs to the 1.4-percent MUR evaluation.

Table 5.5-1 summarizes the cold-leg SPU NSSS temperatures. From Table 5.5-1, the originally specified operating temperature is 555°F and the present (1.4-percent MUR) RCS T_{cold} value is 542.2°F, compared to an RCS T_{cold} range of 517.3° to 541.5°F for the SPU. Since higher temperatures correspond to lower allowable stresses, a decrease in operating temperature is conservative. Therefore, the present operating temperature bounds the maximum RCS T_{cold} temperature for the SPU. Furthermore, both conditions are bounded by the originally specified operating temperature of 555°F.

Transient Discussion

The NSSS design transients have been recalculated for the IP3 SPU. The recalculated transients have some temperature and pressure changes that are different from the design transients given in the equipment specification. The transients defined for the 1.4-percent MUR were shown to be bounded by the original equipment specification transients.

The cold leg transients applicable to the RCP evaluation are shown on Table 5.5-2. Since there is some variation in the transients considered in the original analyses, the comparison of the revised transients to the analyzed transients is approached on the basis of the original stress analyses (see Table 5.5-3).

Main Flange Bolted Joint Stress Analysis

This analysis shows that the transients other than the heatup and cooldown transients do not affect the fatigue usage of the main flange bolted joint. The cumulative usage factor (CUF) for the main flange bolts thus remains as calculated. The highest stress in the bolts occurs for the loss-of-load transient, which had a maximum pressure increase of 500 psi in the original analysis. This maximum pressure increase has now increased to 525 psi, and thus an adjustment of the maximum stress levels is required. This increase is minor, and the stresses remain within the ASME Code allowable values. The values of these stresses are shown in Table 5.5-3.

Pump Casing Stress Analysis

The transients considered in this analysis differ from the ones that were originally specified for the IP3 RCPs, and in most cases they were more severe. The exception to this is the temperature range spanned by the heatup and cooldown transients. In the original analysis, the temperature range considered was 433°F, while the IP3 temperature range is 447°F. The maximum values of the stress intensity occurred at the suction nozzle area of the casing. Adjusting the calculated thermal stresses for this difference results in small increases in the primary-plus-secondary stress intensity and the maximum thermal-plus-pressure-plus mechanical stress intensity. The stress intensities remain less than the ASME Code allowable values. The values of these stress intensities are shown in Table 5.5-3.

Support Foot Analysis

The support foot is considered a structural member in the original analysis and is analyzed only for mechanical loads. There is no transient analysis.

Auxiliary Nozzles

The original auxiliary nozzle analysis was prepared specifically for IP3. This analysis addressed the seal injection, No.1 seal leak off, and No. 2 seal leak off nozzles, and the component cooling water inlet and outlet nozzles for the thermal barrier heat exchanger, the motor upper bearing oil cooler, and the motor lower bearing oil cooler. The analysis that was performed was based on the loads that were applied to the auxiliary nozzles, and the internal pressure within the auxiliary nozzles. No cold leg transients were considered in the analysis. Thus, there is no effect from changes to the cold leg transients.

5.5.1.4 Acceptance Criteria

The acceptance criteria for the ASME Code structural analysis of the RCP pressure boundary are that the analyzed stresses do not exceed the stress allowables of the ASME Code and that the CUFs from the Code fatigue analysis remain less than 1.0. This can be demonstrated by showing that the design inputs for the SPU are either unchanged or bounded by the design inputs used in previous analyses, which show that the RCPs meet the ASME structural integrity criteria. For those inputs that are not bounded by the inputs used in previous analyses, then adjusted stresses or usage factors are calculated and compared to the ASME Code allowables.

5.5.1.5 Results

The operating temperature and pressure discussion presented in subsection 5.5.1.3 showed that the operating temperatures and pressures are unchanged or bounded by those considered for previous analyses and evaluations, as shown in Table 5.5-1.

For the NSSS design transients, the original stress analyses and evaluations have been shown to be applicable to the current SPU conditions, with the exception of some stresses in the main flange bolts and in the casing that have been adjusted to incorporate the effects of revised design transients. The adjusted stresses continue to meet the ASME Code allowable values that were considered in the original analyses. The cumulative usage factors are not affected by the SPU and the RCPs remain within the ASME Code requirements. A summary of the peak stresses and cumulative usage factors is provided in Table 5.5-3.

5.5.1.6 Conclusions

The stresses and CUFs resulting from the SPU parameters and NSSS design transients have been shown to be bounded by the stresses and CUFs resulting from the parameters and transients considered in the original analyses and evaluations, or have been recalculated and shown to continue to be in compliance with the ASME Code allowable values. The RCPs are acceptable from a structural standpoint. The RCP pressure boundary parts still comply with the ASME Code originally specified or later editions. Therefore, the evaluation results of the SPU for the RCP structural evaluation are consistent with and continue to comply with the current licensing basis and acceptance requirements for IP3.

5.5.2 Reactor Coolant Pump Motors

5.5.2.1 Introduction

This section addresses the performance of the RCP motors. The RCP motors are evaluated for the IP3 SPU parameters and best-estimate flows, which assumed a core power of 3216 MWt.

5.5.2.2 Input Parameters and Assumptions

The input parameters considered in the evaluation of the RCP motors are the steam generator outlet temperatures and the best-estimate flows defined for the IP3 SPU. These parameters are considered for the IP3 Model 93 RCPs containing impeller serial numbers 320, 321, 323, and 1561, and for spare impeller serial number 322.

5.5.2.3 Description of Analysis

The steam generator outlet temperatures and best-estimate flows are considered in a hydraulic analysis using the operating characteristics of the IP3 RCPs. This hydraulic analysis calculates the power requirements for the impeller that operates at the highest cold power. For the IP3 SPU, the power requirements from this analysis for hot-loop and cold-loop operation were compared to the hot and cold nameplate ratings for the motors. The power requirements for the SPU were determined to be within the nameplate ratings of the motors. Therefore, the RCP motors are acceptable for the SPU.

The IP3 SPU evaluated the RCP motor loading in three areas:

- Continuous operation at hot-loop temperatures and flows
- Continuous operation at cold-loop temperatures and flows
- Thrust-bearing loading

5.5.2.4 Acceptance Criteria

For the IP3 SPU, the acceptance of the RCP motor loading is based on the hot and cold brake horsepower requirements being within the nameplate ratings of the motors. The motors have been shown by test and analysis to operate within the equipment specification limits at the nameplate ratings. Per design, motor operation is acceptable for any load up to the hot nameplate rating of 6000 horsepower (hp) and the cold loop nameplate rating of 7500 hp.

Per the original equipment specifications, the temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 120°F must be in accordance with the National Electric Manufacturers' Association (NEMA) Standard MG1-20.40-1963.

Per the equipment specifications, the motor is required to drive the pump for up to 50 hours (continuous) and 3000 hours maximum over the 40-year design life under cold-loop conditions.

The thrust-bearing loading used for the motor design is given in the equipment specifications. Performance of the thrust bearings in an RCP motor can be adversely affected by excessive or inadequate loading. The thrust-bearing loading for the revised conditions is compared to the design thrust-bearing loading to determine continued acceptability.

5.5.2.5 Results

The worst case loads for the RCP motors were calculated for the IP3 SPU operating conditions. The new worst-case hot-loop load under the revised operating conditions is 5969 hp. The new worst-case cold-loop load under the revised operating conditions is 7425 hp. These loadings are less than the motor nameplate ratings of 6000 hp for hot-loop operation and 7500 hp for cold-loop operation. Thus, the revised motor loadings are acceptable based on the loadings being within the nameplate ratings for the motors.

The evaluations of the RCP motors that are the basis of the IP3 SPU conclusions are described in the following paragraphs.

Continuous Operation at Hot-Loop Conditions

The worst-case hot-loop operating load for the SPU is 5969 hp, which is below the nameplate rating of the motor, 6000 hp. Since the loading is within the nameplate rating of the motor, it is acceptable without further calculations.

Continuous Operation at Cold-Loop Conditions

The worst-case cold-loop operating load of 7425 hp for the SPU is below the nameplate cold-loop rating of the motor, 7500 hp. Since the loading is within the cold nameplate rating of the motor, it is acceptable without further calculations.

Thrust-Bearing Loading

The thrust-bearing loadings for the IP3 SPU conditions indicate a reduction in the thrust-bearing load of 6024 lbs for hot-loop operation, and an increase of 2674 lbs for cold-loop operation. In comparison to the normal operating thrust-bearing load of 101,200 lbs, these changes are not considered significant and the thrust bearings are acceptable for the SPU loads.

Motor Ambient Temperature

The temperature rise of the motor while driving the pump continuously under hot-loop conditions with an ambient temperature of 130°F will continue to meet National Electric Manufacturers' Association (NEMA) Standard MG1-20.40-1963.

5.5.2.6 Conclusions

The RCP motors are evaluated in three areas for the IP3 SPU conditions, under loadings of 5969 HP for worst-case hot-loop operation and 7425 HP for worst-case cold-loop operation. Since the new RCP motor loads are within the nameplate ratings of the motors the motor, temperature rise for hot and cold operating conditions will be within the NEMA requirements and the first two areas meet requirements. In comparison to the normal operating thrust-bearing load of 101,200 lbs, the SPU changes are not considered significant and the thrust bearings remain acceptable for the SPU loads. Therefore, the RCP motors at IP3 are acceptable for operations at the SPU conditions.

5.5.3 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition with later Editions and Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.5-1 SPU NSSS Conditions Used to Bracket All Operating Conditions				
	Equipment Specification	Present (1.4-percent MUR Program)	SPU	
Parameter	Operating Temperature	Operating Temperature	High T_{avg}	Low T_{avg}
T_{cold} (vessel inlet)	555°F	542.2°F	541.5°F	517.3°F

Table 5.5-2 Cold Leg Thermal Transient Summary for RCP Evaluation for IP3 SPU(1)			
	Thermal Transient ΔT (°F)	Pressure Transient ΔP (psi)	Occurrences
Normal Condition			
Heatup/Cooldown	[		]a,c,e
Unit Loading/Unloading at 5% of Full Power			
Step Increase/Decrease of 10% Full Power			
Large Step-Load Decrease with Steam Dump			
Steady-State Fluctuations			
Upset Condition			
Loss of Load			
Partial Loss of Flow			
Reactor Trip from Full Power			

Notes:

1. The number of occurrences of the transients, and the pressure and temperature changes for heatup, cooldown, and the steady-state fluctuations, are taken from the RCP equipment specification. The other pressure and temperature changes are those defined for the SPU.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.5-3 RCP Stress and Fatigue Evaluation for IP3 SPU					
	Max Stress Intensity (psi)(1)			Cumulative Usage Factor	
RCP Component	Original Value	Recalculated Value	Allowable (psi)(1)	No Usage Factors Were Recalculated	ASME Code
Casing(2)	[			]a,c,e	1965
Main Flange Bolting				]	1965

Notes:

1. The ASME Code year used as the basis for the allowable stress is listed in the "ASME Code" column of this table.
2. The three values given are for primary general membrane stress intensity, primary membrane plus bending stress intensity, and primary plus secondary membrane plus bending stress intensity. The corresponding allowable stresses are equal to S_m, 1.5 S_m, and 3 S_m, where S_m is 16,700 psi.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.6 Steam Generators

Evaluations of the thermal-hydraulic performance, structural integrity, and mechanical hardware have been performed to address operation of the Indian Point Unit 3 (IP3) steam generators at stretch power uprate (SPU) conditions.

5.6.1 Thermal-Hydraulic Evaluation

The thermal-hydraulic evaluations of the IP3 Model 44F steam generators focused on the changes to secondary side operating characteristics at the proposed SPU conditions. The SPU design operating conditions considered are presented in Table 2.1-2 of this report. The evaluations discussed in this section were performed to confirm the acceptability of the steam generator secondary side parameters. Four cases were analyzed at the 3230-MWt Nuclear Steam Supply System (NSSS) power corresponding to the 3216-MWt core power conditions: two Reactor Coolant System (RCS) primary average temperatures (T_{avg}), 549.0° and 572.0°F, and two steam generator tube plugging (SGTP) levels, 0 and 10 percent.

The four cases are distinguished as follows:

Case 1 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 0-percent SGTP.

Case 2 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 549°F and 10-percent SGTP.

Case 3 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 0-percent SGTP.

Case 4 Presents the parameter values applicable for NSSS system and component analyses and for accident analyses and evaluations. They include reactor vessel T_{avg} of 572°F and 10-percent SGTP.

Each case was evaluated for two feedwater temperatures, 390.0° and 433.6°F. The low feedwater temperature cases are referred to as case "a" (such as Case 2a), while the high temperature cases are referred to as case "b" (such as Case 2b) for this section of the report. The steam generator secondary side operating characteristics at the SPU conditions are compared with a reference case for the current (100-percent power) condition. The results of

the thermal-hydraulic evaluations are summarized in Table 5.6-1. Based on these evaluations, the IP3 steam generators are qualified to operate at the SPU conditions with up to 10-percent SGTP.

Methodology

A number of secondary side operating characteristics are considered to assess the acceptability of steam generator operation at various operating conditions. These operating characteristics include peak heat flux, margin to departure from nucleate boiling (DNB) transition, moisture carryover (MCO), hydro-dynamic stability, and secondary side pressure drop. The calculation of these steam generator characteristics was accomplished using two programs: the GENF code and the ATHOS code.

GENF is a one-dimensional steady-state thermal and hydraulic performance code developed by Westinghouse specifically for feed-ring steam generators. The code has been verified and is maintained under Westinghouse Configuration Control. GENF calculates the overall primary side heat balance based on the thermal power and the primary flow rate, outlet temperature, and operating pressure. On the secondary side, the code determines the secondary side saturation pressure in the tube bundle using an iterative procedure. The steam outlet pressure is then calculated by subtracting all losses from the bundle region to the steam nozzle outlet. The steam outlet pressure is used to determine steam flow rate via the secondary side heat balance and feedwater inlet temperature. The steam generator operating characteristics obtained using the GENF code, including the circulation ratio, secondary side pressure drop, fluid masses, and stability damping factor, are shown in Table 5.6-1.

The ATHOS code was used to evaluate the potential for local tube dryout or margin to DNB. ATHOS is a three-dimensional computer program for computational fluid dynamics analysis of steam generators. The ATHOS code was developed under the sponsorship of the Electric Power Research Institute (EPRI). The ATHOS code consists of a geometry pre-processor, a thermal-hydraulic (ATHOS) solver, and a post-processor module. The geometry pre-processor simulates the detailed geometry. This geometry simulation includes the detailed tube layout, tube lane blocks, flow distribution baffle (FDB), tube support plates (TSPs), anti-vibration bars (AVBs), and opening of the primary separators. The ATHOS module uses the pre-processor data to calculate the primary and secondary side thermal-hydraulic parameters in the steam generator. The ATHOS code calculates both heat flux and tube wall temperature in addition to typical parameters such as liquid velocity, vapor velocity, and steam quality for a two-phase flow like that in the secondary side of a steam generator.

The ATHOS code for the analysis of steam generators has been verified and qualified by EPRI and Westinghouse. The Westinghouse-developed post-processors process the large amount of output from the ATHOS calculation. Their capabilities include velocity vector plots and contour plots of thermal-hydraulic parameters, such as steam quality, velocity, heat flux, and critical steam quality corresponding to DNB. DNB ratios obtained using the ATHOS code are shown on the last line of Table 5.6-1.

Steam Pressure

Steam pressure is affected by both the available heat transfer area in the tube bundle and the average primary fluid temperature. For the current 100-percent power conditions, the steam pressure is calculated to be 766.18 psia using the Westinghouse GENF code. With the SPU and T_{avg} of 549.0°F, the GENF code shows a decrease in steam pressure to a minimum of [ ]^{a,c,e} psia. With the SPU and T_{avg} of 572.0°F, the GENF code shows a decrease to a minimum of [ ]^{a,c,e} psia. Both of these maximum steam pressure drops occur at a 10-percent SGTP level and are within the acceptable range.

Heat Flux

Average heat flux in the steam generator is directly proportional to heat load and inversely proportional to the heat transfer area in service. For the 0-percent SGTP case, the average heat flux increases from [ ]^{a,c,e} Btu/hr-ft^2 at 100-percent power to [ ]^{a,c,e} Btu/hr-ft^2 at SPU conditions. With 10-percent SGTP and SPU conditions, the average heat flux increases to [ ]^{a,c,e} Btu/hr-ft^2.

Tube Dryout

A measure of the margin for DNB transition in the tube bundle is the DNB index, which is the ratio of the local quality (x) to the estimated quality at DNB transition. The ATHOS code was used to estimate the DNB index of the limiting case for the SPU conditions. Based on the results of the ATHOS program, the highest DNB indexes occur on the hot leg side near the center of the steam generators. The maximum DNB index predicted has a value of [ ]^{a,c,e} and occurs at a small area near the top of the U-bend region. Since the DNB index remains less than 1.0 for the limiting SPU conditions, the whole tube bundle is expected to be within nucleate boiling regime and thus no local tube dryout is expected for any of the SPU conditions.

Moisture Carryover

The performance of moisture separator packages is primarily determined by three operating parameters: steam flow (power), steam pressure, and water level. For the moisture separator performance data evaluation, steam flow and steam pressure are combined into a single parameter designated as the separator parameter (SP). A correlation for MCO as a function of SP is used to predict MCO at desired conditions. The values of the SPs for the IP3 SPU conditions were calculated using the results of the GENF program. The MCO was calculated to possess a maximum of 0.01508 percent of steam flow at the SPU conditions with 10-percent SGTP. Therefore, the MCO is predicted to remain well below the 0.10-percent design limit for SPU conditions.

Hydro-Dynamic Stability

The hydro-dynamic stability of a steam generator is characterized by its damping factor. A negative value of the damping factor indicates that any disturbance to the thermal-hydraulic parameters (for example, flow rate or water level) will rapidly reduce in amplitude and the steam generator will return to stable operation. For the SPU conditions, the damping factor was calculated by the GENF program to range from [ ]^{a,c,e} hr^{-1}, meaning that even the largest damping factor calculated is substantially negative. Therefore, the IP3 steam generators will continue to operate in a hydro-dynamically stable manner at the SPU operating conditions.

Steam Generator Secondary Fluid Inventory

Secondary side fluid inventory consists of the masses of the liquid and the vapor phases. With the proposed SPU, the secondary side fluid liquid mass may vary from [ ]^{a,c,e} lbm. This is a variation of -6.96 percent and +2.73 percent relative to the 100-percent power fluid mass of [ ]^{a,c,e} lbm. The secondary side vapor mass may vary from [ ]^{a,c,e} lbm. This is a variation of -23.43 to -0.99 percent relative to the 100-percent power fluid mass of [ ]^{a,c,e} lbm. Finally, the total secondary side fluid (liquid + vapor) inventory is calculated to vary from [ ]^{a,c,e} lbm for the SPU conditions. These small changes in secondary side fluid inventory are judged to have no effect on operation.

Steam Generator Secondary Side Pressure Drop

The secondary side pressure drop (from the feedwater nozzle the steam exit nozzle) is predicted by GENF program to vary from [ ]^{a,c,e} psi as a result of the SPU. The secondary side pressure drop for the current 100-percent power condition is calculated to be [ ]^{a,c,e} psi. The largest secondary side pressure drop, [ ]^{a,c,e} psi, is predicted with

10-percent SGTP and a T_{avg} of 549.0°F, while the smallest secondary side pressure drop, [ ]^{a,c,e} psi, is predicted with 0-percent SGTP and a T_{avg} of 572.0°F. The small fluctuations in secondary side pressure drop should have no significant effect on the feed system operation.

Thermal-Hydraulic Evaluation Conclusion

In conclusion, the thermal-hydraulic characteristics of the IP3 Model 44F steam generators are within acceptable ranges for the SPU conditions with a SGTP level of 10 percent or less.

5.6.2 Structural Integrity Evaluation

The structural evaluation for the SPU focused on the critical steam generator components. The critical components are those whose primary-plus-secondary stress ranges without peak and stress ranges with peak in fatigue calculations are affected due to the reduction of steam pressure, which results in higher ΔP between primary and secondary side, for the SPU conditions. The critical components are affected by changes in the pressure and temperature in the primary and secondary side of the steam generator. The following critical primary side components were evaluated: divider plate, tubesheet and shell junction, tube-to-tubesheet weld, and tubes. The critical secondary side components included: feedwater nozzle, secondary manway studs, and steam nozzle.

Comparisons of the primary side transients and RCS parameters were performed to determine the scale factors that were applied to the baseline analyses maximum stress ranges and fatigue usage factors. The scale factor was applied to the baseline analysis results for various components to obtain the values for the SPU conditions.

For the primary side components (particularly the divider plate, the tubesheet and shell junctions, the tube-to-tubesheet weld, and tubes), the applicable scale factors were the ratios of the primary-to-secondary-side differential pressure for the baseline and SPU conditions.

The scale factors are applied to the stress ranges that are a combination of both thermal and pressure stresses, and the revised stress ranges are used to calculate the revised alternating stress and the fatigue usage.

For the secondary side components, such as the feedwater nozzle and secondary manway bolts/studs, the decrease in secondary side pressure was the basis for the scale factors. The reduced pressure results in an increased stress range during transient events. The increase in stress range due to the reduced pressure is added to the baseline stress range to evaluate the revised stress range and the revised fatigue usage.

Input Parameters and Assumptions

The SPU structural evaluation was performed for 3230-MWt NSSS power and 10-percent SGTP. The 10-percent SGTP case is the most conservative of the proposed operating cases. The applicable NSSS design parameters used for the steam generator's structural evaluation are shown in Table 2.1-2 of this document. The design transients and the results of the steam generator primary-to-secondary side ΔP calculation (discussed in subsection 5.6.3), were used to generate scaling factors with respect to the design basis stress reports results. The scaling factors were based on the existing design basis steam temperature of 513.8°F, corresponding to a steam pressure of 770 psia.

The NSSS design plant operating conditions provide for both a low T_{avg} temperature operating condition case and a high T_{avg} temperature operating condition (see Table 2.1-2). The low T_{avg} case results in a lower steam pressure (and, therefore, a greater primary-to-secondary side ΔP) and, as such, will envelop the high T_{avg} case. On this basis, the bounding scale factors based on low T_{avg} were used to perform a bounding evaluation of the critical components.

The scale factors calculated based on the differential pressure are applied conservatively on the stress intensities that are due to both pressure and thermal loads, since the scale factors based on pressure will envelop the scale factors based on thermal loads. The evaluation based on scale factors due to ΔP is conservative, since the thermal variation is small.

Description of Analyses and Evaluations

This structural evaluation was performed for the bounding condition for low T_{avg} case, where P_{stm} = 650 psia. The existing design basis evaluation corresponds to the reference NSSS design parameter case of P_{stm} = 770 psia. Scale factors are calculated based on the revised steam pressure at the SPU operating conditions.

<u>Primary Side Components</u>

For primary side components, the scale factor is based on the change in the primary-to-secondary side differential pressure and was calculated based on the following equation:

[ ] a,c,e

Secondary Side Components

Secondary side components, such as the feedwater nozzle, steam nozzle and secondary manway studs, are subjected to only the steam pressure. Therefore, the scale factor is calculated based on the reduced steam pressure during transient events.

The calculated scale factors were applied to the stress ranges for all applicable transient combinations involved in the original reference analysis.

Applying the scale factors to the design basis stresses approximates the stress and fatigue usage values that would occur during operation at the SPU conditions.

Acceptance Criteria

The acceptance criteria for each component are consistent with the criteria used in the design basis analysis for that component. The maximum range of primary-plus-secondary stresses was compared with the corresponding $3S_m$ limits of the ASME Boiler and Pressure Vessel (B&PV) Code, 1965 Edition through Summer 1966 Addenda (Reference 1). For situations in which these limits were exceeded, a plastic analysis or simplified elastic-plastic analysis was performed consistent with the original design basis analysis to meet the American Society of Mechanical Engineers (ASME) Code Section III limits. Results of these original analyses were updated for the SPU conditions.

A cumulative fatigue usage factor less than or equal to unity demonstrates the adequacy of the steam generators for a 40-year design life.

Results

The results of the evaluation show that all components analyzed meet ASME Code Section III limits for a 40-year design life. The results of the evaluation are summarized in Table 5.6-2.

5.6.3 Evaluation of Primary-to-Secondary Side Pressure Differential

An analysis was performed to determine if ASME B&PV Code, (Reference 1) limits on the Model 44F replacement steam generator (RSG) design primary-to-secondary ΔP are exceeded for any of the applicable transient conditions for the SPU parameters (Table 2.1-2). The design pressure limit for primary-to-secondary pressure differential is 1700 psi, as defined in the applicable design specification.

The normal/upset transient conditions are subject to the following design pressure requirements:

- Normal Condition Transients: Primary-to-secondary pressure gradient should be less than the design limit of 1700 psi.

- Upset Condition Transients: If the pressure during an upset transient exceeds the design differential pressure limit, the stress limits corresponding to design conditions apply using an allowable stress intensity value of 110 percent of those defined for design conditions. In other words, as long as the upset condition pressure differential values are less than 110 percent of the design pressure differential values, no additional analysis is necessary. For the IP3 steam generators, 110 percent of the design pressure differential limit corresponds to 1870 psi.

The primary-to-secondary pressure differential evaluation was based on the transient parameters discussed in Section 3.1 of this report and the corresponding full-power conditions that are defined in Table 2.1-2 of this document. The pressure differentials across the primary-to-secondary side pressure boundary are calculated for these defined full-power conditions. Note that the evaluation was performed for the 10-percent SGTP condition since increased levels of plugging result in greater primary-to-secondary pressure differentials. Therefore, the 10-percent SGTP case bounds all other cases.

The analysis determined that the maximum normal/upset operating condition primary-to-secondary side differential pressures (based on Table 2.1-2 of this document) for high T_{avg} operation would be [ ]^{a,c,e} psi for normal operating condition transients, and [ ]^{a,c,e} psi for upset condition transients. For the low T_{avg} operating conditions, the maximum pressure differentials (based on Table 2.1-2 of this document) are [ ]^{a,c,e} psi for the normal and upset conditions, respectively. The results show that the maximum primary-to-secondary pressure gradients are less than the allowable values of 1700 and 1870 psi for normal and upset operating conditions, respectively. Therefore, the design pressure requirements of the ASME Code continue to be satisfied.

5.6.4 Evaluations for Repair Hardware

The IP3 RSGs entered service in 1989. During the fabrication on 1 of the steam generators, several Westinghouse shop welded plugs were installed. These components were re-evaluated for the operating conditions and transients associated with SPU operation.

In anticipation of future needs, both "long" and "short" 7/8-inch ribbed mechanical plugs were qualified for installation in the Model 44F RSGs for the SPU operating conditions. In addition,

since there are circumstances that may require tube ends to be reamed, a 40-percent tube wall undercut was considered. The resulting reduced tube mouth weld joint geometry is qualified for continued service. Also, if a future need arises that a steam generator tube may require stabilization, evaluations were performed to qualify collar-cable tube stabilizers and bare-cable stabilizers.

Mechanical Plugs

The enveloping condition for the Westinghouse mechanical plug (Alloy 690 plug shell material) results in the largest pressure differential between the primary and secondary sides of the steam generator. Both the SPU parameter changes and the updated NSSS design transients were used to determine the effect of the SPU on the mechanical plugs. The most critical set of parameters for the mechanical plug evaluation are those for the primary side hydro-static pressure test in which the differential pressure across the plug is [ ][a,c,e] psi and is independent of the SPU.

Description of Evaluation

A structural evaluation was performed for both "long" and "short" Westinghouse 7/8-inch ribbed mechanical plugs for both the 1.4-percent Measurement Uncertainty Recapture (MUR) Program and the SPU conditions. This evaluation was performed to the applicable requirements of ASME B&PV Code (Reference 1).

Acceptance Criteria

The Westinghouse mechanical tube plug was evaluated for the changes to the NSSS transients due to the SPU. The primary stresses due to design, normal, abnormal, and test conditions must remain within the respective Code allowable values (Reference 1). The maximum range of primary-to-secondary stresses is limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the plug. In addition to the stress criteria, plug retention must be ensured.

Results

The critical loading parameter from the design of the plug shell is the primary-to-secondary differential pressure. The plug qualification was based on a primary pressure of 2485 psig. The maximum design primary-to-secondary differential pressure of 1700 psi for plug retention was also addressed.

All stress/allowable ratios are less than unity, indicating that all primary stress limits are satisfied for the plug shell wall between the top land and the plug end cap. The plug meets the Class 1 fatigue exemption requirements per N- 415.1 of the ASME B&PV Code (Reference 1). It was also determined that adequate preload and friction are available to prevent dislodging of the plug for the limiting steady-state and transient loads.

Since this is a component that is installed into the steam generator after original fabrication is complete, and since this part is typically fabricated to the requirements of the 1989 ASME Code Edition (Reference 2), an evaluation was conducted based on the 1989 Code year requirements. It was determined that the mechanical plug is also acceptable for the SPU operating conditions based on the 1989 ASME Code Edition.

Conclusions

Results of the analyses performed for the mechanical plug for IP3 show that both the long and short mechanical plug designs satisfy all applicable stress and retention acceptance criteria at the SPU operating conditions with up to 10-percent SGTP.

Shop Weld Plugs

The Westinghouse shop weld plugs are fabricated from ASME SB-166, Alloy 600 rod material. The minimum yield for this material is 35,000 psi. Since several design transients were revised for the SPU conditions, a revised analysis was performed to qualify the plugs for the revised conditions.

Description of Evaluation

A structural evaluation was performed for the existing shop weld tube plugs for the SPU operating conditions. The evaluation was performed to the applicable requirements of the ASME B&PV Code (Reference 1).

Acceptance Criteria

The primary stresses due to design, normal, abnormal, and test conditions must remain within the respective ASME Code allowable values (Reference 1). The maximum primary-to-secondary stresses are limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the plug.

Results

The evaluation of the weld plug first addressed the design condition. A vertical minimum weld thickness critical plane around the perimeter (circumference) of the weld plug was considered. The design pressure differential of 1700 psi between the primary and secondary was applied to the plug.

Test conditions for the primary hydro-static and secondary hydro-static tests were then evaluated. Values for primary stresses, primary stresses plus secondary stresses, and primary-to-secondary stress range intensities were calculated. All stress values were determined to be acceptable.

The normal and abnormal conditions were then reviewed. It was determined that the controlling transient for both the normal and abnormal conditions was the "loss of load" transient. The differential pressure considered was [ ]^{a,c,e} psi. This was the controlling pressure condition for the baseline transient conditions. It was determined that the stress limits are acceptable for the controlling differential pressure. However, the governing differential pressure for the SPU was calculated at [ ]^{a,c,e} psi.

The last step in the evaluation process considered fatigue. The approach was to investigate if the weld plug would be exempt from an explicit usage factor calculation based on the ASME requirements for fatigue exemption. The six required fatigue exemption conditions were determined to be satisfied. Therefore, it was concluded that the welded plug does meet the ASME Code cycle load fatigue limits for the SPU.

Conclusions

All primary stresses are satisfied for the weld between the weld plug and the tubesheet cladding. The overall maximum primary-plus-secondary stresses for the enveloping transient case of "loss of load" was determined to be acceptable. The fatigue evaluation for the weld plug used the ASME fatigue exemption rules. It was determined that the fatigue exemption rules were met, and therefore, fatigue conditions are acceptable.

Tube Undercut Qualification

It may be necessary to field machine steam generator tube mouth ends to modify and repair tubes (that is, plugging, sleeving, and tube end reopening). It is sometimes necessary to remove a portion of the tube and weld material with a machining process (drilling and reaming) when removing a Westinghouse mechanical plug. The structural evaluation performed for the SPU conditions addressed the acceptability of up to a 0.020-inch (40-percent of the 0.050-inch

tube wall) undercut of the tube wall thickness. The evaluation was performed to the applicable requirements of ASME B&PV Code (Reference 1).

Description of Evaluation

Past structural evaluations for steam generator tube-end machining have been performed for various steam generator models. The approach for the IP3 tube-end evaluation was to use the results from a previous evaluation and adjust the stress values from the past project as appropriate to address the applicable NSSS transients for the SPU operating conditions.

Acceptance Criteria

The primary stresses due to design must remain within the respective ASME Code allowable values (Reference 1). The maximum range of stress intensities is limited to $3S_m$. The cumulative fatigue usage factor must be less than or equal to 1.0, or the ASME fatigue exemption rules must apply, for a 40-year fatigue life for the undercut tube.

Results

The approach for the IP3 tube-end evaluation was to use the results from past structural evaluations for steam generator tube-end machining and adjust the stress values from the past project as appropriate for design transient changes. The adjustment value was conservatively based on the increase in a differential pressure for the SPU across the tubesheet. It was determined from the results that all revised stresses for the SPU conditions are within ASME Code allowable values.

A similar approach, using stress factors based on increased pressure differentials, was used to evaluate fatigue in the undercut tube. It was determined that fatigue usage values, when adjusted for the SPU conditions, remain acceptable.

Conclusions

The stress evaluation of undercut tubes in the IP3 model 44F steam generators determined that the stresses are within ASME Code allowable values. Also, the fatigue usage factors were determined to remain less than 1.0.

Collar-Cable-Stabilizer Qualification

The Westinghouse collar-cable stabilizer consists of a central coaxial cable made up of Type 302 stainless steel wire strands protected over the full length of the stabilizer by several Type 304 stainless steel tubular collars, which are swaged onto the cable. The swaged collars

are about 8-inches long with a longitudinal space of about 1-inch between the adjacent collar segments. This arrangement provides flexibility and dynamic damping.

Description of Evaluation

The qualification method was employed to show that the wall of an assumed hypothetical fully severed host tube would wear out before the stabilizer collar wore away, should a random wear couple form between the severed host tube and the stabilizer collar. Under these conditions, the central coaxial cable of the stabilizer would remain intact and protected by the collar remnant for the life of the installation. The evaluation approach was based on the relative wear coefficients and cross-sectional areas of the tube and stabilizer, and is independent of the dynamic fluid forces causing potential random vibration of the assumed severed host tube.

Acceptance Criteria

The design intent of the Westinghouse cable stabilizer is that the local tube wall wears out totally before the tubular segment of the stabilizer wears out, thereby providing positive protection from wear of the stabilizer's central co-axial cable for the life of the installation. Also, the worn stabilizer remnant should prevent significant contact with the adjacent tubes.

Results

The qualification was based solely on geometric parameters and the relative wear coefficients between the stabilizer collars and the host tube materials. Should a potentially unstable dynamic condition occur and the tube starts to wear against the stabilizer collar, the tube wall was determined to essentially wear through before the collar wears through (which protects the central co-axial cable for the life of the installation). Also, potentially deleterious contact with adjacent active tubes was determined not to occur.

Conclusions

The evaluation of the straight leg collar-cable tube stabilizer for IP3 model 44F steam generators determined that the 0.625-inch diameter stabilizer is acceptable for use in the 0.875-inch diameter, 0.050-inch nominal wall tubes, for operation at the SPU conditions.

Bare-Cable Stabilizer Qualification

The Westinghouse bare-cable stabilizer's function is to retain severed tubes, to dampen vibration and to mitigate additional wear on plugged steam generator tubes. The tube stabilizer is fabricated from 0.5-inch diameter 6 x 19 Type 304 stainless steel wire rope. It has a lower end fitting that allows it to be installed with a typical probe pusher. The upper end of the

stabilizer is capped with a welded bullet nose to facilitate installation. This stabilizer is used in the same manner as the collar -cable stabilizer discussed previously.

Description of Evaluation

It has been previously demonstrated that the bare-cable tube stabilizer is acceptable generically for use in Westinghouse-designed steam generators with 7/8-inch tubing. The generic design was based on the original Sequoyah Units 1 and 2 steam generators and is generally applied to defects below the first tube support. However, longer lengths of this stabilizer design can be applied to defects anywhere along the straight length of the tubing. A review of the generic bare-cable stabilizer analysis and the SPU thermal-hydraulic conditions shows that the existing qualification of the stabilizer remains valid for the SPU conditions at IP3.

Both IP3 and Sequoyah have similar Westinghouse steam generator designs. The tube support geometry for both designs is essentially the same except the Model 44F steam generators at IP3 have a flow distribution baffle (FDB) located approximately 23 inches up from the secondary face of the tubesheet. However, this baffle is not assumed to provide any support for the tubes. Thus, the free-span region of the tube at the entrance to the tube bundle is essentially the same for both steam generator designs. Other assumptions used in the generic bare-cable stabilizer analysis (for example, threshold instability constant, tube inside diameter [ID] and outside diameter [OD], damping ratio, etc.) are the same for both Sequoyah and IP3.

Comparisons of the SPU operating conditions for IP3 and those considered in the qualification of the stabilizers for Sequoyah were used to determine the applicability of the generic analysis to IP3.

Acceptance Criteria

The bare-cable stabilizer design is considered qualified if the tube with the stabilizer installed remains fluid-elastically stable for operation at the SPU conditions. That is, the stability ratio of a tube with a bare-cable stabilizer must be less than or equal to 1.0.

Results

A review of the thermal-hydraulic analysis shows that the SPU results in a maximum increase in fluid velocities at the tube bundle entrance of no more than 3-percent. More significantly, the dynamic pressure (ρV^2) of the fluid against the tubes increases by approximately 4-percent for the worst case analyzed. To account for these potential differences, the previous generic bare-cable stabilizer evaluation included secondary side flow velocities increased by 50 percent and the unsupported tube span at the tube bundle entrance lengthened by 25 percent. Even with these overly conservative assumptions, the stability ratio remains less than 1.0, and the tube

movements would be less than the defined limits, as such the results are acceptable. Thus, the existing qualification for the bare-cable stabilizer is bounding for the SPU operating conditions proposed for the IP3 steam generators.

Conclusions

The bare-cable tube stabilizer is acceptable for use in the IP3 steam generator at the SPU conditions.

5.6.5 Regulatory Guide 1.121 Analysis

The heat transfer area of steam generators in a pressurized water reactor (PWR) NSSS comprises over 50 percent of the total primary system pressure boundary. The steam generator tubing, therefore, represents a primary barrier against the release of radioactivity to the environment. For this reason, conservative design criteria have been established for the maintenance of tube structural integrity under the postulated design basis accident (DBA) condition loadings in accordance with Section III of the ASME Code.

Over a period of time under the influence of the operating loads and environment in the steam generator, some tubes may become degraded in local areas. Partially degraded tubes are satisfactory for continued service as long as the defined stress and leakage limits are satisfied, and as long as the prescribed structural limit is adjusted to account for possible uncertainties in the eddy current inspection and an operational allowance for continued tube degradation until the next scheduled inspection.

NRC Regulatory Guide (RG) 1.121 (Reference 3) describes an acceptable method for establishing the limiting safe condition of tube degradation beyond which tubes determined to be defective by the established in-service inspection should be removed from service. The level of acceptable degradation is referred to as the "repair limit." For tube cracking due to fatigue and/or stress corrosion, a specification on maximum allowable leak rate during normal operation must be established so that a reasonable likelihood that "leak-before-break" would be achieved. If the leak rate exceeds the specification, the plant must be shut down and corrective actions taken to restore the integrity of the unit. The EPRI *PWR Primary-to-Secondary Leak Guidelines* (Reference 4) form the basis of the plant's operational leakage program.

Description of Evaluation

An analysis has been performed to define the "structural limits" for an assumed uniform thinning mode of degradation in both the axial and circumferential directions. The assumption of uniform thinning is generally regarded to result in a conservative structural limit for all flaw types occurring in the field. The allowable tube repair limit, in accordance with RG 1.121

(Reference 3), is obtained by incorporating a growth allowance for continued operation until the next scheduled inspection and also an allowance for eddy current measurement uncertainty into the resulting structural limit. Calculations have been performed to establish the structural limit for the tube straight leg (free-span) region of the tube for degradation over an unlimited axial extent, and for degradation over limited axial extent at the TSP, FDB, and AVB intersections.

Results and Conclusions

A summary of the tube structural limits as determined by this analysis for both the high T_{avg} and low T_{avg} operating conditions is provided in Table 5.6-3. The corresponding repair limits are established by subtracting from the structural limits an allowance for eddy current uncertainty and continued growth. The reduced minimum tube wall thickness (t_{min}) requirements established for the AVB intersections in Table 5.6-3 only apply for tube rows 17 and higher. The t_{min} requirements and structural limits corresponding to the straight leg are to be used for AVB intersections in tube rows 9 to 16.

5.6.6 Tube Vibration and Wear

The effect of the proposed SPU on the steam generator tubes was evaluated based on the current design basis analysis and included the changes in the thermal-hydraulic characteristics of the secondary side of the steam generator resulting from the SPU. The effects of these changes on the fluid-elastic instability ratio and amplitudes of tube vibration due to turbulence have been addressed. In addition, the effects of the SPU on potential future tube wear have also been considered.

Description of Analyses and Evaluations

The baseline tube vibration and wear analysis results for the IP3 Model 44F RSG were used for comparison. The original vibration analysis demonstrated that the maximum fluid-elastic stability ratio for the expected tube support conditions was less than the allowable limit of 1.0. The original tube vibration analysis also determined that negligible tube responses occurred due to the vortex-shedding mechanism. The amplitudes of vibration due to turbulence were also determined to be reasonably small with maximum displacements that were determined to be on the order of [ ]^{a,c,e}. The maximum expected tube wear that could occur over the remaining period of operation was calculated to be [ ]^{a,c,e}.

The results of the vibration and wear analysis were modified to account for anticipated changes in secondary side operating conditions due to the SPU. The following is a summary of results.

For the expected support conditions, it was determined that straight leg stability ratios were not significantly affected. However, the stability ratio for U-bend conditions increased from [ ]a,c,e, which is still less than the allowable limit of 1.0. As a result, the analysis indicated that large amplitudes of vibration are not projected to occur due to the fluid-elastic mechanism while operating the steam generator in the SPU condition.

The maximum displacement values calculated for turbulence excitation in the original analysis were modified to account for SPU- induced changes in the operating conditions. For the most limiting tube support condition, it was determined that the turbulence-induced displacement could increase to [ ]a,c,e. Displacements of this magnitude are not sufficient to produce tube-to-tube contact. However, the potential for tube wear must be considered.

As in the original analysis, the vortex-shedding mechanism was determined not to be a significant contributor to tube vibration, which continues to be the case for operation in the post-SPU condition.

The potential for tube wear was addressed in the original analysis that addressed wear in both the straight leg and U-bend portions of the steam generator. These calculations were then updated to reflect operation of the steam generator at SPU conditions. The calculation determined that the level of tube wear that could occur would increase from [ ]a,c,e at the SPU conditions. From these calculations it can be concluded that although there may be an increase in the level of wear that could occur at the SPU operating conditions, the increased level would not be significant. Any increase in the rate of tube wear would progress over many cycles and would be observable during normal eddy current inspections, at which time remedial action could be taken.

Note that as of the 3R12 outage, no AVB wear was reported. It should be noted that there is no direct correlation of flow-induced vibration with primary-to-secondary side pressure differences. The steam generator tubes respond primarily to the conditions associated with the secondary side since the forcing functions associated with the secondary side of the steam generator dominate any other effects. Any effects of primary-to-secondary side pressure difference are inherently considered in the analysis in that the secondary side conditions are defined by the total steam generator conditions such as steam pressure, flow rates, re-circulation, etc., and include the primary-to-secondary side pressure difference.

In some model steam generators, particular consideration is given to the potential for high cycle fatigue of U-bend tubes. This phenomenon has been observed in tubes with carbon steel support plates where denting or a fixed tube support condition has been observed in the uppermost plate. However, since the IP3 steam generator TSPs are manufactured from stainless steel, there is no potential for the necessary boundary conditions (that is, denting) to

occur at the uppermost support plate. Hence, high-cycle fatigue of U-bend tubes is not an issue for the IP3 Model 44F steam generators.

Conclusions

The analysis of the IP3 Model 44F RSGs indicates that significant levels of tube vibration will not occur from the fluid-elastic, vortex-shedding, or turbulent mechanisms as a result of the proposed SPU. In addition, the projected level of tube wear as a result of vibration can be expected to remain small and not result in unacceptable wear. High cycle fatigue at U-bend tubes is not an issue for concern at IP3.

5.6.7 Tube Integrity

Over a period of time, some tubes can become degraded locally under the influence of the operating loads and chemical environment in the steam generator. Degradation mechanisms observed in the first generation steam generators (for example, those using mill annealed [MA] Alloy 600 tubing) include OD stress corrosion cracking (ODSCC), primary water stress corrosion cracking (PWSCC), pitting, as well as tube wear at AVBs and TSPs due to tube vibration, and potentially at other locations such as the FDB, due to maintenance operations. The potential for these degradation mechanisms affecting the IP3 steam generators due to the SPU is discussed below.

The IP3 steam generators are Model 44F steam generators containing thermally treated Alloy 690 tubing and ASME SA-240 TSPs with broached quatrefoil (concave) holes. The first eight rows of tubes were heat treated after bending to relieve stresses. Performance of the RSGs has been exceptional with no indications of corrosion related tube degradation up to the end of cycle 12 (Reference 5).

According to laboratory testing conducted over several years by several independent organizations, Alloy 690TT is substantially more resistant to cracking than Alloy 600MA. Alloy 690TT has cracked in laboratory tests in high temperature water with characteristics similar to those of current steam generator secondary environments. Although it has not been completely immune to SCC in laboratory tests in caustic conditions, occurrences of SCC in Alloy 690TT have been relatively rare in laboratory conditions. SCC of steam generator tubing is believed to follow an Arrhenius relationship, yet no SCC has been observed in any operating steam generator with Alloy 690TT tubing.

Alloy 690TT operating experience in RSGs tubed with thermally treated Alloy 690 has confirmed its corrosion resistance. Since mid-1989, all new and replacement SGs manufactured by Westinghouse, CE, and BWI in the U.S. and most foreign vendors have used Alloy 690TT as

the heat transfer tubing (and other components subject to corrosion as well). This includes 17 Westinghouse/CE PWRs and approximately 57 non-Westinghouse/CE PWRs which are operating with Alloy 690TT tubing. The Westinghouse/CE replacements have been operating for two to ten effective full-power years (EFPYs) at hot leg temperatures in the range of 596° to 620°F. Not a single incident of tube plugging due to environmental degradation has been reported in those steam generators. The highest reactor outlet temperature, 603.0°F, for the IP3 SPU is near the bottom of that range. IP3 SPU parameters used for this work are listed in Table 2.1-2 of this report. The more conservative parameters will be used for this analysis.

Secondary side steam generator chemistry has contributed to tube cracking in some units with A600MA tubing. Concentration of caustic solutions in areas of stress concentration aids the initiation of cracking. ODSCC has not been reported in any plant with Alloy 690TT tubing in approximately 15 years of operation. The presence of this condition is detectable by eddy current examination using EPRI-qualified bobbin, motorized rotating probe coil (MRPC), and array probe techniques. Thus, if any tubes in the IP3 steam generators contain a similar material condition, these tubes can be identified and effectively monitored by nondestructive examination (NDE).

In addition to enhanced tube materials of construction, the IP3 steam generators use design features that have been shown to effectively reduce the potential for SCC initiation. These include hydraulically expanded tubes in the tubesheet region, quatrefoil-broached tube hole design with stainless steel TSP material, and supplemental thermal treatment of the Row 1 through 8 U-bends following bending. Hydraulic expansion of the tubes in the tubesheet region results in reduced residual stresses compared to mechanical roll expansion and a more uniform expansion compared to explosively expanded tubes. The broached tube hole condition results in reduced potential for contaminant concentration at TSP intersections by reducing the crevice area. Supplemental thermal treatment of the row 1 through 8 U-bends following bending was performed to reduce residual stresses to near straight leg region levels. For thermally treated Alloy 690 U-bends, already highly resistant to PWSCC, this stress relief process ensures that the expected resistance to PWSCC is not diminished in the small-radius U-bends.

Potential tube degradation mechanisms due to potential localized chemistry changes at the tube surfaces after the SPU in the IP3 RSGs are ODSCC and pitting. Other degradation mechanisms are either mechanical and evaluated earlier in this report or are not relevant to IP3 RSGs. Based on laboratory and operating experience and present operating and maintenance practices at IP3 the SPU will not increase the propensity of degradation due to those mechanisms.

5.6.8 References

1. *ASME Boiler and Pressure Vessel Code* Section III, "Nuclear Vessels," 1965 Edition, Summer 1966 Addendum, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code Section III*, "Rules for the Construction of Nuclear Power Plant Components," 1989 Edition, ASME, New York, NY.

3. NRC Regulatory Guide 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes (for comment)*, August 1976.

4. EPRI Report TR-104788-R2, *PWR Primary-to-Secondary Leak Guidelines – Revision 2*, EPRI, Palo Alto, CA, 2000.

5. Report Number SG-SGDA-02-42, *Steam Generator Degradation Assessment for Indian Point Unit 3 RFO*-12, February 2003.

Table 5.6-1

Thermal-Hydraulic Characteristics of IP3 Steam Generators

	Ref. Case	With Uprate to 3230-MWt NSSS Power			
Case	3082 MWt	1a / 1b	2a / 2b	3a / 3b	4a / 4b
RCS T_{avg} °F	571.5	549.0	549.0	572.0	572.0
Operating Conditions					
Power - %	100	104.8	104.8	104.8	104.8
NSSS Power - MWt	3082	3230	3230	3230	3230
Power - MWt/SG	770.5	807.5	807.5	807.5	807.5
Primary Temps. - °F					
SG T_{hot} – °F	600.8	580.3	580.3	602.5	602.5
SG T_{cold} – °F	541.9	517.0	517.0	540.7	540.7
Primary Flow - gpm	89,700	88,600	88,600	88,600	88,600
Feed Temp. - °F	427.8	390.0 / 433.6	390.0 / 433.6	390.0 / 433.6	390.0 / 433.6
Fouling - hr-ft^2-°F/Btu x 10^6	0.00011	0.00011	0.00011	0.00011	0.00011
Plugging - %	0	0	10	0	10
Operating Characteristics					a,c,e
Steam Flow/SG - 10^6 lbm/hr					
Steam Press$^{(1)}$ - psia					
Circulation Ratio					
Downcomer Velocity - ft/sec					
Total Secondary ΔP - psi					
Secondary Fluid Liquid Mass - lbm					
Secondary Fluid Vapor Mass - lbm					
Secondary Fluid Heat Content - 10^6 Btu					
Average Heat Flux - Btu/hr-ft^2					
Damping Factor - hr^{-1}					
Overall Resistance - hr-ft^2-°F/Btu					
Peak Heat Flux - Btu/ft^2-hr					
Separator Parameter					
MCO – weight %					
Operating Characteristics					
Maximum (X/X_{DNB})$^{(2)}$	NA	NA	0.9105 / NA	NA	NA

Note:

1. Table 2.1-2 steam pressures differ slightly from these values as a result of different codes used and different calculations of internal pressure drop.
2. Ratio of local quality to quality at DNB based on ATHOS runs. ATHOS analysis was performed only for Case 2a.
3. The low feedwater temperature cases are referred to as case "a" (such as Case 2a), while the high temperature cases are referred to as case "b" (such as Case 2b) for this section of the report.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.6-2 IP3 SPU Evaluation Summary Primary and Secondary Side Components						
Component	**Load Condition**	**Stress Category**	**Stress (ksi)/ Fatigue - Baseline**	**Stress (ksi)/ Fatigue SPU**	**Allow (ksi)/ Fatigue**	**Comments**
Primary Side Components						
Divider Plate	Normal/Upset	P_m+P_b+Q (1)		a,c,e	69.90	Note 4
		Fatigue			1.00	
Tubesheet & Shell Junction	Normal/Upset	P_m+P_b+Q			80.10	Note 4
		Fatigue			1.00	
Tube- to-Tubesheet Weld	Normal/Upset	P_m+P_b+Q			69.90	Note 2
		Fatigue			1.00	
Tubes	Normal/Upset	P_m+P_b+Q			79.80	
		Fatigue			1.00	
Secondary Side Components(2)						
Main Feedwater Nozzle	Normal/Upset	P_m+P_b+Q			80.10	Note 1
		Fatigue			1.00	
Secondary Manway Stud	Normal/Upset	P_m+P_b+Q			94.50	Note 1, 5
		Fatigue(3)			1.00	
Steam Nozzle	Normal/Upset					
Limiting Section		P_m+P_b+Q			80.10	Note 1
		Fatigue inside			1.00	
Insert		P_m+P_b+Q			56.07	Note 1, 3
		Fatigue			1.00	
Support Ring		P_m+P_b+Q			36.50	Note 1, 3
		Fatigue			1.00	

Note

1. Additional stress due to reduction of pressure is taken to calculate the increase in stress range for secondary side components.
2. Conservative high fatigue strength reduction factors (per NB-3228.5) are used with elastic stresses in the fatigue evaluation in place of simplified plastic analysis.
3. Exceeds $3S_m$. Simplified Elastic plastic analysis was done in the reference analysis for fatigue evaluation demonstrates code compliance
4. Exceeds $3S_m$. Plastic analysis done in the reference analysis for fatigue evaluation demonstrates code compliance.
5. $94.5 = 2.7S_m$

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.6-3 Summary of Tube Structural Limits RG 1.121 Analysis			
Location/Wear Scar Length	**Parameter**	**High T_{avg}**	**Low T_{avg}**
Straight Leg and AVB/ 1.50 inch (Tub Rows 9-16)	t_{min} (inch)	[	]a,c,e
	Structural Limit (%)(1)		
AVB(2) / 0.9 inch Tube Rows 17-45)	t_{min} (inch)		
	Structural Limit (%)(1)		
FDB/0.75 inch	t_{min} (inch)		
	Structural Limit (%)(1)		
TSP/1.125 inch	t_{min} (inch)		
	Structural Limit (%)(1)		

Notes:

1. Structural Limit = [(t_{nom} - t_{min}) / t_{nom}] x 100 percent
   t_{nom} = 0.050 in
2. The tube structural limits and minimum thickness specified for the AVB applies only for tube rows 14 and higher. For tube/AVB intersections for tube rows 1 to 13, the structural limits and minimum thickness for the FDB locations are to be used.

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.7 Pressurizer

5.7.1 Structural Analysis

The pressurizer absorbs any expansion or contraction of the primary reactor coolant due to changes in temperature and pressure and, in conjunction with the pressure control system components, keeps the Reactor Coolant System (RCS) at the desired pressure. The first function is accomplished by keeping the pressurizer approximately half-full of water and half-full of steam at normal conditions, allowing inflow to, or outflow from, the pressurizer as required via a connection to the RCS at the hot leg of one of the reactor coolant loops (RCLs). The second function is accomplished by keeping the temperature in the pressurizer at the water saturation temperature (T_{sat}) corresponding to the desired pressure. The temperature of the water and steam in the pressurizer can be raised by operating electric heaters at the bottom of the pressurizer and can be lowered by introducing relatively cool spray water into the steam space at the top of the pressurizer.

The components in the lower end of the pressurizer (such as the surge nozzle, lower head/heater well, and support skirt) are affected by pressure and surges through the surge nozzle. 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 pressure, spray flow through the spray nozzle, and temperature differences between the pressurizer steam and the spray water.

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. This maximizes the ΔT that is experienced by the pressurizer. Due to flow out of, and into, the pressurizer during various transients, the surge nozzle alternately sees water at the pressurizer temperature (T_{sat}) and water from the RCS hot leg at T_{hot}. If the RCS pressure is high (which means, correspondingly, that T_{sat} is high) and T_{hot} is low, then the surge nozzle will see maximum thermal gradients (ΔT_{hot} = temperature difference between T_{hot} and the pressurizer [surge nozzle] temperature) and, thus experience the maximum thermal stress. Likewise, the spray nozzle and upper shell temperatures alternate between steam at T_{sat} and spray water, which, for many transients, is at T_{cold}. Thus, if RCS pressure is high (T_{sat} is high) and T_{cold} is low, then the spray nozzle and upper shell will also experience the maximum thermal gradients (ΔT_{cold} = temperature difference between T_{cold} and the pressurizer [spray nozzle] temperature) and thermal stresses.

By evaluating the surge and spray nozzles, all other components are qualified. These evaluations were performed to support the IP3 SPU to address the effect of the SPU on the pressurizer. This evaluation is based on the range of NSSS operating parameters to support a NSSS power level of 3230 MWt (see Table 2.1-2 in Section 2 of this report).

The reactor vessel outlet (T_{hot}) and the reactor vessel/core inlet (T_{cold}) temperatures from Table 2.1-2 define the normal operating temperatures for the surge and spray lines to the pressurizer. The reactor coolant pressure defines the pressurizer normal operating pressure (2250 psia) and saturated temperature (653°F). The minimum values of T_{hot} and T_{cold} from all cases were used in the evaluation of the pressurizer. The NSSS design transients are also applicable to the pressurizer and were considered in the analysis.

The input parameters associated with the IP3 SPU were reviewed and compared to the design inputs considered in the current pressurizer stress report. In cases for which revised input parameters are not obviously bounded, pressurizer structural analyses and evaluations were performed, and reviewed against hand calculations using appropriate engineering assessments. Any effects to the existing design basis analysis were evaluated through a comparative analysis of the changes. This method involves a simplified engineering approach, using the existing analyses as the basis of evaluation. It uses scaling factors to assess the effect of the changes in the parameters such as the system transients, temperatures, and pressures. New stresses and revised cumulative usage factors (CUFs) are calculated, as applicable, and compared to previous results. The evaluation results show that conformance to the ASME Code-allowable limits is maintained. Since the change in the ΔT_{hot} was minimal and bounded by the original design basis calculations, no analyses were necessary for the lower shell and its key components. Only the change in the ΔT_{cold} warranted an analysis of key upper shell components such as the spray nozzle, the safety and relief nozzle, and the upper shell itself.

Conclusions

The analysis shows that the SPU will have a limited effect on the IP3 pressurizer components. Table 5.7-1 compares the fatigue usages calculated for the SPU conditions with those reported from the original design basis. The largest increase was for the spray nozzle for which the fatigue usage increased from [ ]a,c,e to [ ]a,c,e. The fatigue usage for the upper shell decreased significantly due to use of more realistic assumptions on spray effects than were used in the original evaluation. The results for the analyzed components, as shown on Table 5.7-1, envelop all other pressurizer components.

It is concluded that the pressurizer components meet the stress and fatigue analysis requirements of the ASME Code, Section III (Reference 1) for plant operation at the SPU conditions.

5.7.2 References

1. *ASME Boiler and Pressure Vessel Code,* Section III, "Rules for Construction of Nuclear Vessels," 1965 Edition through Summer 1966 Addenda, The American Society of Mechanical Engineers, New York, NY.

Table 5.7-1 IP3 Pressurizer Component Fatigue Usage Comparison		
Component	Revised Fatigue Usage	Previous Fatigue Usage
Spray Nozzle (node 441)	[	]a,c,e
Upper Shell (stress difference S31)		
Safety & Relief Nozzle (location 28 inside)		]

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

5.8 Nuclear Steam Supply System Auxiliary Equipment

5.8.1 Introduction

The Nuclear Steam Supply System (NSSS) auxiliary equipment is defined as the equipment contained in the NSSS fluid systems, which are the Reactor Coolant System (RCS), the Chemical and Volume Control System (CVCS), the Residual Heat Removal System (RHRS), the Safety Injection System (SIS), the Component Cooling Water System (CCWS), the Primary Sampling System (PSS), and the Containment Spray System (CSS).

The NSSS auxiliary equipment (auxiliary tanks, heat exchangers [HXs], pumps and valves) were reviewed on a system basis for potential effects due to the revised NSSS parameters (the maximum operating temperatures, pressures, and flow rates in Table 2.1-2 in this report) and the revised design transients resulting from the Indian Point Unit 3 (IP3) stretch power uprate (SPU) conditions as discussed in Section 3 of this report. The evaluation consisted of a structural and flow capacity review of the component pressure boundaries.

5.8.2 Input Parameters and Assumptions

The NSSS parameters provided in Section 2.1 reflect the effect of the SPU on the NSSS system operating temperatures and pressures. This information was applied where applicable for evaluation of the auxiliary equipment maximum operating temperatures and pressures. Section 3.2 discusses the effect of the SPU on the NSSS auxiliary equipment design transients for the auxiliary tanks, HXs, pumps and valves subject to these transients. Section 3.1 defines the effect of the SPU on the NSSS design transients for the auxiliary system valves subject to these transients.

The evaluation of the NSSS auxiliary equipment was made relative to the technical requirements for the NSSS auxiliary equipment as originally supplied by Westinghouse.

5.8.3 Description of Analyses and Evaluations

The original design parameters, including design temperature, pressure, thermal transients, and flow rates were reviewed for the auxiliary tanks, HXs, pumps and valves. These parameters were compared to those used in the SPU, from Sections 2.1 and 3 of this report, to determine if the design parameters still enveloped those for the SPU.

5.8.3.1 Auxiliary System Tanks

None of the tanks have significant transients identified as part of the original design. From an evaluation of the data and parameters discussed in Sections 2.1 and 3, the operating temperatures and pressures for these vessels remain within the design basis for these tanks, and the SPU transients remain bounded by the original design transients.

5.8.3.2 Auxiliary System Heat Exchangers

The NSSS auxiliary HX specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures.

Based on a comparison to the NSSS parameters for the SPU, the operating temperature and pressure ranges for these vessels remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment bound the transients associated with the SPU. The HXs identified in the original design specifications as having transients are the regenerative, letdown, excess letdown, and RHR HXs. All of these temperatures remain bounded by the original design conditions. The RHRS HXs have been structurally evaluated for limiting operating flows during the post-loss-of-coolant-accident (post-LOCA) recirculation phase due to various pump alignments. These flow rates exceed the original design flows for the RHR HXs. The evaluation indicated the HXs were acceptable for these flows. Therefore, these flows remain valid for the SPU condition as well as the original power condition.

5.8.3.3 Auxiliary System Pumps

The NSSS auxiliary pump specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures. For the SPU conditions, the operating temperature and pressure ranges for these pumps remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment bound the transients associated with the SPU.

5.8.3.4 Auxiliary System Valves

The NSSS auxiliary valves specifications identify the applicable design transients, and the data sheets identify the design temperatures and pressures. For the SPU conditions, the operating temperature and pressure ranges for the valves remain bounded by the original design parameters. Section 3 indicates that the original design transients for the auxiliary equipment remain bounded for the transients associated with the SPU.

5.8.4 Acceptance Criteria and Results

If the maximum system operating temperatures, pressures, and flow rates for the SPU are bounded by the original system design conditions, then the auxiliary tanks, HXs, pumps, and valves are considered to be qualified for the SPU.

If the original design transients bound the revised SPU design transients for the auxiliary tanks, HXs, pumps, and valves, then the auxiliary tanks, HXs, pumps, and valves are considered to be qualified for the SPU.

5.8.5 Conclusions

The IP3 auxiliary tanks, HXs, pumps and valves are acceptable for the SPU conditions, since the SPU NSSS parameters are bounded by the original NSSS design parameters (for example, maximum and minimum temperatures) and the original auxiliary equipment design transients.

5.9 NSSS Components Fracture Integrity

5.9.1 Introduction

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) involves changes that affect each of the primary Nuclear Steam Supply System (NSSS) components. This section addresses the effects of the SPU on the fracture integrity of the ferritic Class 1 components, specifically the reactor vessel, steam generators, and pressurizer. These are the components for which non-ductile failure must be considered, according to the requirements of the *American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code,* Section III (Reference 1).

The IP3 reactor vessel was designed to Section III of the 1965 ASME Code (Reference 2). The non-ductile failure requirements were not incorporated into the Code until Appendix G was added to the 1972 Summer Addenda and therefore, there was no Appendix G analysis of record for IP3. Consequently, a base analysis for the IP3 reactor vessel was developed as part of this task.

IP3 has the Model 44F steam generator and a Model 44F pressurizer (the Model 44F pressurizer has the same dimensions and materials as the Model D Series 84 pressurizer). Generic analyses were used for Appendix G qualification of the steam generator and pressurizer, respectively. These generic analyses were used as the base analyses for these components to assess the effect of the SPU.

5.9.2 Input Parameters and Assumptions

The key input parameters are the stresses in the various components and the fracture properties of the components. The fracture integrity evaluations for the SPU draw on the ASME Code design re-evaluations for the reactor vessel, steam generator components, and pressurizer in Sections 5.1, 5.6, and 5.7 of this report, respectively.

The stresses for the baseline reactor vessel analysis were taken from a similar reactor vessel fracture analysis. The original design transients were considered in that reactor vessel fracture analysis, and have been updated to account for the transients discussed in Section 3 of this report.

The stresses for the baseline steam generator analysis were taken from a typical Model 44F replacement steam generator (RSG) stress report. The Model D Series 84 pressurizer analysis was used as the base analysis for the IP3 pressurizer. The stresses obtained from those analyses were adjusted using scale factors previously discussed in Sections 5.6 and 5.7 of this report.

5.9.3 Description of Analyses and Evaluations

5.9.3.1 Methodology

The approach used in these evaluations is a direct application of ASME B&PV Appendix G of Section III (Reference 1). A flaw is postulated, and the crack driving force or stress intensity factor is calculated after adding a safety factor of 2.0 on the primary stresses. The applied stress intensity factor is then compared with the material fracture toughness, as characterized by the reference stress intensity factor (K_{IR}) toughness curve contained in Appendix G. The following sections detail each of these steps.

5.9.3.2 Stress Intensity Factor Calculations and Postulated Flaw Size

The maximum defect assumed in Appendix G (Reference 1) is a sharp surface defect normal to the direction of the maximum stress. The typical flaw is assumed to be semi-elliptical with an aspect ratio of 6:1 and a depth of one quarter of the vessel wall thickness.

Appendix G (Reference 1) recognizes that some regions cannot be expected to meet the requirements of a one-quarter thickness defect; it states that "smaller defect sizes may be used on an individual case basis if a smaller size of maximum postulated defect can be assured." Welding Research Bulletin 175, *PVRC Recommendations on Toughness Requirements for Ferritic Materials* (Reference 3), provides procedures for considering postulated defect sizes smaller than one quarter of the wall thickness.

The combination of examinations originally required by ASME B&PV Section III (Reference 1) (radiography and surface exams) and the volumetric examination required by Section XI (ultrasonic mapping) are capable of detecting flaws of the magnitude of those assumed for the discontinuity regions for the SPU analyses.

The stress intensity factor, K_I, was calculated for both primary and secondary stress for the limiting transients.

The value of K_I depends on:

- The geometry of the body in which the crack is postulated
- The shape and size of the crack
- The mode and the magnitude of the stress distribution at the crack surface

The general formula of K_I is

$$K_I = M_m \sigma_m + M_b \sigma_b$$

where:

M_m, M_b = the correction factors for membrane and bending stresses, respectively (depend on the depth and aspect ratio of the crack - see Figure 5.9-1)

σ_m, σ_b = membrane and bending stresses (calculated as if no crack were present)

The general formula is valid for a semi-elliptical surface flaw in both primary and secondary stress conditions.

K_I for primary and secondary stresses should be added to obtain the combined stress intensity factor. Appendix G (Reference 1) requires that a safety factor of 2 be applied to the K_I of primary stresses in normal and upset conditions. A safety factor of 1.5 is to be used for test conditions. Therefore,

$$[K_I] \text{ combined} = 2\,[K_I] \text{ primary} + [K_I] \text{ secondary}$$

for normal and upset conditions, and

$$[K_I] \text{ combined} = 1.5\,[K_I] \text{ primary} + [K_I] \text{ secondary}$$

for in-service leak and hydrostatic (ISLH) test conditions.

The methodology and the correction factors for calculation of the stress intensity factor for all analyzed regions were taken directly from Appendix G (Reference 1). The expression in Appendix G was developed for a flat plate geometry, but has also been found to be applicable to large-diameter vessels. The same expression can be used to model flaws in the nozzle corner region by setting the plate thickness equal to the nozzle corner throat thickness.

5.9.3.3 Determination of the K_{IR} Curve

The principles of linear elastic fracture mechanics (LEFM) serve as a basis for the evaluation methods of Appendix G of ASME Section III (Reference 1). The central parameter of LEFM is the crack opening mode stress intensity factor K_I. This single parameter defines the elastic stress field in the vicinity of a crack tip. K_I is dependent on the geometry of the body containing the crack, the crack size and shape, and the magnitude and distribution of the stress. A defect will grow unstably whenever K_I exceeds a critical value, K_{IC}, the fracture toughness. The fracture toughness is a material property, dependent on strain rate and temperature. It is also dependent on the metallurgical condition, that is, it changes with microstructure, neutron irradiation, and other metallurgical conditions.

For stress intensity factor rates below 2.5 ksi $\sqrt{in.}$/second (the static range), the fracture toughness is indicated by K_{Ic}, whereas for higher strain rate (the dynamic range), the critical stress intensity factor is indicated by K_{Id}. A third LEFM parameter, the arrest fracture toughness, K_{Ia}, is the value at which a fast-running crack (unstable propagation) will eventually stop. K_{Ic} values are invariably higher than K_{Id} or K_{Ia} values.

The K_{IR} curve essentially represents the lower bound static, dynamic and crack arrest critical K_I values measured as a function of temperature on specimens of SA-533 Grade B Class 1, and SA-508-1, 2, and 3 steel. No available data points for static, dynamic, or arrest tests fall below the curve for K_{IR}.

The temperature scale is defined relative to the reference nil ductility transition temperature, RT_{NDT}. The RT_{NDT}, a nonphysical constant that is related to the brittle-to-ductile fracture transition temperature, is determined by both drop weight tests and Charpy V notch impact tests.

A typical reference fracture toughness curve (K_{IR} versus temperature) is presented in Figure 5.9-2 (Figure G-2110-1 of Reference 1). To facilitate analytical calculations, the equation representing this curve can be expressed as:

$$K_{IR} = 26.78 + 1.233 \exp [0.0145 (T - RT_{NDT} + 160)]$$

Where:

K_{IR} = reference stress intensity factor, ksi $\sqrt{in.}$

T = temperature at which K_{IR} is permitted, °F

RT_{NDT} = reference nil ductility temperature, °F

A K_{IR} upper shelf of 200 ksi$\sqrt{in.}$ has been adopted for unirradiated material, and a shelf of 170 ksi$\sqrt{in.}$ has been fixed for irradiated material provided the upper shelf Charpy energy exceeds 50 ft lb. This is a generally accepted industry practice, as shown for example in EPRI Report NP-7195R (Reference 4).

Neutron irradiation adversely affects the toughness properties of the reactor vessel steel. The neutron embrittlement of the steel has been found to be a function of the copper content of the steel for given fluences.

A consequence of a decrease in the toughness properties is a shift in the fracture toughness curve to a higher temperature. Quantitatively, this shift can be assessed by determining the shift to higher temperatures of the initial reference nil ductility temperature RT_{NDT}.

The Nuclear Regulatory Commission (NRC) has also developed copper trend curves for the prediction of RT_{NDT} versus fluence. These curves are presented in Regulatory Guide (RG) 1.99, Revision 2 (Reference 5). RG 1.99 curves predict RT_{NDT} shift as a function of nickel content as well as copper content.

The fracture toughness curve, indexed to $T - RT_{NDT}$, therefore, will shift along the abscissa by a value equal to ΔRT_{NDT} for a given level of irradiation and copper and nickel content as indicated by the copper trend curves. The RT_{NDT} values at the end of life (EOL) differ sufficiently for the locations, so different reference fracture toughness curves are required.

The fluence drops drastically at a short longitudinal distance beyond the vicinity of the core assemblies as illustrated by Figure 5.9-3. For instance, the nozzles are located more than 30 inches above the top level of the core assembly. The curve in Figure 5.9-3 shows that the fluence is about 0.6 percent of the peak fluence value. This is a typical curve, and not meant to represent IP3 specifically. Thus, the irradiation effects at the nozzle areas become insignificant due to the nozzle locations relative to the core.

The upper head and lower head junctions are located still farther from the core ensuring that there will be no significant irradiation effect at those locations. Consequently, only the K_{IR} curve of the vessel beltline, which is exposed to the maximum irradiation, has been adjusted to account for the shift in RT_{NDT} resulting from irradiation.

The material properties of the reactor vessel are tabulated in Table 5.9-1 along with the initial RT_{NDT}, predicted EOL RT_{NDT}, and cross section thickness of each critical location. For the beltline region, EOL RT_{PTS} value in Table 5.1-2 of Section 5.1 is used.

5.9.3.4 Acceptance Criteria

The K_I values calculated for the affected regions of the reactor vessel, steam generator and pressurizer were compared with the corresponding material fracture toughness, K_{IR}. Protection against non-ductile failure is then assured if the K_I values are less than or equal to the K_{IR} values.

The expression used to calculate the stress intensity factor was derived for application to a flaw in a flat plate. An axisymmetrical body provides more constraint than a flat plate does. So, the stress intensities calculated by Appendix G (Reference 1) will be higher than the actual values in the reactor vessel and steam generators.

5.9.4 Analysis and Results

Reactor Vessel—The procedures of Appendix G (Reference 1) were applied to 4 critical locations in the reactor vessel: the bottom head to shell junction, the beltline region, the closure-head-to-upper-flange region, and the outlet-nozzle-to-shell-region.

The similar reactor vessel fracture evaluation was used as the baseline for assessing the effects of the SPU. The secondary stresses were adjusted to incorporate the changes described in Section 5.1 for the affected design transients. Since the pressure does not change measurably, the primary stresses are identical to the original analysis results. The reference flaw size was one quarter of the section thickness in all cases, except for the outlet nozzle where a reduced defect size of 1/5t was used. The justification for a 1/5t defect for the nozzle is based on the availability of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw, because of the greater cross-section thickness at the nozzle-shell juncture, this flaw size is negligibly smaller than a 1/4t defect in the other areas of interest.

The combined K_I values for each design transient in Table 5.9-2 are compared with the appropriate EOL K_{IR} curve for the critical locations. Exceptions to this are the plant heatup and cooldown, and ISLH test conditions, which are controlled to be in compliance with Appendix G (Reference 1) margins through the plant *Technical Specifications*. Table 5.9-2 also shows minimum temperature during each transient for the SPU that is conservatively used for the Appendix G calculation.

The results of the analysis are plotted in Figures 5.9-4 through 5.9-7 for the bottom head to shell junction, the beltline region, the closure-head-to-upper flange region and the outlet-nozzle-to-shell region, respectively. Each transient is represented as a point corresponding to the stress intensity factor and the corresponding minimum temperature during that transient.

The fracture integrity evaluation of the IP3 reactor vessel for the SPU is summarized in Table 5.9-3. The results show that the maximum stress intensity factor for the governing transient meets the fracture toughness requirements set by ASME, Section III, Appendix G.

Steam Generator—The procedures of ASME Appendix G (Reference 1) were applied to both primary and secondary side critical components in the steam generators. The Model 44F replacement steam generator fracture mechanics analysis is applicable to the IP3 steam generators. Since hydrostatic tests are the governing transients for the critical steam generator components, those portions of the replacement Model 44F Appendix G evaluations still remain valid for the SPU. Only normal/upset conditions were affected by the SPU, therefore, only the affected normal/upset conditions were evaluated for the critical steam generator components as part of the SPU.

The Model F steam generator stress report was used as the baseline for assessing the effects of the SPU. The primary and secondary stresses were 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°F, so the shell material is always in the upper shelf range of fracture toughness, which is 200 ksi$\sqrt{in.}$, as for the reactor vessel.

The results in Table 5.9-4 show that the maximum stress intensity factor for the SPU is in all cases less than the fracture toughness, so the steam generators meet the requirements of Appendix G (Reference 1).

Pressurizer—For the pressurizer, the Model D Series 84 pressurizer fracture mechanics analysis was used as the baseline for assessing the effects of the IP3 Model 44F pressurizer for the SPU conditions. Since the change in the ΔT_{hot} was minimal and bounded by the original design basis, no analyses were necessary for the pressurizer lower shell and its key components. Only the change in the ΔT_{cold} warranted an analysis of key upper shell components such as the spray nozzle, the safety and relief nozzle, and the upper shell itself.

To take the change in the ΔT_{cold} into account, a scaling factor was derived as discussed in Section 5.7. The K_I values for the spray nozzle and the safety and relief nozzle were modified for the governing transient using this scaling factor. For the remaining pressurizer components, the existing Appendix G evaluation remains valid.

The fracture integrity evaluation of the IP3 pressurizer for the SPU is summarized in Table 5.9-5. The results show that the maximum stress intensity factors for the governing transients meet the fracture toughness requirements of Appendix G (Reference 1).

5.9.5 Conclusions

The fracture integrity evaluations completed for the SPU for the IP3 reactor vessel, steam generators, and pressurizer have shown that these components are in compliance with the fracture integrity design requirements of Appendix G (Reference 1). Such compliance was not originally required by ASME of the reactor vessel because it was manufactured to a code edition that preceded the Summer 1972 Addenda, in which Appendix G first appeared, but IP3 committed to this compliance as a condition for 10CFR50 requirements. The pressurizer and steam generators must comply, and their Appendix G analyses were modified to account for the SPU changes.

5.9.6 References

1. *ASME Boiler and Pressure Vessel Code*, Section III, "Nuclear Power Plant Components," 1998 Edition for Appendix G, The American Society of Mechanical Engineers, New York, NY.

2. *ASME Boiler and Pressure Vessel Code,* "Nuclear Vessels," 1965 Edition, The American Society of Mechanical Engineers, New York, NY.

3. Welding Research Bulletin 175, *PVRC Recommendations on Toughness Requirements for Ferritic Materials*, New York, NY, July 1973.

4. EPRI Report NP-7195R, *Flaw Evaluation Procedures: ASME Section XI*, T. U. Marstan, editor, August 1978.

5. NRC Regulatory Guide 1.99, *Radiation Embrittlement of Reactor Vessel Material,* Rev. 2, May 1988.

Table 5.9-1

IP3 Reactor Vessel Material Data

Location	Cu-Wt (%)	Initial RT_{NDT} (°F)	Predicted End of Life RT_{NDT} (°F)	Cross-Section Thickness (inches)
Closure-Head Flange	N.A.[1]	60[2]	60	9.41
Outlet Nozzle	N.A.[1]	60[2]	60	10.75
Beltline	0.25	65	250[3]	8.63
Bottom Head Segment	N.A.[1]	15	15	8.63

Notes:

1. Not available.
2. Estimated.
3. For the beltline region, EOL RT_{PTS} value in Table 5.1-2 of Section 5.1 is used.

			a,c,e
Table 5.9-2 **Transient Temperature – IP3**			
No.	**Transient**	**Cold Leg Temperature (for beltline and bottom head) (°F)**	**Hot Leg Temperature (for outlet nozzle and top head) (°F)**
1	Heatup		
2	Cooldown		
3	Plant Loading		
4	Plant Unloading		
5	Step-Load Increase		
6	Step-Load Decrease		
7	Large Step-Load Decrease		
8	Loss of Flow		
9	Steady-State Fluctuations		
10	Loss of Load		
11	Reactor Trip		
12	Cold Hydro		
13	Hot Hydro		

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-3 Fracture Integrity Evaluation Summary IP3 – Reactor Vessel				
Location	**Governing Transient**	**Flaw Depth**	**Flaw Depth (in.)**	**K_I/K_{IR}**
Bottom-Head-to-Shell Junction	Loss of flow	1/4t	2.16	[a,c,e
Beltline Region	Loss of flow	1/4t	2.16	
Closure-Head-to-Upper-Flange Region	Loss of flow	1/4t	2.35	
Outlet-Nozzle-to-Shell Region	Loss of load	1/5t(1)	2.15	]

Note:

1. The justification for a 1/5t defect for the nozzle is based on the use of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-4 Fracture Integrity Evaluation Summary for SPU Normal/Upset Transients IP3 – Steam Generators						
Location	Thickness (in.)	Min. Temp. (°F)	RT_{NDT} (°F)	Flaw Depth (in.)	K_I (ksi $\sqrt{in.}$)	K_{IR} (ksi $\sqrt{in.}$)
Tubesheet and Shell Junction	5.22	[	a,c,e	0.6525(1)	[a,c,e	200
Secondary Manway	3.51			0.8775		200
Steam Outlet Nozzle	1.35			0.945(1)		200
Feedwater Nozzle	6.53			0.7256(1)	]	200

Note:

1. The justification for a smaller defect is based on the use of highly reliable non-destructive inspection techniques that ensure capability of detecting such a flaw.

Bracketed [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

Table 5.9-5

Fracture Integrity Evaluation Summary
IP3 – Pressurizer

Location	Governing Transient	Flaw Depth	K_I/K_{IR}
Spray Nozzle (corner region)	[ ]a,c,e	1/4t	[ ]a,c,e
Safety & Relief Nozzle (corner)		0.50	
Upper Shell		0.15	
Lower Head/Support Skirt		1/4t	
Support Lug		1/4t	
Manway (knuckle region)		1/4t	
Valve Support Bracket		0.13	
Surge Nozzle (corner region)		1.42	

Bracketed [ ]a,c,e information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report.

a,c,e

Figure 5.9-1

M_m and M_b versus $\sqrt{\text{Thickness}}$ Curves

a,c,e

[ ]

Figure 5.9-2

K_{IR} Reference Stress Intensity Factor Curve

a,c,e

Figure 5.9-3

Longitudinal Distance vs. Multiplying Factor for Peak Fluence

a,c,e

Figure 5.9-4

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Bottom-Head-to-Shell Junction (RT_{NDT} = +15°F)

a,c,e

Figure 5.9-5

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Beltline Region (RT_{NDT} = +250°F)

a,c,e

Figure 5.9-6

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Closure-Head-to-Upper-Flange Region (RT_{NDT} = +60°F)

a,c,e

Figure 5.9-7

IP3 Reactor Vessel – Adjusted K_{IR} Curve for Outlet Nozzle-to-Shell Region (RT_{NDT} = +60°F)

5.10 Reactor Coolant System Potential Material Degradation Assessment

This section summarizes the evaluations and results of an assessment of the potential materials degradation issues arising from the effects of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) on the performance of primary component materials.

The primary concern from the proposed SPU is the potential effect of changes in the Reactor Coolant System (RCS) chemistry (impurities) and pH conditions and the SPU service temperatures on the integrity of primary 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. These issues are discussed in the following subsections.

5.10.1 Proposed SPU Service Conditions

A review of the SPU design documents indicates that the following changes in the RCS chemistry and service conditions will occur during operations after the SPU implementation:

- The reactor coolant Li/B program is coordinated such that a pH value of 7.04 is maintained during the fuel cycle with a maximum lithium level of 3.5 ppm.
- The maximum increase in the upper reactor vessel head penetration (RVHP) temperature due to the SPU is estimated at 5.3°F (Table 5.10-1).
- The maximum increase in the hot-leg nozzle temperature due to the SPU is estimated at 2.2°F (Table 5.10-1).

5.10.2 Materials Assessment

The effect of the proposed service conditions on the performance of RCS materials is considered below:

Austenitic Stainless Steels

The two degradation mechanisms that are operative in austenitic stainless steels are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Susceptible materials, sensitized microstructure, 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 the SPU 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 SPU.

Fuel-Cladding Corrosion Effects

An examination of the proposed lithium, boron, and pH management program showed that the program adequately meets the proposed Electric Power Research Institute (EPRI) chemistry guidelines (Reference 1). Since these guide lines 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. Experience with operating plants as well as with the guidelines provided by EPRI (Reference 1) suggest that increasing initial Li concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values ranging from 6.9 to 7.4 has not produced any undesirable material integrity issues and is considered acceptable. IP3 plans to maintain Lithium levels at 3.5 ppm or less. Therefore, there will be no adverse effects from this aspect of the SPU.

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 (RVHPs) and the hot-leg nozzle welds. These are considered below.

The Alloy 600 PWSCC susceptibility is a thermally activated process. The PWSCC susceptibility (S) (Reference 2) is given by:

$$S = A(Fyk)^4 \exp(-Q/RT)$$

where A is the material constant

$(Fyk)^4$ is the stress factor

Fy being the yield strength

and k the residual stress factor

Q is the activation energy of the PWSCC process (~50,000 cals/mole)

R the gas constant 1.103 cal/°R

T the temperature in °R

For the current situation, since the only variable due to uprating is the component service temperature, the susceptibility (S) can be expressed as:

$$S = B \exp(-Q/RT), \text{ B being a constant}$$

The change in the PWSCC susceptibility (ΔS) due to a change in the service temperature (ΔT) can be obtained by taking a differential and is given by:

$$\Delta S = B \exp(-Q/RT)\,(Q/RT^2)\,\Delta T$$

$$\text{or } \Delta S/S = (Q/RT^2)\,\Delta T$$

This change will only be experienced going forward in time. As such, the total susceptibility to PWSCC will be related to the integrated time-temperature history. A methodology has been proposed by the NRC in Order EA-03-009 (Reference 3) for calculating the integrated effect of changing times and temperatures and normalizing the data to a common reference temperature. This methodology calculates a term called Effective Degradation Years (EDY) to account for temperature changes during the current operating lifetime.

5.10.3 Service Temperature Data

A summary of service temperatures at component locations of interest for various design basis cases is provided in Table 5.10-1. The first two lines of Table 5.10-1 provide the calculated upper head temperature and hot-leg nozzle temperatures for a core power level of 3067 MWt. The last two lines of Table 5.10-1 provide the calculated upper head temperature and hot-leg nozzle temperatures for the SPU conditions and cases discussed in Section 2 of this report. See the notes on Table 5.10-1 for details of the cases for each temperature value. The maximum increases in service temperatures (ΔT) at the bounding RVHP and hot-leg outlet nozzle weld locations are provided in Table 5.10-1.

5.10.4 Change in the PWSCC Susceptibility of RVHPs

The industry experience over the past decade showed that the PWSCC susceptibility of the Alloy 600/82/182 outermost 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 maximum change in the PWSCC susceptibility value (ΔS) of the highest susceptible (outer circle) penetration was assessed from the maximum change in the penetration temperature (ΔT_{max}) due to the SPU. This value was established from the data in Table 5.10-1 to be 5.3°F or 5.3°R.

From the equation above:

$$\Delta S/S = Q/(RT^2)\ (\Delta T°R) = (50000/(1.103*1052.47^2)*5.3 = 22\%$$

$\Delta S/S$ being the fractional change in the PWSCC susceptibility, and ΔT, the change in the service temperature in units of Rankine.

On this basis, an increase in the PWSCC susceptibility of 22 percent was estimated for the RVHP as a result of the SPU. This change would be recognized going forward in time. The relative increased risk going forward can be evaluated by integrating the time-temperature history and comparing that value to an integrated history if no change were made.

5.10.5 Change in the PWSCC Susceptibility of Alloy 82/182 Hot-Leg Nozzle Weld

The maximum change in the hot-leg nozzle weld PWSCC susceptibility due to the SPU was assessed from the data in Table 5.10-1 to be 2.2°F (2.2°R).

The change in the PWSCC susceptibility value (ΔS) of the highest susceptible hot-leg nozzle weld was assessed from the change in the RV outlet nozzle temperature ΔT due to uprating, from the above equation:

$$\Delta S/S = Q/(RT^2)\ (\Delta T°R) = (50000/(1.103*1062.67^2)(2.2) = 9\%$$

$\Delta S/S$ being the fractional change in the PWSCC susceptibility, and ΔT, the change in the service temperature in units of Rankine.

On this basis, an increase in the PWSCC susceptibility of 9 percent was estimated for the RV hot-leg nozzle weld as a result of the SPU. This change would be recognized going forward in time. The relative increased risk going forward can be evaluated by integrating the time-temperature history and comparing that value to an integrated history if no change were made.

5.10.6 Conclusions

An assessment of the potential materials degradation issues resulting from the SPU at IP3 concluded that:

- No appreciable material degradation issues were identified with the internal and core support materials due to the SPU at IP3. The lithium concentration will be limited to 3.5 ppm.
- The PWSCC susceptibility of the highest susceptible Alloy 600 control rod drive mechanism (CRDM) penetration was calculated to increase by an estimated 22 percent going forward in time. The rate of damage accumulation leading to PWSCC initiation will slowly increase after the change is made.
- The PWSCC susceptibility of the Alloy 82/182 hot-leg nozzle weld was calculated to increase by 9 percent due to the SPU going forward in time.

The increase in PWSCC susceptibilities of Alloy 600 RVHP and hot-leg nozzle weld locations (22 and 9 percent) indicated above is not considered significant since the absolute susceptibility of these locations is estimated to be very low ($\sim 10^{-11}$).

5.10.7 References

1. EPRI TR-1002884, *Pressurized Water Reactor Primary Water Chemistry Guidelines*, Rev. 5, September 2003.
2. *Methodologies to Assess PWSCC Susceptibility of Primary Component Alloy 600 Locations in PWRs*, Proceedings of the 6th International Symposium on Environmental Degradation of Materials, G. V. Rao, NACE, August, 1993.
3. NRC Order EA-03-009 – Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors, Feb. 2003.

Table 5.10-1

Summary of Change in the Vessel Upper Head and Hot Leg Nozzle Service Temperatures due to the SPU

Core Power Level (MWt)	Location	Lower-Bound Temperature (°F)	Upper-Bound Temperature (°F)	Maximum Increase in Temperature (ΔT°F)[2]
3067	RV Upper Head	NA[1]	587.6	[redacted]
3216	RV Upper Head	570.2	592.9	[redacted]
Temperature Change		-17.4[2]	5.3°F	5.3°F
3067	Hot-Leg Nozzle	NA[1]	600.8	[redacted]
3216	Hot-Leg Nozzle	580.8	603.0	[redacted]
Temperature Change		-20[2]	2.2°F	2.2°F

Notes:

1. Lower bound temperatures and maximum Increases in temperature are not applicable (NA) at 3067 MWt. (IP3 did not have a T_{avg} design range prior to the SPU.)
2. The lower bound SPU temperatures relative to the pre-SPU design condition represent a decrease in susceptibility.

6.0 SAFETY ANALYSIS

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) includes safety analyses for the *Updated Final Safety Analysis Report* (UFSAR) transients and accidents at SPU conditions. This section includes the evaluation of initial condition uncertainties at SPU conditions, which are provided as input to the safety analyses. The results of the safety analyses and setpoint calculations identified whether any changes are required to the Reactor Trip System (RTS)/ Engineered Safety Feature Actuation System (ESFAS) setpoints. The RTS/ESFAS setpoint calculations are addressed in Section 6.10 of this report.

In addition to initial condition uncertainties and RTS/ESFAS setpoint changes, the following safety analyses at SPU conditions are also addressed in this section:

- Loss-of-coolant-accidents (LOCAs)
- Non-LOCA
- Steam generator tube rupture (SGTR) transients
- LOCA containment integrity
- Main steamline break (MSLB) inside and outside containment
- LOCA hydraulic forces
- Anticipated transients without scram (ATWS)
- Natural circulation cooldown capability
- Radiological assessments

The analyses and evaluations presented in this section support operation of IP3 at an uprated core power of 3216 MWt.

6.1 Initial Condition Uncertainties

6.1.1 Introduction

Initial condition uncertainties are conservative steady-state instrumentation measurement uncertainties that are applied to nominal parameter values to obtain conservative initial conditions for use in safety analyses. The initial condition uncertainties were recalculated at SPU conditions for use in the Indian Point Unit 3 (IP3) stretch power uprate (SPU) analyses and evaluations to assess the acceptability of the safety analyses at SPU conditions. The initial condition uncertainties for the SPU conditions were provided as input to the loss-of-coolant accident (LOCA) analysis (Section 6.2 of this report), non-LOCA analysis (Section 6.3), steam generator tube rupture (SGTR) analysis (Section 6.4), LOCA containment integrity analysis (Section 6.5), main steamline break (MSLB) inside and outside containment analysis (Section 6.6), LOCA hydraulic forces analysis (Section 6.7), and core thermal-hydraulic design analysis (Section 7.2).

6.1.2 Input Parameters and Assumptions

The uncertainty calculations for the IP3 SPU were performed for the SPU operating conditions based on the plant-specific instrumentation and plant calibration and calorimetric procedures.

6.1.3 Description of Analyses and Evaluations

The uncertainty analysis uses the square-root-sum-of-the-squares (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. Those uncertainties that are not independent are arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The methodology used for the IP3 SPU is defined in WCAP-16099-P (Reference 1).

Initial condition uncertainties were evaluated and recalculated as appropriate for the following six parameters that are explicitly modeled in the IP3 safety analyses:

- Pressurizer Pressure Control - Automatic pressurizer pressure control system (not affected by the SPU)
- RCS T_{avg} Control - Automatic reactor temperature control system
- Reactor Power Measurement - Daily calorimetric power measurement (rated thermal power [RTP])

- Reactor Coolant System (RCS) Total Flow Measurement – Loop RCS flow measurements based on a normalization to the once-per-fuel-cycle calorimetric RCS flow measurement to verify analysis flow assumptions

- Steam Generator Water Level Control - Automatic steam generator water level control system

- Pressurizer Water Level Control - Automatic pressurizer water level control system

To support the start of analyses and/or evaluations for safety analyses early in the IP3 SPU, preliminary initial condition uncertainties for power uprate were provided as input to safety analyses and evaluations. The initial condition uncertainties for the SPU were then calculated and finalized at a later time during the project, and confirmed to be bounded by the preliminary values. Therefore, although various safety analyses and evaluations may incorporate the preliminary initial condition uncertainties, those allowances are bounding compared to the calculated final values.

6.1.4 Acceptance Criteria and Results

The acceptance criterion for the initial condition uncertainties is that the final calculated values must be bounded by the allowances incorporated in the safety analyses.

The results of the initial condition uncertainty analysis for the IP3 SPU are summarized in Table 6.1-1 along with the allowances incorporated in the safety analyses. Pressurizer pressure control and pressurizer water level control are included for completeness, although pressurizer pressure control was not affected and pressurizer water level control was minimally affected by the IP3 SPU. With the exception of RCS T_{avg} control, this table demonstrates that the safety analyses incorporate uncertainties that are equal to or greater than the final calculated values. Safety analyses that use the RCS T_{avg} control uncertainty were modified to account for the larger final calculated value. The uncertainty calculations for steam generator water level control included the resolution of the generic steam generator level uncertainty issues (References 2 through 5), which are unrelated to the power uprate.

6.1.5 Conclusions

Preliminary initial condition uncertainties were determined for the IP3 SPU conditions and were provided as input to the safety analyses and evaluations. Final initial condition uncertainties were calculated and either confirmed to be bounded by the preliminary initial condition uncertainties, or the affected safety analyses were modified to account for the more conservative final initial condition uncertainty value.

6.1.6 References

1. WCAP-16099-P, *Westinghouse Revised Thermal Design Procedure Instrument Uncertainty Methodology Indian Point Unit 3 (Power Uprate to 3216 MWt – Core Power),* Rev. 0.

2. NSAL-02-03, *Steam Generator Mid-deck Plate Pressure Loss Issue,* Rev. 1, April 2002.

3. NSAL-02-04, *Maximum Reliable Indicated Steam Generator Water Level,* Rev. 0, February 2002.

4. NSAL-02-05, *Steam Generator Water Level Control System Uncertainty Issue,* Rev. 1, April 2002.

5. NSAL-03-09, *Steam Generator Water Level Uncertainties,* Rev. 0, September 2003.

Table 6.1-1 IP3 SPU Summary of Initial Condition Uncertainties		
Parameter	Limiting Analysis Initial Condition Uncertainties(1)	Calculated Final Initial Condition Uncertainties(1)
Pressurizer Pressure Control(2)	±60.0 psi (random)	a,c,e
RCS T_{avg} Control(5)	±6.0°F (random) -1.0°F (bias)	
Reactor Power Measurement	±2.0% RTP (random)	
RCS Total Flow Measurement	±2.9% Flow (random)	
Steam Generator Water Level Control	±10.0% span (random)	
Pressurizer Water Level Control High(2)	±8.5% span (random)	

Notes:

1. A negative bias means the channel indicates lower than actual, and a positive bias means the channel indicates higher than actual.
2. Parameter included, although uncertainty not affected by the SPU.
3. Based on use of Caldon leading edge flow meter (LEFM).
4. Based on use of feedwater venturis.
5. The following analyses have accounted for the more conservative RCS T_{avg} control calculated final initial condition uncertainty:
   - Large-break LOCA (LBLOCA) (best-estimate) analysis
   - LBLOCA hydraulic forces analysis
   - Small-break LOCA (SBLOCA) analysis
   - Non-LOCA analyses
   - Steam-line break inside and outside containment M&E releases analyses
   - Thermal-hydraulic analysis
   - Containment integrity for LBLOCA analysis
   - Pressurizer pressure control sizing analysis
   - Radiological analysis

Backeted [ ]^{a,c,e} information designates data that is Westinghouse Proprietary, as discussed in Section 1.6 of this report

6.2 Loss-of-Coolant Transients

6.2.1 Best-Estimate Large-Break Loss-of-Coolant-Accident

6.2.1.1 Introduction

Westinghouse has obtained generic NRC approval of its topical report describing best-estimate large-break loss-of-coolant accident (BELBLOCA) methodology. NRC approval of the methodology is documented in the NRC *Safety Evaluation Report* (SER) appended to the topical report (Reference 1). Plant-specific analysis for Indian Point Unit 3 (IP3) was previously performed using the approved methodology.

A BELOCA re-analysis has been performed at the analyzed stretch power uprate (SPU) core power conditions (3216 MWt). The values of major plant parameters assumed in the BELOCA analysis will be documented in the respective sections of the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 2). These and other UFSAR changes resulting from approval of this *Licensing Amendment Report* (LAR) will be made in accordance with 10CFR50.71(e) (Reference 3).

Both Entergy and its analysis vendor (Westinghouse) have ongoing processes (updated *Technical Specifications*, plant operating ranges table in the UFSAR, core operating limits report), which assure that the values and ranges of the BELBLOCA analysis inputs for peak cladding temperature (PCT)-sensitive parameters bound the values and ranges of the as-operated plant for those parameters.

6.2.1.2 Acceptance Criteria

The criteria for acceptability for LOCAs are found in 10CFR50.46(b) (Reference 4). The criteria require that there is a high probability that:

1. PCT: The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. Long-Term Cooling: After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

6.2.1.3 Technical Analysis

The BELBLOCA re-analysis has been performed for IP3 using the methodology contained in WCAP-12945-P-A (Reference 1). All plant-specific parameters used in the analysis are bounded by the models and correlations contained in the generic methodology. Therefore, the IP3 re-analysis conforms to 10CFR50.46 (Reference 4) and Section II of Appendix K (Reference 5), and meets the intent of Regulatory Guide (RG) 1.157 (Reference 6). The conclusions of the re-analysis are that there is a high level of probability that:

- The calculated maximum fuel element cladding temperature (peak cladding temperature) will not exceed 2200°F.

- The calculated total oxidation of the cladding (maximum cladding oxidation) will not exceed 0.17 times the total cladding thickness before oxidation.

- The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam (maximum hydrogen generation) will nowhere exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

- The calculated changes in core geometry are such that the core remains amenable to cooling.

- After successful initial operation of the Emergency Core Cooling System (ECCS), the core temperature will be maintained at an acceptably low value and decay heat will be removed for the extended period of time required by the long-lived radioactivity remaining in the core. The post-LOCA long-term cooling aspects are discussed in subsection 6.2.4.

Table 6.2-1 presents the 95th percentile peak clad temperature (PCT), maximum cladding oxidation, maximum hydrogen generation, and cooling results for IP3.

Therefore, Entergy has concluded that the BELBLOCA analysis for IP3 at the SPU conditions would not adversely affect the health and safety of the public.

6.2.2 Small-Break Loss-of-Coolant Accident

6.2.2.1 Introduction

A small-break loss-of-coolant accident (SBLOCA) analysis was performed to support the SPU for IP3. The analysis was performed to demonstrate conformance with the 10CFR50.46 requirements (Reference 4) for the conditions associated with the SPU and to explicitly include modeling of items for which the Analysis of Record (AOR) had PCT assessments applied. The approved Westinghouse SBLOCA Evaluation Model (EM) was used for this analysis (References 7 and 8). The SBLOCA EM update that has been approved by the NRC (References 7 and 8) has been used in this analysis, including the COSI condensation model and safety injection (SI) in the broken loop (Reference 9).

6.2.2.2 Input Assumptions and Initial Conditions

6.2.2.2.1 Assumptions

All of the assumptions required by Appendix K to 10CFR50 (Reference 5) have been made in the IP3 SBLOCA analysis. This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of full power as the initial condition for the SBLOCA. Other Appendix K assumptions include, but are not limited to, all peaking factors simultaneously at their most limiting values, Baker-Just zirconium-water reaction rate, 120 percent of 1971 American Nuclear Society (ANS) infinite life decay heat, and Moody break flow during periods when two-phase flow is calculated to occur at the break.

Among the major assumptions inherent in the Westinghouse Appendix K SBLOCA EM are:

- Break area is <1 ft^2.
- SBLOCA initiates at hot full power (HFP) (Mode 1).
- All rod cluster control assemblies (RCCAs), except the single most reactive, insert following reactor trip.

- Loss-of-offsite power (LOOP) assumed at reactor trip time results in the following assumptions:
  - Loss of one emergency diesel generator (EDG) and subsequent loss of one train of pumped ECCS
  - Reactor coolant pump (RCP) trip and coastdown
  - Main steam line isolation (no steam dump capability)
- Standard four-loop ECCS spilling assumptions

A spectrum of 3 break sizes, including diameters of 2, 3, and 4 inches, was analyzed.

6.2.2.3 Description of Methodology/Analysis

6.2.2.3.1 Description of SBLOCA Engineering Methodology and Codes

The small-break analysis was performed with the Westinghouse ECCS EM using NOTRUMP (References 7 and 8), including changes to the model and methodology as described in Reference 9. The NOTRUMP EM includes the following computer codes:

NOTRUMP: Thermal-hydraulic response of Reactor Coolant System (RCS) during transient

SBLOCTA: Fuel rod/cladding heat-up during transient

6.2.2.3.2 Description of Analysis Performed for SBLOCA

The methodology first calculated the system thermal-hydraulic response to the SBLOCA event using the NOTRUMP code. These results are then analyzed for their effect on the hot rod heat up using the SBLOCTA code to demonstrate that the PCT, cladding oxidation, and hydrogen generation are below their limiting values as defined by 10CFR50.46 (Reference 4).

6.2.2.3.3 Limiting SBLOCA Sequence

The analysis consists of a break spectrum using the approved methodology as documented in References 7 and 8 and extended in Reference 9. For the IP3 SBLOCA analysis, a three-break spectrum (2-, 3-, and 4-inch) has been analyzed to confirm that the 3-inch break is limiting. The results are presented in Tables 6.2-2 and 6.2-3.

6.2.2.4 Design Basis Acceptance Criteria

The criteria for acceptability for LOCAs are found in 10CFR50.46(b) (Reference 4) and are quoted below:

1. PCT: The calculated maximum fuel element cladding temperature shall not exceed 2200°F.

2. Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

3. Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

4. Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

5. Long-Term Cooling: After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

6.2.2.5 Results and Conclusions

6.2.2.5.1 Description of Limiting 3-Inch Break Case

For the limiting 3-inch break, the primary side pressure begins a rapid drop at the time of break initiation (Figure 6.2-1). A reactor trip signal is generated at 22.8 seconds, followed by a SI signal at 30.2 seconds. This primary side depressurization is checked when the primary side saturation temperature reaches the secondary side saturation temperature, since the steam generators provide the predominant energy release path during this portion of the transient. When the loop seal in the broken loop clears at approximately 582 seconds, a vapor vent path is created between the top of the core and the break in the cold leg.

At break initiation, the core mixture level (Figure 6.2-2) drops rapidly until it reaches the elevation at the top of the hot legs. The rate of core level draining is then slowed as vapor is now allowed to enter the hot legs or the inner vessel due to the loop seal clearing. When the core mixture level decreases below the bottom of the hot legs, the mixture level again

decreases until loop seal clearing occurs (Figure 6.2-2). After loop seal clearing, the core and downcomer come into a manometric balance as the downcomer level falls in response to the adjacent cold legs draining.

The core mixture level continues to decrease until the top of the core uncovers at 765 seconds, leading to the start of clad heat up. As illustrated in Figure 6.2-3, the SI flow rate continues to increase as the RCS pressure decreases (Figure 6.2-1). The SI replenishes the core level, which results in a reversal in the clad heat up transient. The PCT of 1543°F occurs at 1954 seconds (Figure 6.2-4), followed by a steady increase in the core mixture level. The accumulators inject at 1688 seconds. The transient core exit steam flow has been presented in Figure 6.2-5. The results of the 3-inch break case are presented in Tables 6.2-2 and 6.2-3.

6.2.2.5.2 Non-Limiting Results

The results of the 2- and 4-inch break cases are presented in Tables 6.2-2 and 6.2-3. Figures 6.2-6 through 6.2-11 pertain to the 2-inch and 4-inch break cases. The figures provided for the non-limiting cases are:

- Figure 6.2-6 – 2-Inch Break, Pressurizer Pressure
- Figure 6.2-7 – 2-Inch Break, Core Mixture Level
- Figure 6.2-8 – 2-Inch Break, PCT at PCT Elevation (11.5 ft)
- Figure 6.2-9 – 4-Inch Break, Pressurizer Pressure
- Figure 6.2-10 – 4-Inch Break, Core Mixture Level
- Figure 6.2-11 – 4-Inch Break, PCT at PCT Elevation (11.25 ft)

6.2.2.5.3 10CFR50.46 PCT Report Item Incorporation

As a result of this analysis, all items from the IP3 10CFR50.46 (Reference 4) PCT report are eliminated. This was accomplished by using the latest version of the NOTRUMP EM codes and incorporating each of the other miscellaneous items into the analysis.

6.2.2.5.4 Maximum Local and Core-Wide Oxidation

All cases meet the 10CFR50.46 requirements of maximum local and core-wide oxidation. The local oxidation of the cladding, does not exceed 17 percent, and the calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam does not exceed 1 percent.

6.2.2.5.5 Conclusions

The results of the analysis show that the acceptance criteria discussed in subsection 6.2.2.4 of this document for the SBLOCA have been met. The limiting PCT for IP3 will be reported as 1543°F, which occurs for the 3-inch break case. Local oxidation of the cladding is less than 17 percent, the core-wide oxidation is less than 1.0 percent and the core geometry remains amenable to cooling. The post-LOCA long-term cooling aspects are discussed in subsection 6.2.4. Results for the 3-inch limiting break case are shown in Figures 6.2-1 through 6.2-5.

6.2.3 Hot Leg Switchover

6.2.3.1 Introduction

A post-LOCA hot leg switchover (HLSO) time is calculated to support emergency operating procedures (EOPs) that require a realignment of the recirculation SI flowpath from the cold legs to the hot legs. This realignment to the hot legs precludes boron precipitation in the reactor vessel following an LBLOCA. At issue are cold-leg breaks where injected SI water boils off due to decay heat, leaving behind boric acid. The concern is the possibility that eventually the boric acid solution in the vessel may reach the boron precipitation point. The Westinghouse ECCS evaluation model relies on the preclusion of boron precipitation as one criterion for ensuring core coolable geometry.

6.2.3.2 Input Parameters and Assumptions

The IP3 HLSO calculation model is based on the following assumptions:

- A boric acid concentration level is computed over time for a core-region mixing volume. Other than the steam exiting through the hot legs and the corresponding makeup SI entering through the lower plenum, there are no other assumed flow paths in or out of the mixing volume. All boric acid entering this mixing volume remains in this mixing volume prior to initiation of hot-leg recirculation. The water/boric acid solution is well mixed in the mixing volume region. The water/boric acid solution in the vessel is assumed to be at atmospheric conditions, at a temperature of 212°F. The collapsed mixture level of the core/upper plenum region is at the bottom of the hot-leg flow area at the reactor vessel. This level is the top of the mixing volume. The bottom of the mixing volume is at the level of the top of the lower core plate. The lower plenum volume, and barrel-baffle region volume are not included in the mixing volume.

- The boric acid concentration limit is the experimentally determined boric acid saturation concentration with a 4 weight-percent uncertainty factor. There is no allowance for increase in boric acid solubility due to other solutes such as sodium hydroxide. The calculation neglects any elevation of boiling temperature due to concentration of boric acid in the core or due to backpressure from containment.

- The decay heat generation rate is based on the 1971 ANS Standard (Reference 10) for infinite operating time plus 20-percent margin. The decay heat generation includes a core power multiplier to address instrumentation uncertainty as identified by Section I.A of Appendix K (Reference 5).

- The boron concentration of the make-up SI water during recirculation is a calculated sump mixed mean boron concentration. The calculation of the sump mixed mean boron concentration assumes maximum mass and maximum boron concentrations for significant boron sources and minimum mass and maximum boron concentrations for significant dilution sources.

- Once realigned to hot-leg recirculation, the minimum recirculation flows for the hot legs, cold legs, or simultaneous hot- and cold-leg recirculation are confirmed to be sufficient to provide core cooling and preclude boron precipitation.

The methodology described above is consistent with, or otherwise conservative with respect to, the methodology described in Letter CLC-NS-309 (Reference 11).

6.2.3.3 Description of Analyses and Evaluations

The major inputs to the HLSO time calculation include the core power assumptions and boron concentrations and water volume/masses for significant contributors to the containment sump. Since the increase in core power to 3216 MWt effects decay heat, recalculation of the HLSO time and hot-leg recirculation minimum required flows are required. An increase in core power will reduce the HLSO time and increase the hot-leg recirculation minimum required flows.

For the SPU, a new HLSO time was calculated using the input parameters and assumptions described in the previous section, including decay heat based on the 1971 ANS Standard (Reference 10) for infinite operation with 20-percent margin. All inputs to the calculation were reviewed and confirmed to be appropriate for plant operation at the SPU conditions. The uprating calculations used the uprated core power of 3216 MWt with a 1.02-calorimetric uncertainty multiplier to address instrumentation uncertainty.

A revised set of hot-leg recirculation minimum required flows were calculated at the SPU conditions and new HLSO time.

6.2.3.4 Acceptance Criteria and Results

There are no specific acceptance criteria on the new hot-leg switchover time for the SPU conditions as long as the UFSAR (Reference 2) and EOPs are revised appropriately. The available flows at hot-leg switchover time are acceptable if they are shown to be sufficient to provide core cooling.

At the SPU conditions, a new HLSO time of 6.79 hours was calculated. The time of 6.79 hours was rounded down to 6.5 hours for added conservatism. The minimum hot-leg recirculation flows at a HLSO time of 6.5 hours and a power level of 3216 MWt are sufficient to preclude boron from precipitating in the vessel and to ensure adequate core cooling is maintained. As noted in Section 6.12 of this report, the EOPs will be revised to reflect the SPU HLSO time.

6.2.3.5 Conclusions

A HLSO time of 6.5 hours will preclude boron precipitation for post-LOCA scenarios for the SPU conditions. The available ECCS flows at hot-leg switchover were shown to be sufficient to provide core cooling and preclude boron from precipitating in the core.

6.2.4 Post-LOCA Subcriticality and Long-Term Core Cooling

6.2.4.1 Introduction

The post-LOCA subcriticality calculations support evaluations that demonstrate that the core will remain subcritical upon entering the sump recirculation phase of ECCS injection. During the sump recirculation phase, SI flow is drawn from the containment sump following switchover from the refueling water storage tank (RWST). To show that the sump water has sufficient boron concentration, the sump-mixed mean boron concentration is calculated. The mixed-mean boron concentration of the sump water is a function of the various water and boron contributors to the sump prior to start of sump recirculation. The boron concentration of the sump water must be sufficient to keep the core subcritical. The sump mixed-mean boron concentration calculations are used to develop a post-LOCA subcriticality boron limit curve that is confirmed on a cycle-specific basis as part of the *Westinghouse Reload Safety Evaluation Methodology* (Reference 12). Long-term core cooling also requires adequate ECCS flow to provide core cooling during the cold-leg recirculation period.

6.2.4.2 Input Parameters and Assumptions

The sump-mixed mean boron concentration calculation model is based on the following assumptions:

- Boron is mixed uniformly in the sump. The post-LOCA sump inventory is made up of constituents that are equally likely to return to the containment sump, that is, selective holdup in containment is neglected.

- The calculation of the sump mixed-mean boron concentration assumes minimum mass and minimum boron concentrations for significant boron sources, and maximum mass and minimum boron concentration for significant dilution sources.

- The sump mixed-mean boron concentration is calculated as a function of the pre-trip RCS conditions.

The Westinghouse licensing position for satisfying the requirements of 10CFR50.46 (Reference 4) Paragraph (b) Item (5), "Long-Term Cooling," is documented in WCAP-8339 (Reference 13). The Westinghouse position is that the core will remain subcritical post-LOCA by borated water from various injected ECCS water sources. To provide subcriticality when entering sump recirculation, the borated ECCS water provided by the accumulators and RWST must have a sufficiently high boron concentration that, when mixed with other sources of borated and non-borated water, the core will remain subcritical. Consistent with the position in WCAP-8339 (Reference 13), control rods are assumed to be withdrawn from the core.

Long-term core cooling also requires adequate ECCS flow to provide core cooling. For IP3, the confirmation of adequate ECCS flow during the cold-leg recirculation period is based on the following assumptions:

- The current SBLOCA analysis methodology explicitly models ECCS flow enthalpy changes during the switchover from cold-leg injection to cold-leg recirculation.

- The long-term core cooling methodology assumes that large-break ECCS flows are not adversely affected by the switchover from cold-leg injection to cold-leg recirculation.

6.2.4.3 Description of Analyses and Evaluations

Although core power level is not a direct input in the sump mixed-mean boron concentration calculation, the T_{avg} range associated with power uprate conditions will have a minor effect on the RCS fluid masses used in the calculation. Furthermore all of the inputs used in the

calculation were reviewed to confirm consistency with the *Technical Specifications* (Reference 14) and consistency with the assumptions used in the other LOCA analyses being performed for the SPU.

A post-LOCA sump boron concentration curve was developed for the SPU conditions using the input parameters and assumptions described in the previous section.

6.2.4.4 Acceptance Criteria and Results

There are no specific acceptance criteria in generating the post-LOCA sump boron concentration curve. However, the resulting curve, which is calculated as a function of the initial RCS peak Xenon boron concentration, is included in the Reload Safety Analysis Checklist (RSAC) and is verified for each reload cycle to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA. Adequate post-LOCA boron concentration shows that the long-term core cooling criterion is satisfied.

The post-LOCA sump boron concentration was calculated for RCS boron concentrations of 0 and 1500 ppm assuming the pre-trip RCS boron concentration for peak Xenon concentrations to be 100 ppm lower than the equilibrium case. Figure 6.2-12 shows the post-LOCA sump boron concentration curve.

With respect to long-term core cooling, the SBLOCA analysis discussed in subsection 6.2.2 modeled the ECCS flow enthalpy change during the switchover from cold-leg injection to cold-leg recirculation. For LBLOCA, the minimum flows provided by the ECCS for switchover from cold-leg injection to cold-leg recirculation are adequate to provide long-term core cooling.

6.2.4.5 Conclusions

A post-LOCA sump boron concentration curve was developed for the uprated conditions. This curve will be used to evaluate the fuel loading arrangement on a cycle-by-cycle basis during the fuel reload process. Provided that the maximum critical boron concentration remains below the post-LOCA sump boron concentration curve (for all rods out, no Xenon, 68° to 212°F), the core will remain subcritical post-LOCA, and decay heat can be removed for the extended period required by the remaining long-lived radioactivity. ECCS flow during the cold-leg recirculation period is adequate to provide long-term core cooling.

6.2.5 References

1. WCAP 12945-P-A, Volume 1 (Rev. 2) and Volumes 2 through 5 (Rev. 1), *Code Qualification Document for Best Estimate LOCA Analysis*, March 1998.

2. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

3. 10CFR50.71(e), *Maintenance of Records, Making of Reports*, October 4, 1999.

4. 10CFR 50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Reactors*, September 16, 2003.

5. 10CFR.50, Appendix K, ECCS Evaluation Models.

6. Regulatory Guide 1.157 *Best-Estimate Calculations of Emergency Core Cooling System Performance* (Draft RS 701-4 published March 1987).

7. WCAP-10054-P-A, *Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code*, N. Lee, et al., August 1985.

8. WCAP-10079-P-A, *NOTRUMP A Nodal Transient Small Break and General Network Code*, August 1985.

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

10. *Decay Energy Release Rates Following Shutdown of Uranium-Fueled Thermal Reactors*, Approved by Subcommittee ANS-5, ANS Standards Committee, October 1971.

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

12. WCAP-9272-P-A, *Westinghouse Reload Safety Evaluation Methodology*, July 1985.

13. WCAP-8339, Westinghouse *ECCS System Evaluation Model - Summary*, June 1974.

14. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3 Docket No. 50-286 Technical Specifications and Bases.*

Table 6.2-1 IP3 BELBLOCA Results		
	Analysis Value	**Acceptance Criteria**
95th Percentile PCT (°F)*	1944	< 2200
Maximum Cladding Oxidation (%)*	7.60	< 17
Maximum Hydrogen Generation (%)*	0.620	< 1
Coolable Geometry	Core remains coolable	Core remains coolable
Long-Term Cooling	Core remains cool in long term	Core remains cool in long term

Note:

* Calculated using the methodology in the following reference:
WCAP-12945-P-A, Volume 1 (Revision 2) and Volumes 2 through 5 (Revision 1).

Table 6.2-2 NOTRUMP Transient Results			
Event Time (sec)	**2-Inch**	**3-Inch**	**4-Inch**
Break Initiation	0.0	0.0	0.0
Reactor Trip Signal	55.9	22.8	13.0
S-Signal	71.2	30.2	16.1
SI Begins	99.0	58.0	43.9
Loop Seal Clearing*	1251	582	312
Core Uncovery	1738	765	601
Accumulator Injection Begins	N/A	1688	890
Core Recovery	N/A	N/A	2560

* Loop seal clearing is defined as break vapor flow >1 lb/s.

Table 6.2-3 Beginning-of-Life (BOL) Rod Heatup Results			
	2-Inch	**3-Inch**	**4-Inch**
Time-in-Life	BOL	BOL	BOL
PCT (°F)	1182	1543	1380
PCT Time (s)	3518	1954	1053
PCT Elevation (ft)	11.5	11.75	11.25
HR Burst Time (s)	N/A	N/A	N/A
HR Burst Elevation (ft)	N/A	N/A	N/A
Max. Local ZrO_2 (%)	0.12	1.04	0.21
Max. Local ZrO_2 Elev (ft)	11.25	11.75	11.25
Hot Rod Axial Avg. ZrO_2 (%)	<1.0	<1.0	<1.0

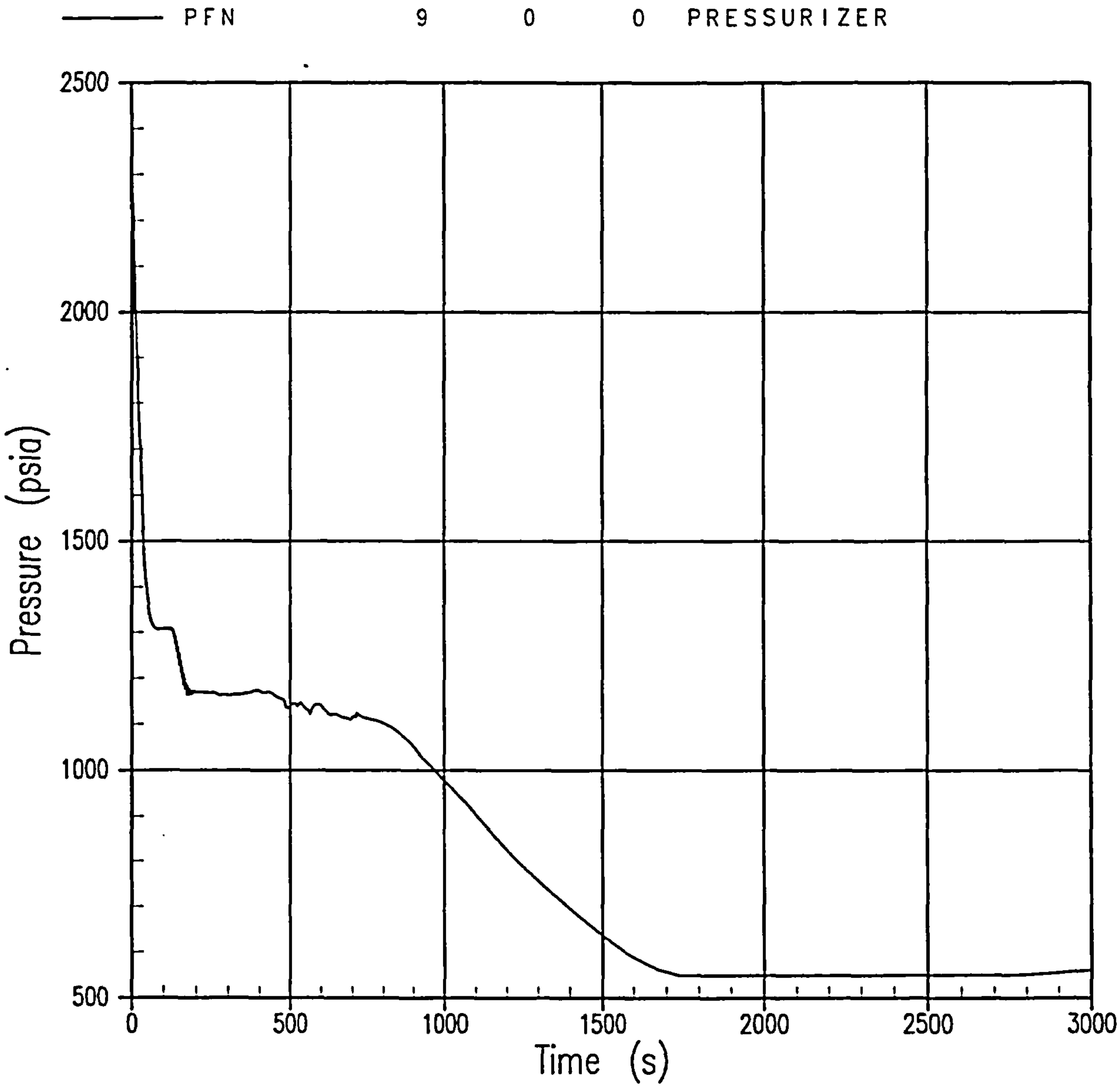

Figure 6.2-1

3-Inch Break Case, Pressurizer Pressure

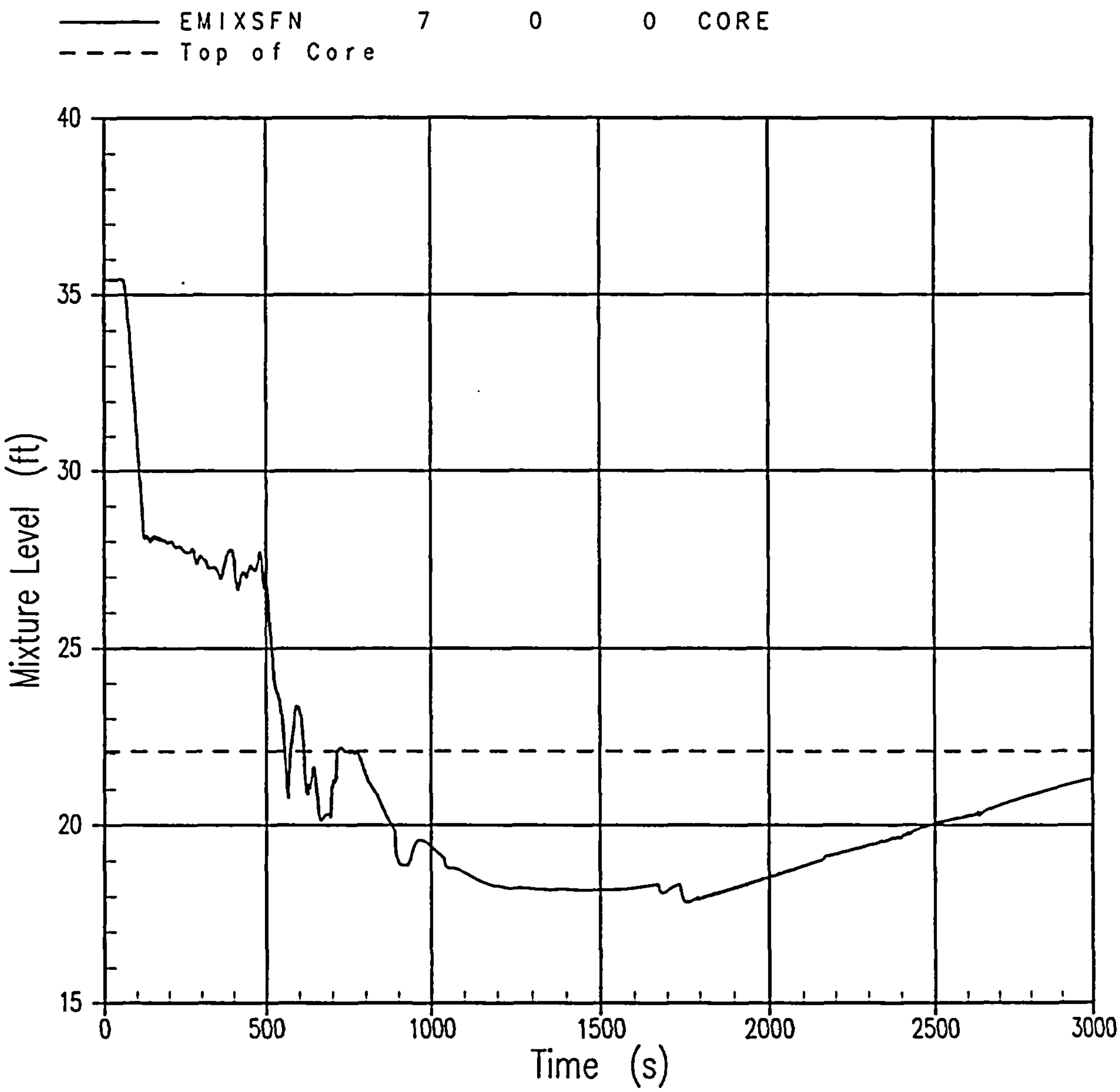

Figure 6.2-2

3-Inch Break Case, Core Mixture Level

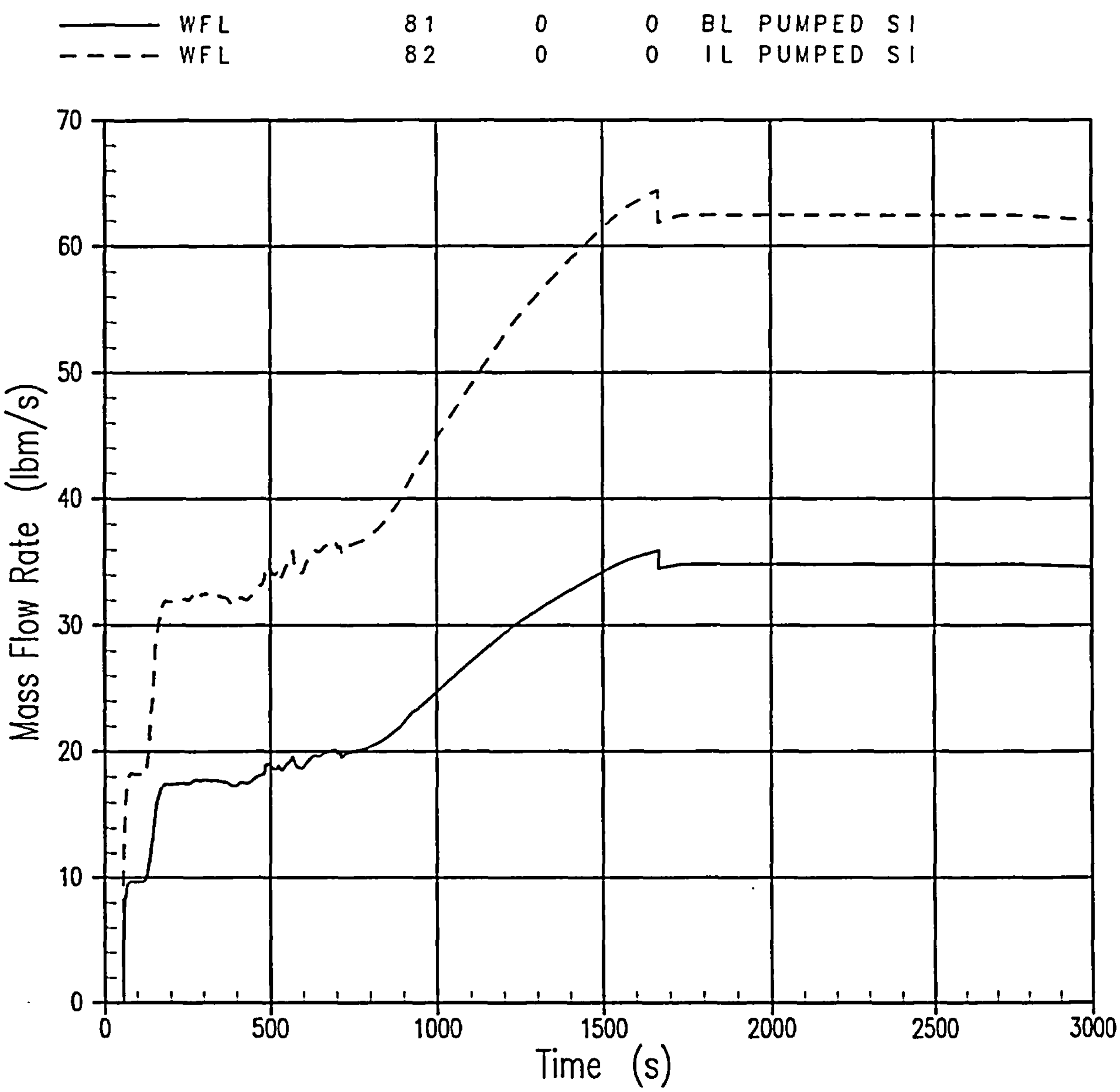

Figure 6.2-3

3-Inch Break Case, Broken Loop, and Intact Loop Pumped SI Flow Rate

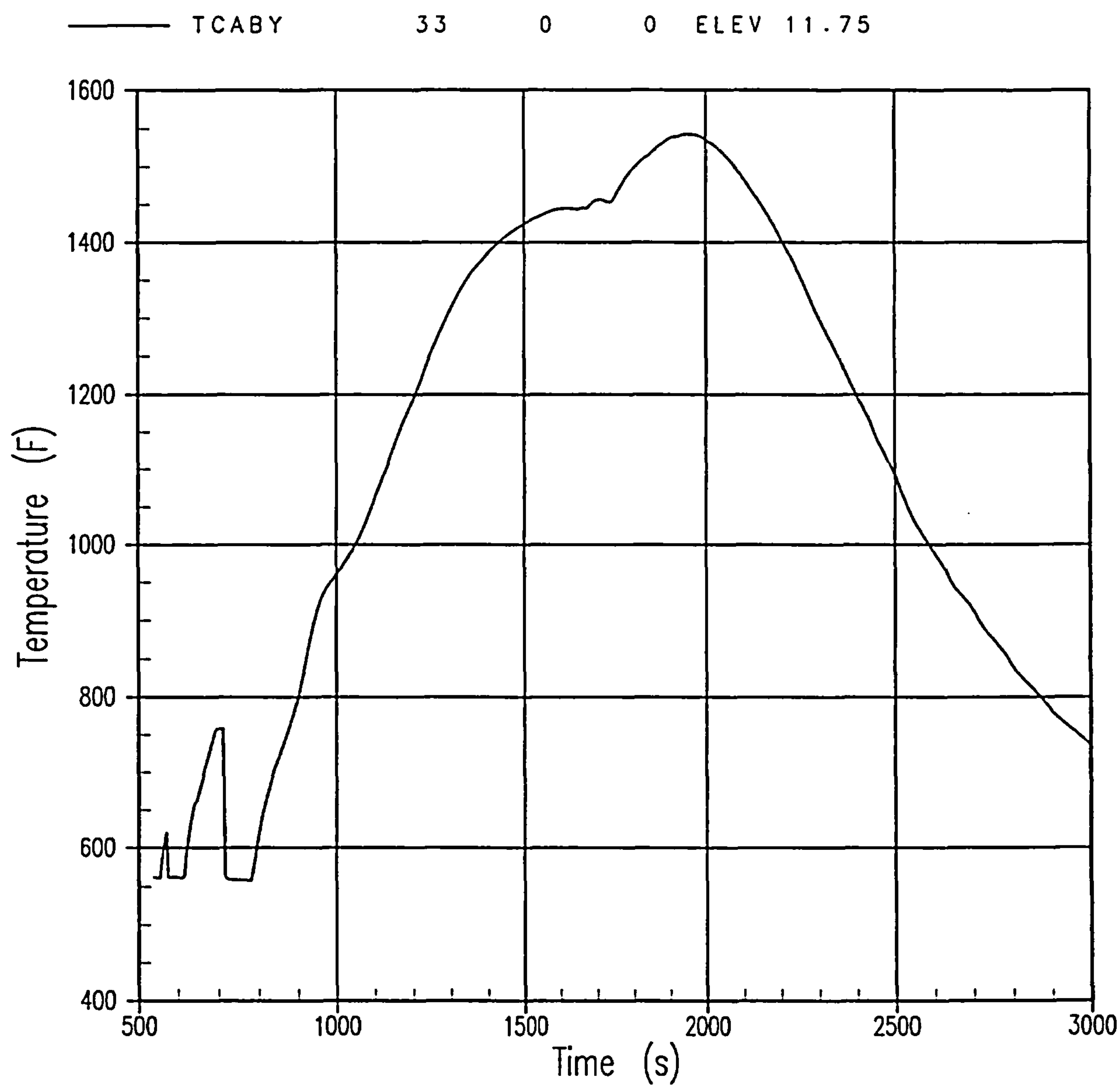

Figure 6.2-4

3-Inch Break Case, PCT at PCT Elevation (11.75 ft)

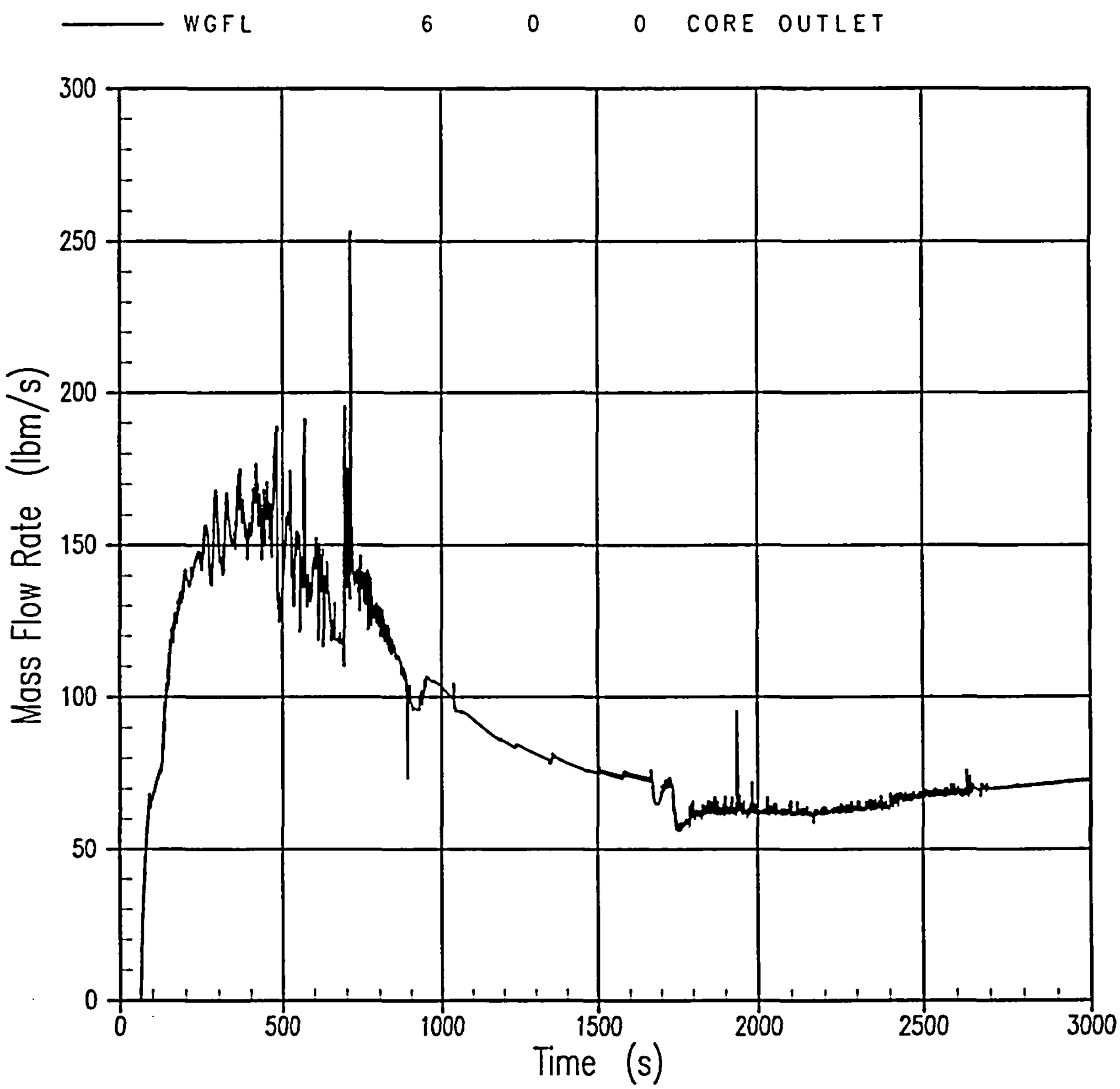

Figure 6.2-5

3-Inch Break Case, Core Exit Steam Flow

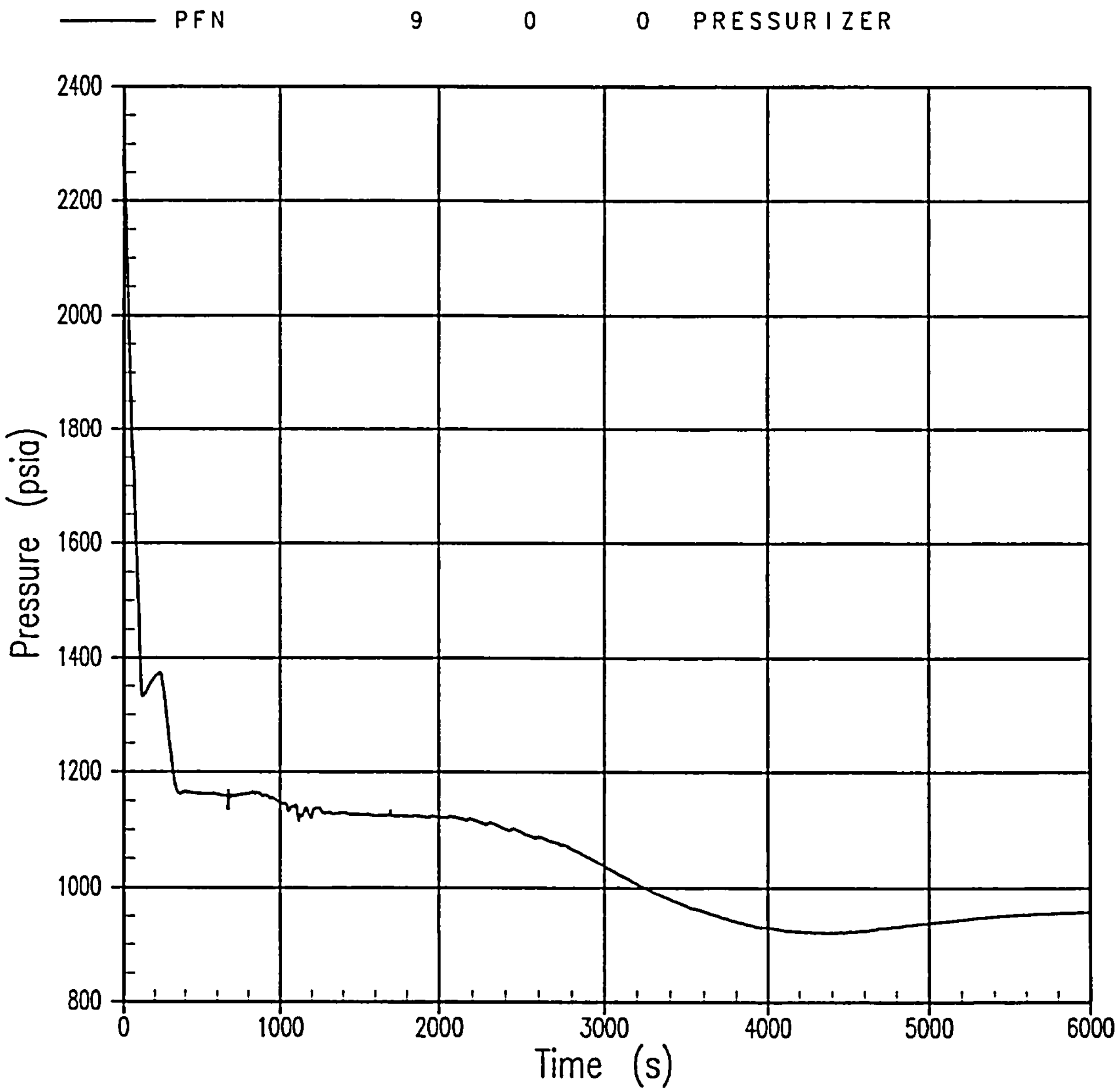

Figure 6.2-6

2-Inch Break, Pressurizer Pressure

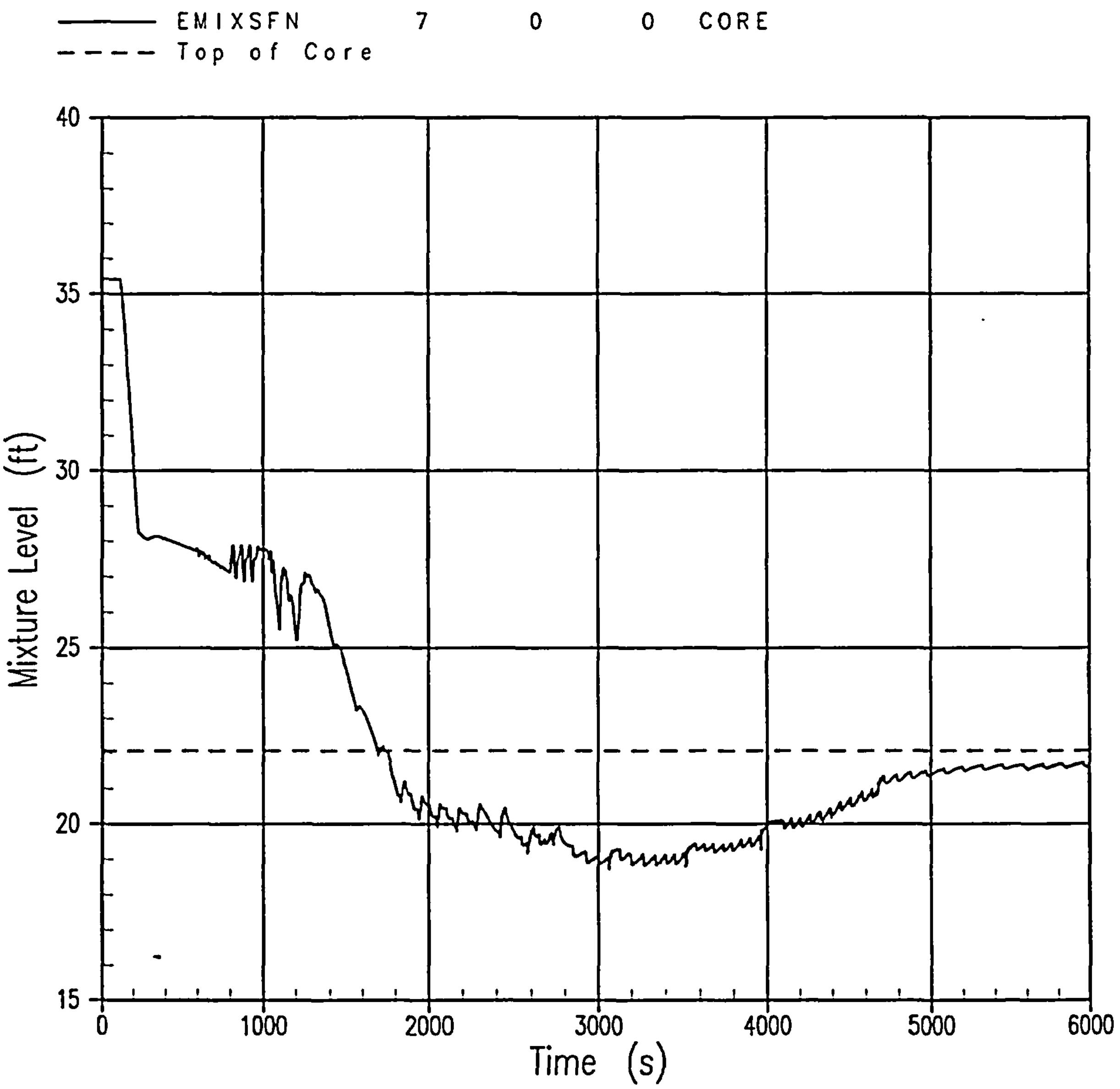

Figure 6.2-7

2-Inch Break, Core Mixture Level

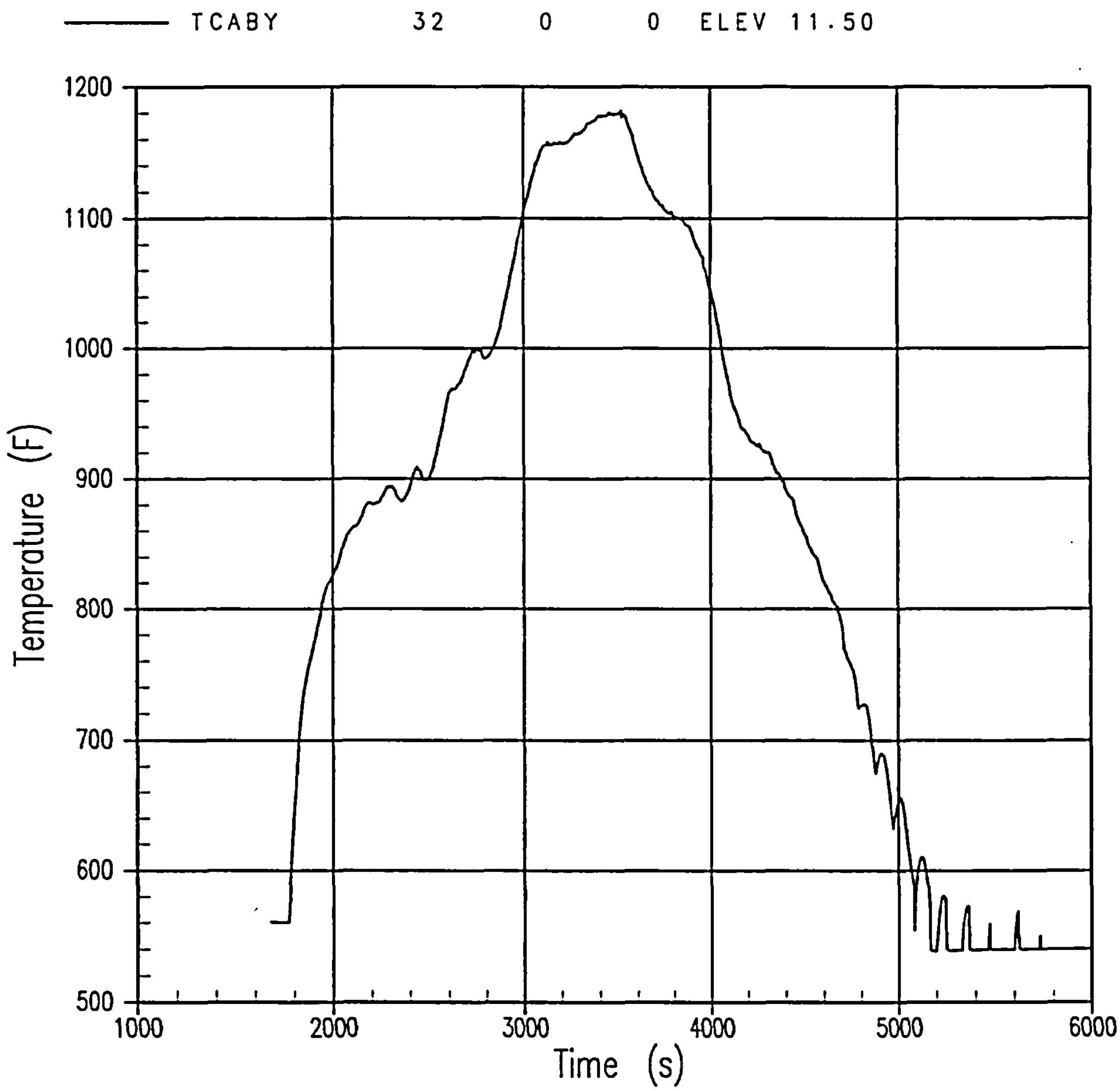

Figure 6.2-8

2-Inch Break, PCT at PCT Elevation (11.5 ft)

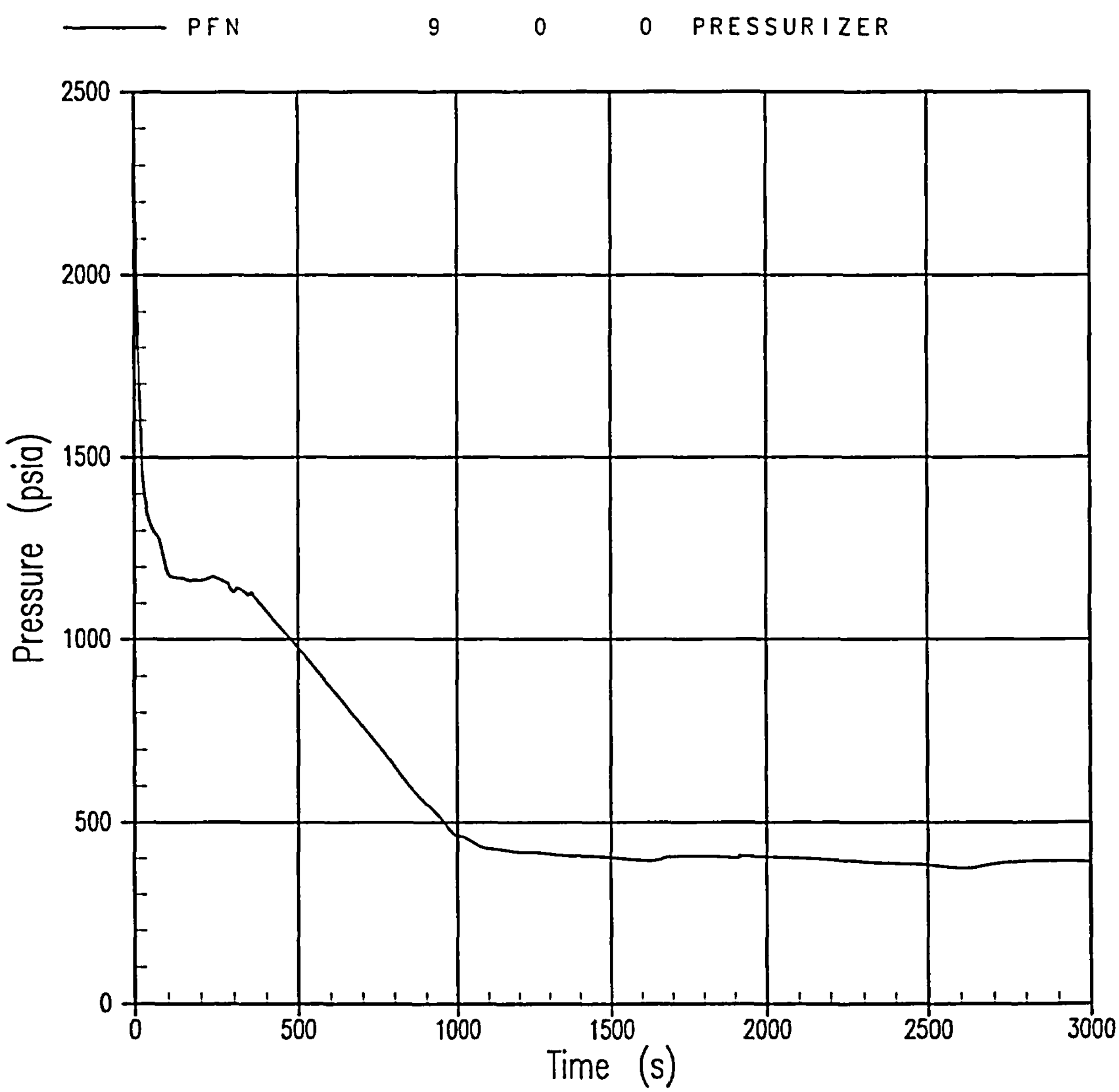

Figure 6.2-9

4-Inch Break, Pressurizer Pressure

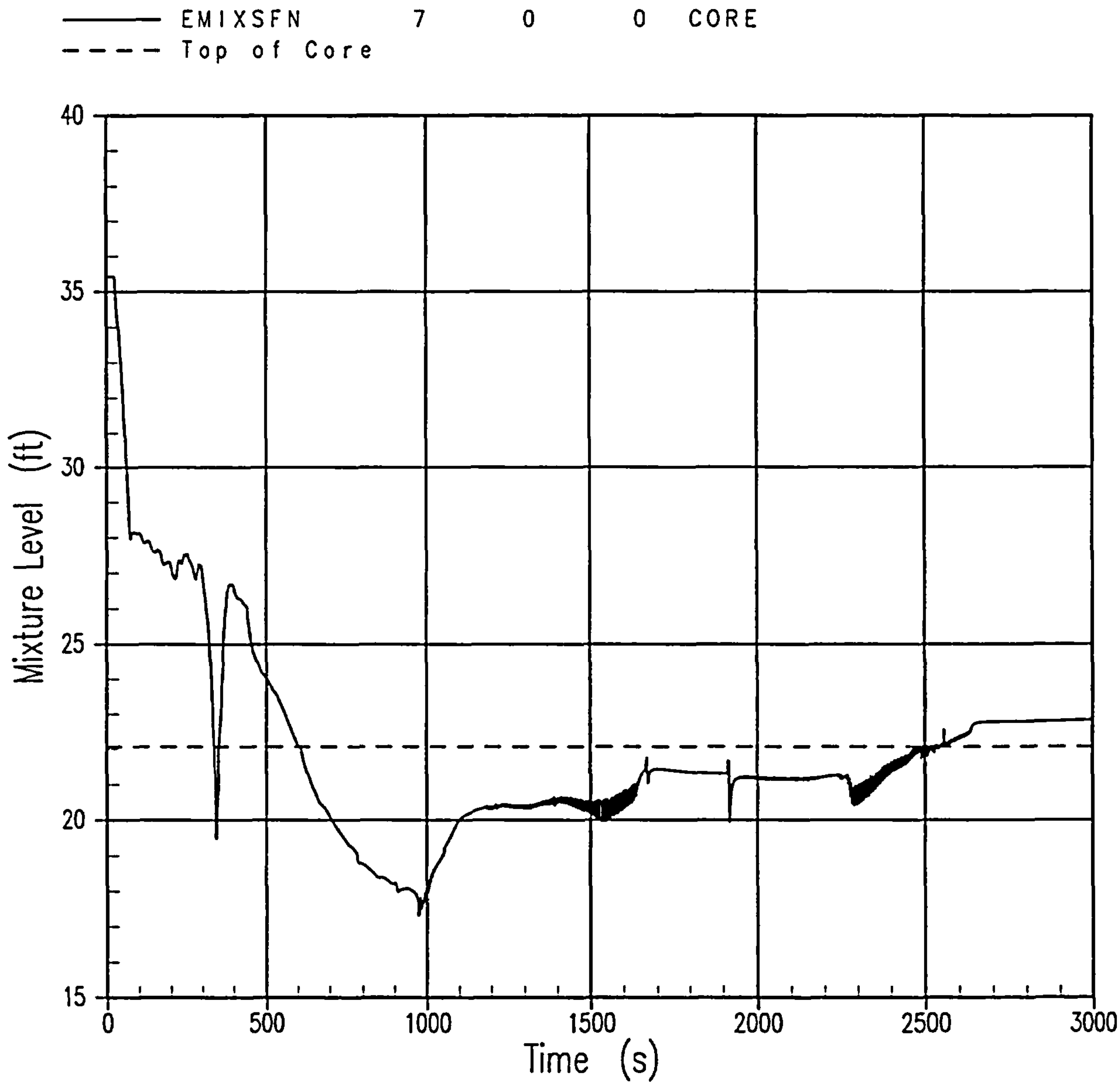

Figure 6.2-10
4-Inch Break, Core Mixture Level

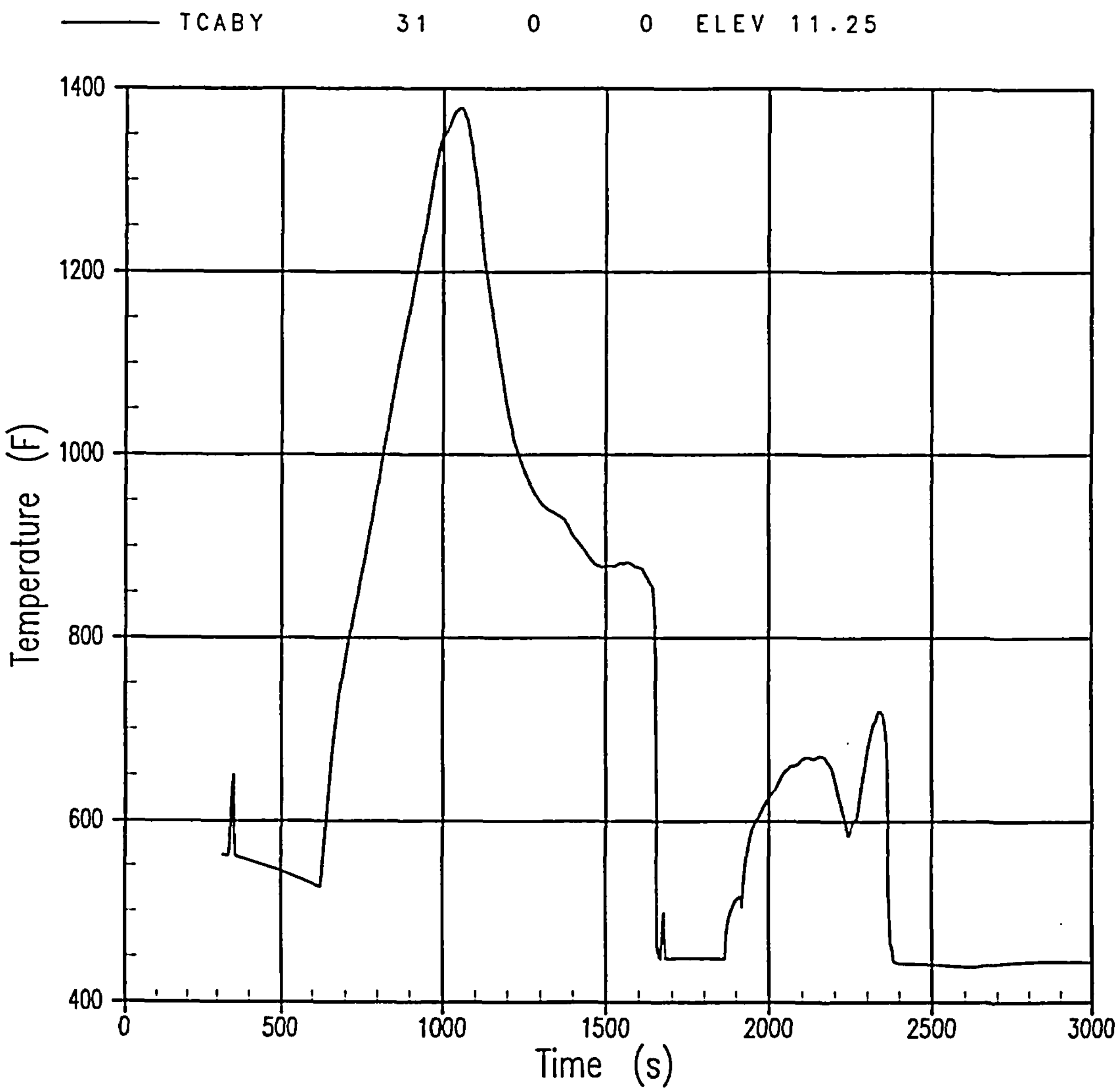

Figure 6.2-11

4-Inch Break, PCT at PCT Elevation (11.25 ft)

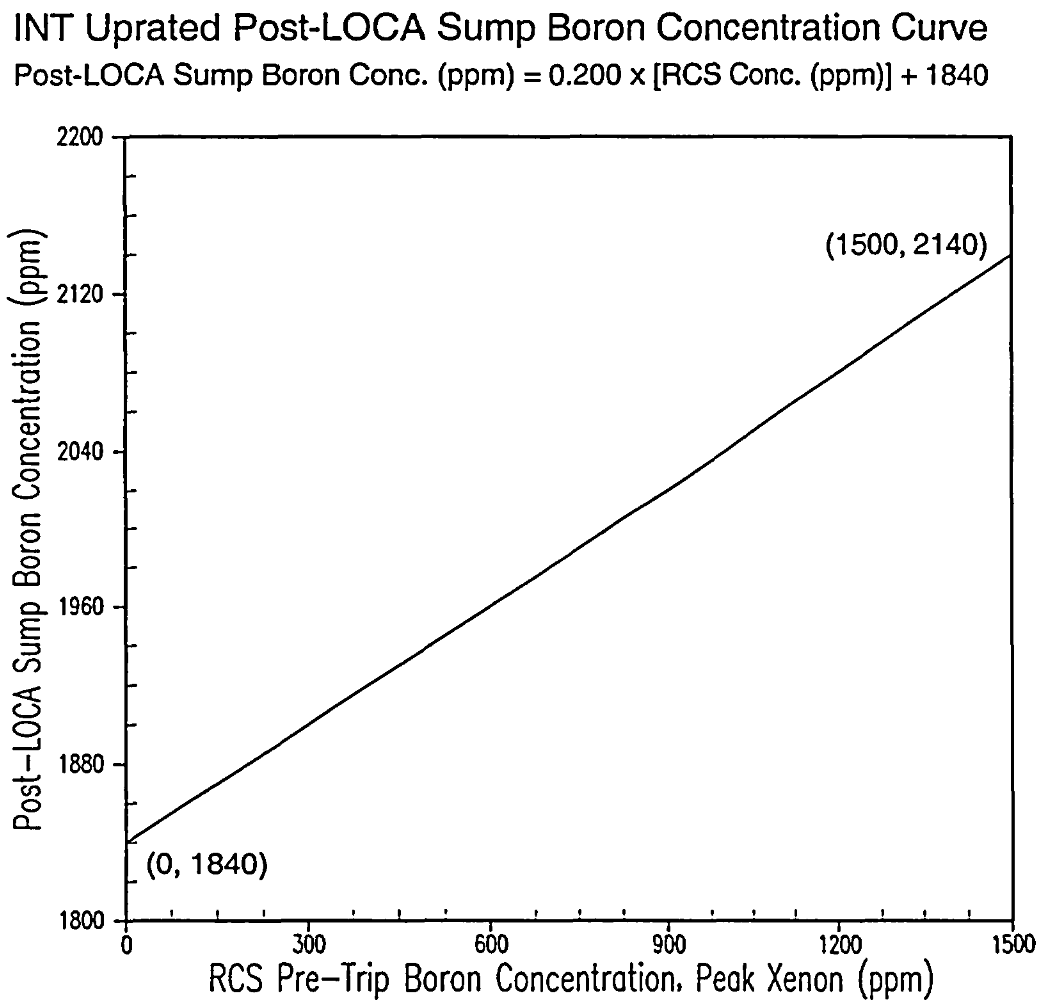

Figure 6.2-12

Post-LOCA Sump Boron Concentration Curve

6.3 Non-Loss-of-Coolant Accident Transients

6.3.1 Introduction

To support the Indian Point Unit 3 (IP3) stretch power uprate (SPU), all of the *Updated Final Safety Analysis Report* (UFSAR) Chapter 14 non-loss-of-coolant accident (LOCA) analyses were evaluated to determine the acceptability of plant operation at the uprated conditions. The uprated conditions addressed are those defined in Table 2.1-2 of this report for the IP3 SPU. The non-loss-of-coolant accident (non-LOCA) events considered herein are listed in Table 6.3-1, along with the corresponding section number in this report and the applicable UFSAR section(s).

The non-LOCA safety analysis methodology used to support the SPU was the same as that applied for the current licensing basis non-LOCA analyses. For some non-LOCA events, the SPU analyses were performed using the RETRAN-02 (RETRAN) computer code, which employs the same methods and methodology used in the current non-LOCA safety analyses that use the LOFTRAN code. For certain applications, RETRAN was used in combination with other computer codes, such as VIPRE-01 (VIPRE) for reactor core subchannel thermal-hydraulic calculations, a neutronic code such as ANC, and a fuel performance code such as PAD (as described in Section 1 of this document). RETRAN is approved for use in non-LOCA safety analyses by the NRC in the *Safety Evaluation Report* (SER) for WCAP-14882-P-A (Reference 1).

Table 6.3-1 contains a list of non-LOCA events along with the corresponding non-LOCA computer codes used. The RETRAN code has been explicitly approved by the NRC for use on each of the non-LOCA events that were analyzed using RETRAN for the SPU (as shown in Table 6.3-1 of this report and documented in Table 1 of the SER of WCAP-14882-P-A [Reference 1]). The RETRAN model used in the IP3 non-LOCA SPU safety analyses simulates a Westinghouse four-loop plant design, applicable to IP3, as described and presented in WCAP-14882-P-A. For each non-LOCA event analyzed, a conservative set of initial conditions and input assumptions was used to generate a conservative, plant-specific transient condition. The event and analysis conditions are provided for each non-LOCA event in subsections 6.3.2 through 6.3.15 of this document. In performing the required analyses for reload cores, Westinghouse uses approved methodology (Reference 2), which provides for using conservative code input so as to bound the expected conditions for subsequent reloads.

Where applicable, the Revised Thermal Design Procedure (RTDP) methodology discussed in WCAP-11397-P-A (Reference 3) was used in the non-LOCA analyses. The RTDP methodology statistically combines the uncertainties of the plant operating parameters (for example, power, temperature, pressure, and flow) into the design limit departure from nucleate boiling ratio

limit DNBR values that are used as an acceptance criterion in the DNBR-related non-LOCA analyses.

In conjunction with the SPU, the non-LOCA safety analyses support several other related changes that directly affect the UFSAR Chapter 14 non-LOCA safety analyses. These changes are summarized in the sections that follow.

Power Uprating

The changes in plant conditions that were considered to be directly associated with the SPU are shown in Tables 2.1-1 and 2.1-2 of this document, and discussed below.

NSSS power was increased from 3082 to 3230 MWt. This resulted in an increase in reactor power from 3068 to 3216 MWt, and a corresponding increase in rod average linear power from 6.34 to 6.644 kW/ft.

IP3 measured flow values provided sufficient margin to increase minimum measured flow and thermal design flow (TDF). Thermal design flow was increased from 323,600 to 354,400 gpm for the SPU. The minimum measured flow (MMF), used in conjunction with the statistical RTDP departure from nucleate boiling (DNBR) methodology described in subsection 6.1.4.1, was increased from 330,800 to 364,700 gpm. These flows were increased to provide margin for DNB-related accidents and transients. Core bypass flow fractions of 7.5 percent (non-statistical) and 6.8 percent (statistical) were assumed. These core bypass flow conditions were increased from those currently analyzed to support a possible upper head temperature reduction in the future.

The maximum reactor vessel average coolant temperature (T_{avg}) was decreased from 574.7° to 572.0°F. The minimum full-power T_{avg} was assumed to be 549.0°F.

The non-LOCA safety analyses now support a range of main feedwater temperatures. The full-power feedwater temperature range is 390.0° to 433.6°F for an NSSS power of 3230 MWt and 390.0° to 431.5°F for an NSSS power of 3182 MWt. The previous analyses supported a full-power feedwater temperature of 427.8°F. The feedwater temperature at hot zero power (HZP) conditions is assumed to be 70°F. Feedwater temperatures at part-power conditions increased proportionally with power between HZP and full-power conditions.

The maximum steam generator tube plugging (SGTP) levels were decreased from 24-percent uniform/30-percent peak to 10-percent uniform for the Model 44F steam generators. Symmetric reactor coolant loop (RCL) flow conditions consistent with a maximum 10-percent uniform SGTP were assumed.

Overtemperature ΔT and Overpower ΔT Reactor Trip Setpoints

The overtemperature ΔT and overpower ΔT (OTΔT/OPΔT) reactor trip functions were assumed to be available in several non-LOCA transient analyses to ensure that the departure from nucleate boiling (DNB) design basis and the fuel centerline melting design basis would be satisfied. The OTΔT and OPΔT reactor trip safety analysis setpoints were generated assuming steady-state conditions and were based on a number of inputs, including the nominal core thermal power and the core thermal safety limits. The core thermal safety limits are the locus of core inlet temperature conditions at which the DNBR is equal to the safety analysis limit value for a range of powers and a range of pressures.

As a result of the increased core thermal power for the SPU and to improve human performance in instrumentation settings at the IPEC site, the safety analysis limit DNBR and core thermal safety limits were revised, resulting in a change to the OTΔT and OPΔT reactor protection trip setpoints. The safety analysis limit DNBR was revised from 1.54 (typical and thimble cell) to 1.45 (typical and thimble cell) based on the WRB-1 DNB correlation. The revised core thermal safety limits presented in Figure 6.3-1 (and Figure 2.1-1 of the *Improved Technical Specifications* [ITS]) were based on the SPU conditions defined in Table 2.1-2 of this report.

The safety analysis values for the OTΔT and OPΔT reactor protection trip setpoints, based on the revised core thermal safety limits, are as follows:

Overtemperature ΔT Reactor Trip Setpoint

$$\Delta T \leq \Delta T_o \left[K_1 - K_2 \left[(1+\tau_1 s) / (1+\tau_2 s)\right] (T_{avg} - T') + K_3 (P - P') - f(\Delta I)\right]$$

Where:

K_1 = 1.42

K_2 = 0.022/°F

K_3 = 0.00070/psi

τ_1 = 25.0 seconds

τ_2 = 3.0 seconds

$T' \leq$ 572°F

P' = 2235 psig

K_1 = Preset manually adjustable bias (fraction)

K_2 = Preset manually adjustable gain based on the effect of temperature on the design limits (1/°F)

K_3 = Preset manually adjustable gain based on the effect of pressure on the design limits (1/psi)

ΔT_o = Reference ΔT, measured at nominal full power for the channel being calibrated (°F)

T_{avg} = Measured average temperature for each calibrated channel (input from instrument racks) (°F)

T' = Reference T_{avg}, measured at nominal full power for the channel being calibrated (°F)

P = Measured pressurizer pressure (input from instrument racks) (psig)

P' = Nominal pressurizer pressure (2235 psig)

$f(\Delta I)$ = Function of the indicated difference between the top and bottom detectors of the power range nuclear ion detectors (see below)

- For each percent that ΔI is < -15.75 percent, reduce the OTΔT trip setpoint by the equivalent of 4.000-percent RTP rated thermal power (RTP).
- For ΔI between –15.75 percent and +6.9 percent, the OTΔT $f(\Delta I)$ function is equal to 0.0.
- For each percent that ΔI is > +6.9 percent, reduce the OTΔT trip setpoint by the equivalent of 3.333-percent RTP.

$(1 + \tau_1 s)/(1 + \tau_2 s)$ = Lead/lag compensation

Where: τ_1 = Preset manually adjustable dynamic compensation time constant (Lead for OTΔT trip setpoint) (seconds)

τ_2 = Preset manually adjustable dynamic compensation time constant (Lag for OTΔT trip setpoint) (seconds)

s = Laplace transform operator ($seconds^{-1}$)

Overpower ΔT Reactor Trip Setpoint

$$\Delta T \leq \Delta T_o [K_4 - K_5 [(\tau_3 s) / (1 + \tau_3 s)] (T_{avg}) - K_6 (T_{avg} - T')]$$

Where: K_4 = 1.164

K_5 = 0.0/°F for decreasing T_{avg}; and

= 0.0175/°F for increasing T_{avg}

K_6 = 0.0/°F for $T_{avg} \leq T'$; and

= 0.0015/°F for $T_{avg} > T'$

τ_3 = 10.0 seconds

$T' \leq$ 572°F

K_4 = Preset manually adjustable bias (fraction)

K_5 = Preset manually adjustable gain that compensates for piping and thermal time delays (1/°F)

K_6 = Preset manually adjustable gain that accounts for the effects of coolant density and heat capacity on the relationship between ΔT and thermal power (1/°F)

ΔT_o = Reference ΔT, measured at nominal full power for the channel being calibrated (°F)

T_{avg} = Measured average temperature for each calibrated channel (input from instrument racks) (°F)

T' = Reference T_{avg}, measured at nominal full power for the channel being calibrated (°F)

$(\tau_3 s)/(1 + \tau_3 s)$ = Rate/lag compensation

Where: τ_3 = Preset manually adjustable dynamic compensation time constant (rate lag time constant for OPΔT trip setpoint) (seconds)

s = Laplace transform operator (seconds^{-1})

The safety analysis values assumed for the time constants (first order lags) on the measurements of T_{avg} and ΔT used in the OTΔT and OPΔT equations are 4.5 seconds.

The nominal values assumed for T_{avg} and pressure in the OTΔT and OPΔT setpoint calculations bound the SPU conditions for a nominal operating T_{avg} from 549.0 to 572.0°F.

With respect to Reactor Coolant System (RCS) pressure, the OTΔT and OPΔT reactor trip functions were applicable for a range of pressurizer pressures from 1850 to 2470 psia. This analyzed range bounds pressure conditions between the low- and high-pressurizer pressure reactor trip settings with consideration given to the appropriate uncertainties.

To ensure proper operation of the OTΔT and OPΔT reactor trip functions over the entire range of applicable full power operating RCS temperatures (T_{avg} from 549.0° to 572.0°F), the instrumentation must be capable of measuring temperatures over the following ranges:

$$511°F \leq T_{cold} \leq 596°F$$

$$547°F \leq T_{avg} \leq 615°F$$

$$583°F \leq T_{hot} \leq 634°F$$

Also, to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a reduced, more realistic range of applicable full power operating RCS temperatures (T_{avg} from 562.0° to 572.0°F), the instrumentation must be capable of measuring temperatures over the following ranges:

$$525°F \leq T_{cold} \leq 596°F$$

$$560°F \leq T_{avg} \leq 615°F$$

$$596°F \leq T_{hot} \leq 634°F$$

As such, the revised instrumentation ranges that have been chosen for IP3 after implementation of the SPU to ensure proper operation of the OTΔT and OPΔT reactor trip functions over a realistic full power operating T_{avg} range of 562.0° to 572.0°F are as follows:

$$520°F \leq T_{cold} \leq 640°F$$

$$540°F \leq T_{avg} \leq 615°F$$

$$520°F \leq T_{hot} \leq 640°F$$

Should a cycle-specific full power operating T_{avg} value be chosen to be below 562.0°F, the instrumentation ranges will need to be revised to protect the more broad ranges presented above for a full power operating T_{avg} range of 549.0° to 572.0°F.The effect of the change in the core thermal safety limits as well as the resulting changes in the OTΔT and OPΔT reactor

protection trip setpoints are addressed for non-LOCA transients in the evaluations and analyses described in the following sections.

Auxiliary Feedwater

To support the SPU, a requirement was specified for additional auxiliary feedwater (AFW) flow to preclude a pressurizer water-solid condition for the loss-of-normal feedwater (LONF) and loss-of-all AC power (LOAC) to the station auxiliaries event analyses. The LONF and LOAC events address an LONF (from pump failures, valve malfunctions, or LOAC), which results in a reduction in capability of the secondary system to remove heat generated in the reactor core. If an alternate source of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point at which water relief from the pressurizer occurs, potentially generating a more serious plant condition without other incidents occurring independently. To ensure acceptable results were obtained in the LONF/LOAC event analyses (addressed in subsections 6.3.7 and 6.3.8), operator action was assumed at 10 minutes following reactor trip to align an additional train of AFW (aside from the single motor-driven AFW train automatically actuated on a low-low steam generator water level signal).

Neutronics/Reactivity Modeling

To support future reload design activities with the uprated core power, several neutronics-related analysis input assumptions were changed.

- To provide margin for future reload design activities, the change in boron concentration from the maximum critical boron concentration (with all rods inserted) to a critical boron concentration at which k-effective < 0.95 was increased from 570 to 660 ppm for the Mode 6 (refueling) boron dilution analysis. The Mode 6 boron dilution analysis is presented in subsection 6.3.5 of this document.

- To support the uncontrolled rod cluster control assembly (RCCA) withdrawal at power analysis with respect to RCS overpressure concerns, the maximum reactivity insertion rate was limited to ≤66 pcm/sec (88 pcm/in), corresponding to maximum differential RCCA worth at maximum RCCA withdrawal rate. The analysis of this event is discussed in subsection 6.3.3.

Fuel Temperatures

Revised fuel temperatures generated in support of the SPU conditions were applied as appropriate in the non-LOCA safety analyses.

Reactor Trip

The various instrumentation delays associated with each reactor trip function were conservatively modeled in the non-LOCA safety analyses. The total delay time is defined as the time from when trip conditions are reached to the time the rods are free to fall. The safety analysis trip setpoint and maximum time delay assumed in the non-LOCA safety analysis for each reactor trip function at SPU conditions are shown in Table 6.3-2.

Table 6.3-3 summarizes key analysis assumptions considered in the IP3 SPU non-LOCA analyses and evaluations.

Event Classification

The non-LOCA accidents are classified by the American Nuclear Society (ANS) as Condition II, III, or IV events. The ANS categorizes events based upon expected frequency of occurrence and severity as follows.

- Condition I: Normal operation and operational transients
- Condition II: Faults of moderate frequency
- Condition III: Infrequent faults
- Condition IV: Limiting faults

Condition I events are normal operation incidents that are expected to occur frequently or regularly. These occurrences are accommodated with margin between any plant parameter and the value of that parameter that would require either automatic or manual protective action.

Condition II events (which are the majority of the non-LOCA events) are incidents of moderate frequency that may reasonably occur during a calendar year of operation. These faults, at worst, result in a reactor trip with the plant capable of returning to power operations after corrective actions. Condition II incidents will not generate a more serious accident (Condition III or IV) without other incidents occurring independently.

Condition III events are infrequent faults that may reasonably occur during the lifetime of a plant. These faults will not cause more than a small fraction of fuel elements to be damaged. No consequential loss of function of the RCS or containment as fission product barriers can occur. The release of radioactive materials to unrestricted areas may exceed 10CFR20 limits; however, they will not be enough to interrupt or restrict public use of those areas beyond the exclusion radius. Condition III incidents will not generate a more serious accident (Condition IV) without other incidents occurring independently.

Condition IV events are limiting faults that are not expected to occur but are postulated because their consequences would include the potential for significant radioactive releases. The release of radioactive material will not result in an undue risk to public health and safety exceeding the guidelines of 10CFR100. No consequential loss of function of systems required to mitigate the event can occur.

The results of all analyses and evaluations demonstrated that applicable safety analysis acceptance criteria were satisfied at the SPU conditions detailed in Table 2.1-2 of this report.

6.3.2 Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition

6.3.2.1 Introduction

An RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of control rods resulting in a power excursion. While the probability of a transient of this type is extremely low, operator action or a malfunction of the Reactor Control Rod Drive System could cause such a transient. This could occur with the reactor either subcritical or at power. The at-power case is discussed later in subsection 6.3.3.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from shutdown to low power during startup by RCCA withdrawal or by reducing the reactor coolant boron concentration. RCCA motion can cause much faster changes in reactivity than could occur from changing the boron concentration.

The RCCA drive mechanisms are wired into pre-selected bank configurations that remain the same throughout reactor life. These circuits prevent the RCCAs from being automatically withdrawn in other than their respective banks. Power supplied to the banks is controlled so that no more than two banks can be withdrawn at the same time and in their defined withdrawal sequence. The RCCA drive mechanisms are of the magnetic latch type, and coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming simultaneous withdrawal of the combination of the two sequential control banks having the maximum combined worth at maximum speed. The maximum reactivity insertion rate, even with these assumptions, is well within the capability of the Reactor Protection System (RPS) to prevent core damage.

Should a continuous RCCA withdrawal be initiated, the following automatic features of the RPS will terminate the transient:

- Source range neutron flux reactor trip - actuated when either of two independent source range channels indicate above a pre-selected, manually adjustable setpoint. This trip function can be manually bypassed only after either of two intermediate range flux channels indicate above a specified level. It is automatically reinstated when both intermediate channels indicate below a specified level.

- Intermediate-range neutron-flux reactor trip - actuated when either of two independent intermediate range channels indicate above a pre-selected, manually adjustable setpoint. This trip function can be manually bypassed only after 2 of 4 power range channels indicate above approximately 10 percent full-power. It is automatically reinstated when 3 of 4 channels indicate below this value.

- Power-range high-neutron-flux reactor trip (low setting) - actuated when 2 of 4 power range channels indicate above approximately 25 percent full-power. This trip function can be manually bypassed when 2 of 4 power range channels indicate above approximately 10 percent full-power. It is automatically reinstated when 3 of 4 channels indicate below this value.

- Power-range high-neutron-flux reactor trip (high setting) - actuated when 2 of 4 power range channels indicate above a preset setpoint. This trip function is always active.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast initial increase terminated by the reactivity feedback effect of the negative Doppler power coefficient. This self-limitation of the initial power increase is of prime importance since it limits nuclear power to an acceptable level prior to protection system action. After the initial increase, the nuclear power is momentarily reduced and then, if the incident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

Termination of the startup transient by the above protection channels prevents fuel damage. In addition, control rod stops on high-intermediate range flux level (1 of 2) and high-power range flux level (1 of 4) serve to halt rod withdrawal and prevent the need to actuate the intermediate range flux level trip and power range flux level trip, respectively.

6.3.2.2 Input Parameters and Assumptions

The Standard Thermal Design Procedure (STDP) was used in the accident analysis. To obtain conservative results for the analysis, the following assumptions were made concerning initial reactor conditions:

- *Since the magnitude of the nuclear power peak reached during the initial part of the* transient, for any given rate of reactivity insertion, is strongly dependent on the Doppler power reactivity coefficient, a conservatively low (least negative) value was used.

- The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because heat transfer time between the fuel and moderator is much longer than nuclear flux response time. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. Accordingly, the most positive moderator temperature coefficient was assumed since this yields the maximum rate of power increase.

- The analysis assumed the reactor to be at HZP conditions with a nominal temperature of 547°F. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions) because it yields a larger fuel-to-moderator heat transfer coefficient, a larger specific heat of both moderator and fuel, and a less-negative (smaller absolute magnitude) Doppler coefficient. The less-negative Doppler coefficient reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel-specific heat and larger heat transfer coefficient yields a larger peak heat flux. The analysis also assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

- Reactor trip is assumed on power-range high-neutron flux (low setting). The most adverse combination of instrumentation error, setpoint error, delay for trip signal actuation, and delay for control rod assembly release is taken into account. The analysis assumes a 10-percent uncertainty in power range flux trip setpoint (low setting), raising it from the nominal value of 25 to 35 percent. During the transient, the rise in nuclear power is so rapid that the effect of error in the trip setpoint on the actual time of rod release is negligible. In addition, total reactor trip reactivity is based on the assumption that the highest worth control rod assembly is stuck in its fully withdrawn position.

- The maximum positive reactivity insertion rate assumed is greater than that for simultaneous withdrawal of the two sequential control banks having the greatest combined worth at maximum speed (45 inch/min, which corresponds to 72 steps/min).

- The DNB analysis assumes the most limiting axial and radial power shapes associated with having the two highest combined worth banks in their high-worth position.

- The analysis assumes initial power to be below that expected for any shutdown condition (10^{-9} fraction of nominal power). The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.

- The analysis assumes only two reactor coolant pumps (RCPs) in operation. This is conservative with respect to the DNB transient.

6.3.2.3 Description of Analysis

The analysis of the uncontrolled-RCCA-bank-withdrawal-from-subcriticality event was performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 4), was used to calculate the core average nuclear power transient, including various core feedback effects, that is, Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 5) 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. Finally, the average heat flux calculated by FACTRAN was used in the VIPRE (Reference 8) computer code for transient DNBR calculations.

6.3.2.4 Acceptance Criteria

The uncontrolled-RCCA-bank-withdrawal-from-subcritical event is considered an ANS Condition II event, a fault of moderate frequency, and is analyzed to ensure that the core and RCS are not adversely affected. This is demonstrated by showing that the minimum DNBR remains above the applicable safety analysis limit and that peak hot spot fuel and clad temperatures remain within acceptable limits.

6.3.2.5 Results

The results of the uncontrolled-RCCA-bank-withdrawal from subcritical analysis performed at the SPU conditions show that the minimum DNBR remains above the safety analysis limit at all times (see subsection 7.2.3.2.6) and that peak fuel centerline temperature remains below that at which fuel melt occurs, as demonstrated in Table 6.3-18. The calculated sequence of events is shown in Table 6.3-4. The nuclear power transient, thermal flux transient, and the clad and fuel temperature transients for this accident are shown in Figures 6.3-2 through 6.3-5, respectively.

6.3.2.6 Conclusions

In the event of an RCCA withdrawal incident from the subcritical condition, the core and RCS would not be adversely affected since the combination of thermal power and coolant temperature results in a minimum DNBR greater than the safety analysis limit. Furthermore, since the maximum fuel temperatures predicted to occur during this event are much less than those required for fuel melting (4800°F), no fuel damage is predicted as a result of this transient at SPU conditions. Clad damage is also precluded since clad temperatures remain within acceptable limits.

6.3.3 Uncontrolled RCCA Assembly Withdrawal at Power

6.3.3.1 Introduction

An uncontrolled-RCCA-bank-withdrawal-at-power event that causes an increase in core heat flux could be the result of an operator error or a malfunction in the Rod Control System. Immediately following initiation of the accident, the steam generator heat removal rate lags behind the core power generation rate. This imbalance between heat removal and heat generation rate causes the reactor coolant temperature to rise. Unless terminated, the power increase and resultant coolant temperature rise could eventually result in DNB and/or fuel centerline melt. Therefore, to avoid damage to the core, the RPS is designed to automatically terminate the transient before the DNBR falls below the safety analysis limit or the fuel rod linear heat generation rate (kw/ft) limit is exceeded.

The automatic RPS features that prevent core damage in an RCCA-bank-withdrawal-incident at-power by actuating a reactor trip include the following:

- Any 2-out-of-4 power range high neutron flux channels exceed the overpower setpoint.
- Any 2-out-of-4 ΔT channels exceed the OTΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature, and coolant average pressure to protect against DNB.
- Any 2-out-of-4 ΔT channels exceed the OPΔT setpoint. This setpoint is automatically varied with coolant average temperature so that the allowable heat generation rate (kw/ft) is not exceeded.
- Any 2-out-of-3 high-pressurizer pressure channels exceed the fixed setpoint. This setpoint is less than the set pressure for the PSVs.
- Any 2-out-of-3 high-pressurizer water level channels exceed the fixed setpoint.

In addition to the above listed reactor trips, there are several RCCA bank withdrawal blocks that are not credited in the accident analyses but would serve to limit the severity of this event. These are:

- High neutron flux (1-out-of-4 power range channels)
- OTΔT (1-out-of-4 channels)
- OPΔT (1-out-of-4 channels)

6.3.3.2 Input Parameters and Assumptions

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented in subsection 6.3.3.5 are representative for this event.

For an uncontrolled-RCCA-bank-withdrawal-at-power accident, the following conservative assumptions are made:

- For the analysis of the minimum DNBR and peak secondary pressure this accident is analyzed with the RTDP (Reference 3). Therefore, initial reactor power, pressurizer pressure, and RCS temperatures are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit. For the analysis of peak RCS pressure, uncertainties in the initial conditions for power, pressurizer pressure and T_{avg} are conservatively applied.

- For reactivity coefficients, two cases are analyzed.

  — Minimum Reactivity Feedback: A zero moderator density coefficient and a least-negative Doppler-only power coefficient form the basis for the BOL minimum reactivity feedback assumption.

  — Maximum Reactivity Feedback: A conservatively large positive moderator density coefficient of 0.54 $\Delta k/g/cm^3$ (corresponding to a large negative MTC) and a most-negative Doppler-only power coefficient formed the basis for the EOL maximum reactivity feedback assumption.

- The reactor trip on high neutron flux is actuated at a value of 118-percent nominal full power, which accounts for all adverse instrumentation and setpoint errors. The ΔT trips included all adverse instrumentation and setpoint errors, with maximum delay for trip signal actuation. A high-pressurizer pressure reactor trip setpoint of 2470 psia, which accounts for all adverse instrumentation and setpoint errors, is assumed in the analysis of the peak RCS pressure.

- The RCCA trip insertion characteristic is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position.

- A range of reactivity insertion rates is examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of two sequential control rod banks having the maximum combined differential rod worth at a conservative speed (45 inches/minute, which corresponds to 72 steps/minute).

- Initial power levels of 10, 60, and 100 percent are considered.

- The effect of a full-power RCS T_{avg} window is considered for the uncontrolled-RCCA-bank-withdrawal-at-power analysis. The high end of the full-power T_{avg} window is explicitly analyzed since this is limiting with respect to the DNBR results. For part-power levels, the initial RCS T_{avg} is based on the programmed T_{avg} and the corresponding initial power level.

- The effect of a feedwater temperature window is also considered. The low end of the full-power feedwater temperature window was determined to be limiting with respect to the DNBR results.

6.3.3.3 Description of Analysis

This analysis demonstrates how the protection functions actuate for various combinations of reactivity insertion rates, initial power levels and reactivity feedback conditions.

The rod-withdrawal-at-power event is analyzed with the RETRAN computer code (Reference 1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and main steam safety valves (MSSVs). The program computes pertinent plant variables including temperatures, pressures, power level, and DNBR.

6.3.3.4 Acceptance Criteria

Based on its frequency of occurrence, the uncontrolled-RCCA-bank-withdrawal-at-power accident is considered to be a Condition II event as defined by the ANS. The following items summarize the main acceptance criteria associated with this event.

The critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

Pressure in the RCS and Main Steam System (MSS) should be maintained below 110 percent of the corresponding design pressures.

6.3.3.5 Results

The results of the uncontrolled-RCCA-withdrawal at power analysis performed at the SPU conditions show that the minimum DNBR remains above the safety analysis limit at all times and that peak RCS and MSS pressures are maintained below 110 percent of the corresponding design pressures, as demonstrated in Table 6.3-18.

Figures 6.3-6 through 6.3-11 show the transient response for a rapid uncontrolled-RCCA-bank-withdrawal incident (66 pcm/sec) starting from 100-percent power with minimum reactivity feedback. Reactor trip on high neutron flux occurs shortly after the start of the accident. Because of the rapid change in nuclear power with respect to the thermal time constants of the fuel, an immediate reactor trip ensures margin to the DNBR safety analysis limit is maintained.

The transient response for a slow uncontrolled RCCA bank withdrawal (1 pcm/s) from 100-percent power with minimum reactivity feedback is shown in Figures 6.3-12 through 6.3-17. Reactor trip on OTΔT occurs after a much longer period, and the temperature rise was consequently larger. Again, the minimum DNBR is greater than the safety analysis limit.

Figure 6.3-18 shows the minimum DNBR as a function of reactivity insertion rate from 100-percent power for both minimum and maximum reactivity feedback conditions. The high neutron flux and OTΔT reactor trip functions provide DNB protection over the range of reactivity insertion rates. The minimum DNBR is greater than the safety analysis limit.

Figures 6.3-19 and 6.3-20 show the minimum DNBR as a function of reactivity insertion rate for RCCA-bank-withdrawal incidents starting at 60- and 10-percent power, respectively. The results are similar to the 100-percent power case. However, as the initial power level

decreases, the range over which the OTΔT trip provides protection is effectively increased. In no case does the DNBR fall below the safety analysis limit.

The calculated sequence of events for the two cases discussed above is shown in Table 6.3-5. With the reactor tripped, the plant returns to a stable condition. The plant can subsequently be cooled down further by following normal plant shutdown procedures.

6.3.3.6 Conclusions

The high neutron flux and OTΔT reactor trip functions provide adequate protection over the entire range of possible reactivity insertion rates, that is, the minimum value of the DNBR is always greater than the safety analysis limit. The RCS and MSS are maintained below 110 percent of their design pressures. Therefore, the results of the analysis demonstrate that an uncontrolled-RCCA-withdrawal-at power does not adversely affect the core, RCS, or MSS, and all applicable acceptance criteria are met.

6.3.4 RCCA Drop/Misoperation

6.3.4.1 Introduction

RCCA misoperation accidents include the following:

- One or more dropped RCCAs within the same group
- A dropped RCCA bank
- A statically misaligned RCCA

Each RCCA has a position indicator channel that displays the position of the assembly in a display grouping that is convenient to the operator. Fully inserted RCCAs are also indicated by a rod-at-bottom signal that actuates a local alarm and control room annunciator. Group demand position is also indicated.

RCCAs move in preselected banks, and the banks always move in the same preselected sequence. Each bank of RCCAs consists of two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially so that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or de-actuation) of the stationary gripper, movable gripper, and lift coils of the control rod drive mechanism (CRDM) withdraws the RCCA held by the mechanism. Mechanical failures are in the direction of insertion or immobility. Note that the operator can deliberately withdraw a single RCCA in a control or shutdown bank since this feature is necessary to retrieve an assembly should one drop accidentally.

A dropped RCCA or RCCA bank is detected by:

- Sudden drop in the core power level as seen by the Nuclear Instrumentation System (NIS)
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod-at-bottom signal
- Rod deviation alarm
- Rod position indication

Dropping of a full-length RCCA is assumed to be initiated by a single electrical or mechanical failure that causes any number and combination of rods from the same group of a given control bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor can occur due to the skewed power distribution representative of a dropped rod configuration. For this event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions that exist following a dropped RCCA.

Misaligned RCCAs are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples
- Rod deviation alarm
- Rod position indicators

The resolution of the rod position indicator channel is ±5 percent of span (±7.2 inches). Any RCCA can deviate from its group within the limits specified in Table 3.1.4-1 of the ITS (above 85-percent RTP) or within 24 steps (at or below 85-percent RTP) and not cause power distributions exceeding design limits. The deviation alarm alerts the operator when any rod deviates from its group position by more than 5 percent of span. If the rod deviation alarm is not operable, the operator must take action as required by the plant *Technical Specifications.*

6.3.4.2 Input Parameters and Assumptions

For one or more dropped RCCA(s) in the same group, transient statepoints are generated generically and evaluated on a plant-specific, cycle-specific basis, to determine if the acceptance criteria are met. The statepoints, in the form of changes in key parameters from the initial values, are calculated based on the following conservative assumptions.

- This accident is analyzed with the RTDP (Reference 3). Therefore, initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit calculated using the referenced methodology.

- The transient statepoints are based on generic dropped rod analyses specifically performed to support elimination of turbine runback (on dropped rod). The statepoint analysis bounds a dropped RCCA event for single or multiple dropped RCCAs from the same group of a given bank simulating rod withdrawal block. The statepoint analysis also bounds operation with automatic rod control for all possible single dropped rod worths to address the possibility of a single failure in the rods-on-bottom signal that blocks automatic rod withdrawal.

- A range of MTCs from 0 to -35 pcm/°F was analyzed, which bounds the limiting time in life.

- A range of negative reactivity insertions from 100 to 1000 pcm is assumed to simulate the dropped RCCA event.

- To provide a conservative analysis that minimizes the DNBR, the pressure-reducing functions of the automatic pressure control system are modeled. The pressure-reducing functions modeled are the pressurizer power-operated relief valves (PORVs) and spray.

6.3.4.3 Description of Analysis

Dropped RCCA(s) and RCCA Bank

The transient response following a dropped RCCA event was calculated using a detailed digital simulation of the plant. A dropped RCCA or dropped RCCA bank caused a step decrease in reactivity and the resulting core power generation was determined using the LOFTRAN computer code (Reference 6). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, Rod Control System, steam generators, and steam generator safety valves. The code computes pertinent plant variables including

temperatures, pressures, and power level. Since LOFTRAN employs a point neutron kinetics model, a dropped rod event was modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped RCCA(s), regardless of the actual configuration of the rod(s) that dropped.

For the evaluation of the dropped RCCA event, generic transient statepoints designed to bound specific plant types were examined and found to be applicable (bounding) for IP3 at SPU conditions. The statepoints representing transient system conditions at the limiting point in the transient were calculated by the LOFTRAN code. No credit for any direct trip due to the dropped RCCA(s) was taken in the generic analysis. The generic analysis also assumed no automatic power reduction features (that is, turbine runback) were actuated by the dropped RCCA(s). The statepoints were provided for conditions that covered the range of reactivity parameters expected to occur during core life.

The statepoints and nuclear models specific for IP3 were used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis was shown to be met using the dropped rod limit lines developed with the Westinghouse version of the VIPRE computer code (Reference 8). 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 7).

Statically Misaligned RCCA

For the statically misaligned RCCA event, steady-state power distributions were analyzed at SPU power conditions (3216-MWt core) using appropriate nuclear physics computer codes. The VIPRE computer code (Reference 8) was used to determine the $F_{\Delta H}$ peaking factor limits that can meet the safety analysis limit DNBR. The analysis examined the case of the worst rod withdrawn from bank D inserted at the insertion limit with the reactor initially at full power. The analysis assumed this incident to occur at BOL since this resulted in the minimum feedback value (least negative) of the MTC. This assumption maximizes the power rise and minimizes the tendency of the large MTC (most negative) to flatten the power distribution.

6.3.4.4 Acceptance Criteria

Based on frequency of occurrence, a misaligned or dropped RCCA is considered a Condition II event as defined by the ANS. The limiting acceptance criteria for these events is that the critical heat flux should not be exceeded, as demonstrated by precluding DNB, and the peak linear heat generation rate should not exceed a value that could cause fuel centerline melt.

6.3.4.5 Results

Dropped RCCA(s) and RCCA Bank

Following one or more dropped RCCA(s) from the same group, a negative reactivity insertion results. The core is not adversely affected during this period since power is decreasing rapidly. Following the RCCA drop(s), the plant establishes a new equilibrium condition. Depending on the worth of the dropped RCCA(s), power can be reestablished by reactivity feedback. Power may also be recovered as a result of automatic rod control.

When reactivity feedback does not offset the worth of the dropped RCCA(s) with manual rod control assumed (automatic rod withdrawal blocked), there is a cooldown condition until a low pressurizer-pressure reactor trip signal is reached. Figures 6.3-21 through 6.3-23 show a typical transient response at BOL conditions with a small negative MTC of -5 pcm/°F for a dropped RCCA worth of 400 pcm.

When reactivity feedback is large enough to offset the worth of the dropped RCCA(s) with manual rod control assumed (automatic rod withdrawal blocked), reactor power is reestablished at a new equilibrium condition. Figures 6.3-24 through 6.3-26 show a typical transient response at EOL conditions with a large negative MTC of -35 pcm/°F for a dropped RCCA worth of 400 pcm.

With automatic rod control functioning, reactor power promptly drops to a minimum due to the negative reactivity insertion associated with the dropped RCCA(s), and is then recovered under rod control. Figures 6.3-27 through 6.3-29 show a typical transient response at BOL conditions with a small negative MTC of -5 pcm/°F for a dropped RCCA worth of 200 pcm.

With automatic rod control functioning and EOL conditions assumed, the reactor power overshoot is effectively dampened due to the reactivity inserted via cooldown of the RCS as opposed to rods. Figures 6.3-30 through 6.3-32 show a typical transient response at EOL conditions with a large negative MTC of -35 pcm/°F for a dropped RCCA worth of 200 pcm.

In all cases, the minimum DNBR remains above the safety analysis limit DNBR and the peak fuel centerline melt temperature criterion at the SPU condition is met, as demonstrated in Table 6.3-18.

Following plant stabilization, the operator can manually retrieve a dropped RCCA by following approved operating procedures.

Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR occur at significant power levels. These situations arise from cases in which one RCCA is fully inserted or where bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alerts the operator well before the transient approaches the postulated conditions. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the safety analysis limit.

The insertion limits in the COLR may vary from time to time depending on several limiting criteria. The insertion limits on control bank D must be chosen to be above that position that meets the minimum DNBR and peaking factors. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with bank D to its full-power insertion limit and 1 RCCA fully withdrawn, DNBR did not fall below the safety analysis limit when analyzed at SPU conditions. The analysis of this case assumed that the initial reactor power, pressure, and RCS temperature were at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignment with 1 RCCA fully inserted, the DNBR did not fall below the safety analysis limit when analyzed at SPU conditions. The analysis of this case assumed that the initial reactor power, pressure, and RCS temperatures were at their nominal values, with the increased radial peaking factor associated with the misaligned RCCA.

By meeting the DNBR limit for the RCCA misalignment incident there was no reduction in the ability of the primary coolant to remove heat from the fuel rod. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the limiting design axial power distribution. The resulting linear heat generation rate was below that which would cause fuel melting.

6.3.4.6 Conclusions

Following a dropped RCCA(s) event the plant will return to a stabilized condition. Results of the analysis showed that a dropped RCCA event, with or without a reactor trip, did not adversely affect the uprated core since the DNBR remained above the limit for a range of dropped RCCA worths.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (statically misaligned RCCA), the DNBR remained greater than the safety analysis limit at uprated power conditions; thus, there was no reduction in the ability of the primary coolant to remove heat from the fuel rod. After identifying an RCCA group misalignment condition, the operator must take action as required by the plant *Technical Specifications* and operating instructions.

6.3.5 Chemical and Volume Control System Malfunction

6.3.5.1 Introduction

Reactivity can be added to the core with the Chemical and Volume Control System (CVCS) by feeding reactor makeup water into the RCS via the Reactor Makeup Control System. Boron dilution is a manual operation. A Boric Acid Blend System is provided to permit the operator to match the concentration of reactor coolant makeup water to that existing in the coolant at the time. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

There is only a single, common source of dilution water to the blender from the primary water makeup system; inadvertent dilution can be readily terminated by isolating this single source. The operation of the primary water makeup pumps that take suction from the primary water storage tank (PWST) provides the non-borated supply of makeup water to the blender. The boric acid from the boric acid storage tank(s) is blended with the reactor makeup water in the blender, and the composition is determined by the preset flow rates of boric acid and reactor makeup water on the reactor makeup control. The operator must switch from the automatic makeup mode to the dilute mode and move the start-stop switch to start or, alternatively, the boric acid flow controller could be set to zero. Since these are deliberate actions, the possibility of inadvertent dilution is very small. For this dilution water to be added to the RCS, the charging pumps must be running in addition to the primary water makeup pumps. Also, any diluted water introduced into the volume control tank (VCT) must pass through the charging pumps to be added to the RCS.

Thus, the rate of addition of diluted water to the RCS from any source is limited to the capacity of the charging pumps. This addition rate is 294 gpm for all three charging pumps. This is the maximum delivery rate based on a pressure drop calculation comparing the pump curve with the system resistance curve. Normally, only one charging pump is operating while the others are on standby.

Information on the status of the reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the CVCS. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction. Postulated boron dilution events during refueling, startup, and power operation were considered in this analysis.

The CVCS malfunction event was analyzed for the refueling (Mode 6), startup (Mode 2), and power (Mode 1) modes.

6.3.5.1.1 Dilution during Refueling

In a dilution in the refueling mode, the operator has prompt and definite indication of any boron dilution from the audible count rate instrumentation. High count rate is alarmed in the reactor containment and the main control room. The count-rate increase is proportional to the multiplication factor.

6.3.5.1.2 Dilution during Startup

In this mode, the plant is being taken from one long-term mode of operation, hot standby, to another, power operation. Typically, the plant is maintained in the startup mode only for the purpose of startup testing at the beginning of each cycle. During this mode of operation, rod control is in manual. All normal actions required to change power level, either up or down, require operator initiation.

This mode of operation is a transitory operational mode in which the operator intentionally dilutes (borates) and withdraws control rods to take the plant critical. During this mode, the plant is in manual control with the operator required to maintain a high awareness of the plant status. For a normal approach to criticality, the operator has to manually initiate a limited dilution (boration) and subsequently manually withdraw the control rods, a process that takes several hours. The *Technical Specifications* require that the operator ensure that the reactor does not go critical with the control rods below the insertion limits. Once critical, the power escalation must be sufficiently slow to allow the operator to manually block the source range reactor trip after receiving P-6 from the intermediate range. Too fast a power escalation (due to an unknown dilution) would result in reaching P-6 unexpectedly, leaving insufficient time to manually block the source range reactor trip. Failure to perform this manual action could result in a reactor trip and immediate shutdown of the reactor.

6.3.5.1.3 Dilution during Power Operation

In this mode, the plant could be operated in either automatic or manual rod control.

With the reactor in automatic rod control, the power and temperature increase from boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. The rod insertion limit alarms (low and low-low settings) alert the operator that a dilution is in progress. The intent of the analysis in this mode is to show there is sufficient time to determine the cause of the dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost (resulting in a return to critical condition).

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise would cause the reactor to reach the OTΔT trip setpoint resulting in a reactor trip. The boron dilution transient in this case would be essentially equivalent to an uncontrolled-RCCA-bank-withdrawal-at-power event. The maximum reactivity insertion rate for a boron dilution is conservatively estimated to be within the range of insertion rates analyzed in the RCCA bank withdrawal at power analysis. The intent of the analysis is to show there is sufficient time for the operator to determine the cause of the dilution, isolate the reactor water makeup source, and initiate boration before the available shutdown margin is lost (resulting in a return to critical condition).

6.3.5.2 Input Parameters and Assumptions

6.3.5.2.1 Dilution during Refueling

Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.

- One RHR pump providing a minimum flow rate of 1000 gpm is normally running except during short time periods, as allowed by the *Technical Specifications*. A minimum active RCS water volume of 3266 ft^3 is assumed. This corresponds to the active RCS volume while on RHR, and conservatively assumes an RCS vessel filled to mid-loop.

- The initial boron concentration is assumed to be 2050 ppm.

- The critical boron concentration following reactor trip is assumed to be 1390 ppm, corresponding to all rods inserted and no xenon condition. The 660-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.2.2 Dilution during Startup

Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.
- A minimum RCS water volume of 9350 ft^3 is modeled. This corresponds to the active RCS volume taking into account 10-percent uniform SGTP minus the pressurizer and the reactor vessel upper head.
- The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of HZP, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1550 ppm, corresponding to the HZP, all rods inserted (minus the most reactive RCCA), and no xenon condition. The 250-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.2.3 Dilution during Full-Power Operation

In this mode, the plant can be operated in either automatic or manual rod control. Conditions assumed for the analysis were:

- Dilution flow is at the maximum capacity of the charging pumps—294 gpm.
- A minimum RCS water volume of 9350 ft^3 is modeled. This corresponds to the active RCS volume (with 10-percent uniform SGTP) minus the pressurizer and reactor vessel upper head.
- The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of HFP, rods to insertion limits, and no xenon.
- The critical boron concentration following reactor trip is assumed to be 1450 ppm, corresponding to the HZP, all rods inserted (minus the most reactive RCCA), and no xenon condition. The 350-ppm change from the initial condition noted above is a conservative minimum value.

6.3.5.3 Description of Analysis

To cover all phases of plant operation, boron dilution during refueling and power modes of operation were considered in this analysis.

Conservative values for necessary parameters were used, that is, high RCS critical boron concentrations, high boron worth, minimum shutdown margins, and lower than actual RCS volumes. These assumptions result in conservative determinations of the time available for operator or system response after detection of a dilution transient in progress.

Conservative analysis methods were used to analyze a CVCS malfunction that resulted in a decrease in boron concentration in the reactor coolant. Minimum reactor coolant volumes and maximum dilution flow rates were conservatively assumed for each case analyzed. The result was a logarithmic decrease in coolant boron concentration according to the equation:

$$dC_B/dt = -\ [Q_{in}/V]\ C_B$$

Where:

C_B = Boron concentration in the RCS

Q_{in} = Maximum dilution flow rate

V = Active volume in RCS

This equation is solved for the time at which the core would become critical or all shutdown margin would be lost. The rate of reactivity insertion due to the dilution is calculated from the dilution rate and the differential boron worth. The results of this analysis were conservative for all cases analyzed.

6.3.5.4 Acceptance Criteria

A CVCS malfunction is classified as an ANS Condition II event, a fault of moderate frequency. Criteria established for Condition II events are as follows.

- The critical heat flux should not be exceeded. This is ensured by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.
- Fuel temperature and fuel clad strain limits should not be exceeded. The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

This event was analyzed to ensure that there is sufficient time for mitigation of an inadvertent boron dilution prior to the complete-loss-of-shutdown margin. A complete-loss-of-plant-shutdown margin results in a return of the core to the critical condition, causing an increase in the RCS temperature and heat flux. This could violate the safety analysis DNBR limit and challenge fuel and fuel cladding integrity. A complete-loss-of-plant-shutdown margin could also result in an increase in RCS pressure. This could challenge the pressure design limit for the RCS.

If the minimum allowable shutdown margin is shown not to be lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other Condition II transients. By showing that the above criteria were met for those Condition II events, it can be concluded that they were also met for the boron dilution event. Operator action was relied upon to preclude a complete-loss-of-plant-shutdown margin.

Per the current IP3 licensing basis, the minimum times required in order to credit operator action for this event are:

- Refueling: There must be at least 30 minutes between initiation of the event and the time at which plant shutdown margin is lost.
- Startup: There must be at least 15 minutes between initiation of the event and the time at which plant shutdown margin is lost.
- Power Operation: There must be at least 15 minutes between the time of alarm and the time at which plant shutdown margin is lost.

6.3.5.5 Results

6.3.5.5.1 Dilution during Refueling

From initiation of the event, there were 31.74 minutes available for operator action prior to return to criticality.

6.3.5.5.2 Dilution during Startup

From initiation of the event, there were 26.48 minutes available for operator action prior to return to criticality.

6.3.5.5.3 Dilution during Full-Power Operation

From time of alarm while in manual rod control, there were 34.82 minutes available for operator action prior to loss-of-shutdown margin (return to criticality).

From time of alarm while in automatic rod control, there were 36.92 minutes available for operator action prior to loss-of-shutdown margin (return to criticality).

6.3.5.6 Conclusions

The results of this analysis show that in the event of an uncontrolled inadvertent boron dilution, there is sufficient time for operator action to mitigate the consequences of this event prior to a complete-loss-of-shutdown margin, as demonstrated in Table 6.3-18. Therefore, the applicable acceptance criteria are met.

6.3.6 Loss-of-External Electrical Load

6.3.6.1 Introduction

A major loss-of-load (LOL) can result from either a loss-of-external-electrical load or from a turbine trip. A loss-of-external-electrical load can result from an abnormal variation in network frequency or other adverse network operating conditions. For either case, offsite power is available for the continued operation of plant components such as the RCPs. The case of loss-of-all-non-emergency-AC power is presented in subsection 6.3.8 of this document.

For a loss-of-external-electrical load without subsequent turbine trip, no direct reactor trip signal would be generated, as the plant would be expected to trip from the reactor protection system if a safety limit were approached. A continued steam load of approximately 5 percent would exist after total loss-of-external-electrical load because of the steam demand of plant auxiliaries.

For a turbine trip, the reactor would be tripped directly (unless below P-8 power) on a signal from the turbine auto stop oil pressure or turbine stop valves.

If the steam dump valves fail to open following a large LOL, the steam generator safety valves can lift and the reactor can be tripped by the high-pressurizer pressure signal, high-pressurizer water level signal, or OTΔT signal. If feedwater flow is also lost, the reactor can be tripped by a steam generator low-low water level signal. The steam generator shell-side pressure and reactor coolant temperatures will increase rapidly following a large LOL. The pressurizer and steam generator safety valves are sized to protect the RCS and steam generators against overpressure for all load losses without assuming operation of the Steam Dump

System, pressurizer spray, pressurizer PORVs, automatic rod control, or direct reactor trip on turbine trip.

The PSV capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the steam generator safety valves. The pressurizer and steam generator safety valves are then able to maintain the RCS and MSS pressures within 110 percent of the corresponding design pressure without a direct reactor trip on turbine trip.

6.3.6.2 Input Parameters and Assumptions

The loss-of-external electrical load/turbine trip accident is analyzed for three specific cases:

- Maximum RCS and secondary side pressures
- Minimum DNBR

The major assumptions used in the analyses are summarized below.

Initial Operating Conditions

The peak pressure cases are analyzed using the STDP. Initial reactor power and RCS temperatures are assumed to be at their nominal values plus uncertainties. Initial RCS pressure is assumed to be at its nominal value minus uncertainties. The analysis models thermal design flow (354,400 gpm).

The minimum DNBR case with pressure control is analyzed using the RTDP (Reference 3). Initial reactor power, pressure, and RCS average temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the DNBR limit. Minimum measured flow (364,700 gpm) is modeled.

Reactivity Coefficients

Minimum reactivity feedback (BOL) conditions are conservatively assumed for both cases. The analysis is performed at full-power conditions assuming an MTC of 0 pcm/°F. Least negative Doppler coefficients are also assumed.

Reactor Control

From the standpoint of the maximum pressures and minimum DNBR attained, it is conservative to assume that the reactor is in manual rod control. If the reactor were in automatic rod control, the control rod banks would insert prior to trip and reduce the severity of the transient.

Pressurizer Spray and PORVs

The pressurizer PORVs and pressurizer spray portion of the automatic pressure control system are assumed in the minimum DNBR and peak secondary side pressure cases since each serves to limit the RCS pressure increase, which is conservative for the DNBR and secondary side pressure calculations. In the peak RCS pressure case, the pressurizer PORVs and spray are assumed not to be available. In each case, safety valves are assumed operable with a capacity of 420,000 lbm/hr per valve for three valves.

Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for AFW flow; however, eventually AFW flow would be initiated and a stabilized plant condition would be reached.

Reactor Trip

Reactor trip is actuated by the first RPS trip setpoint reached. Trip signals are expected due to high-pressurizer pressure, low-low steam generator level, and OTΔT.

Steam Release

No credit is taken for operation of the Steam Dump System or steam generator atmospheric relief valves (ARVs). This assumption maximizes secondary pressure.

6.3.6.3 Description of Analysis

For the loss-of-external-electrical-load/turbine-trip event, the behavior of the unit is analyzed for a complete loss-of-steam load from full power without a direct reactor trip. This assumption is made to show the adequacy of the pressure-relieving devices and to demonstrate core protection margins by delaying reactor trip until conditions in the RCS result in a trip due to other signals. Thus, the analysis assumes a worst-case transient. In addition, no credit is taken for steam dump. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for AFW (except for long-term recovery) to mitigate the consequences of the transient.

A detailed analysis using the RETRAN (Reference 1) computer code was performed to determine the plant transient conditions following a total loss of load. The code models the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and spray, steam generators, MSSVs, and the Auxiliary Feedwater System (AFWS); and computes pertinent variables, including pressurizer pressure, steam generator pressure, steam generator mass, and reactor coolant average temperature.

6.3.6.4 Acceptance Criteria

Based on its frequency of occurrence, the loss-of-external-electrical-load/turbine-trip accident is considered a Condition II event as defined by the ANS. The criteria are as follows.

- Pressure in the RCS and MSS shall remain below 110 percent of the design values.
- Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit.
- An incident of moderate frequency shall not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition, the potential for damage to the PSVs due to water relief is precluded and the RCS pressure boundary is uncompromised (that is, the Condition II event will not progress into a Condition III or IV type event).
- An incident of moderate frequency in combination with any single active component failure, or single operator error, shall be considered an event for which an estimate of the number of potential fuel failures shall be provided for radiological dose calculations. For such accidents, fuel failure must be assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model, that fewer failures occur. There shall be no loss of function of any fission product barrier other than the fuel cladding.

6.3.6.5 Results

The calculated sequence of events for the loss-of-external-electrical-load/turbine-trip cases are presented in Table 6.3-6.

Peak Pressure Cases

The transient responses for the total loss of steam load from full power are shown in Figures 6.3-33 through 6.3-36 for the peak RCS pressure case. No credit is taken for the pressurizer spray, pressurizer PORVs, or for the steam dump. The reactor is tripped by the

high-pressurizer pressure trip channel. The PSVs are actuated and the primary system pressure remains below the 110-percent design value. In the peak secondary side pressure case, full credit is taken for the pressurizer spray and pressurizer PORVs, but no credit is taken for the steam dump. The reactor is tripped by the OTΔT reactor trip channel. The steam generator safety valves maintain the secondary side steam pressure below 110 percent of the steam generator shell design pressure. The peak primary system and secondary side steam pressures and the corresponding design pressures are presented in Table 6.3-18.

Minimum DNBR Case

The transient responses for the total loss of steam load from full power are shown in Figures 6.3-37 through 6.3-40. Full credit is taken for the pressurizer spray and pressurizer PORVs. No credit is taken for the steam dump. The reactor is tripped by the OTΔT reactor trip channel. The minimum DNBR remains well above the limit value, as demonstrated in Table 6.3-18.

6.3.6.6 Conclusions

The results of this analysis show that the plant design is such that a total loss-of-external-electrical-load transient without a direct reactor trip presents no hazard to the integrity of the RCS or the MSS at SPU conditions. All of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the safety analysis limit value. The peak primary and secondary system pressures remain below 110 percent of design at all times. The protection features presented in subsection 6.3.6.3 provide mitigation of the loss-of-external-electrical-load/turbine-trip transient so that the above criteria are satisfied.

6.3.7 Loss-of-Normal Feedwater

6.3.7.1 Introduction

An LONF (from pump failures, valve malfunctions, or LOAC) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If the reactor were not tripped during this accident, fuel damage would possibly occur as a result of the loss-of-heat sink while at power. If an alternative supply of feedwater is not supplied to the plant, residual heat following a reactor trip may heat the primary system water to the point where water relief from the pressurizer could occur. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised. Since a reactor trip occurs well before the steam generator heat transfer capability is reduced, the primary system conditions never approach those that would result in a DNB condition.

The LONF that occurs as a result of the LOAC power is discussed in subsection 6.3.8 of this report.

The following events occur after the reactor trip for the LONF resulting from main feedwater pump failures or valve malfunctions:

- As steam system pressure rises following the trip, the steam generator atmospheric relief valves (ARVs) can be automatically opened. Steam dump to the condenser is assumed not available. If the steam generator ARVs are not available, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor core.

- As the no-load temperature is approached, the steam generator ARVs (or the MSSVs, if the steam generator ARVs are not available) are used to dissipate the residual decay heat and RCP heat and to maintain the plant at the hot standby condition.

Following the occurrence of an LONF, the reactor can be tripped on any of the following RPS trip signals:

- Low-low water level in any steam generator
- OTΔT
- High-pressurizer pressure
- High-pressurizer water level
- RCP undervoltage (if coincident with a LOOP signal)
- Steam flow-feedwater flow mismatch in coincidence with low water level in any steam generator

AFW is supplied by the actuation of two motor-driven AFW pumps (MDAFWPs), which are initiated by any of the following signals:

- Low-low water level in any steam generator
- Automatic trip (not manual) of any main feedwater pump turbine
- Any safety injection (SI) signal
- Manual actuation
- LOOP concurrent with unit trip

In addition, one turbine-driven AFW pump (TDAFWP) starts on any of the following actuation signals, although no automatic delivery of water to the steam generators occurs (the TDAFWP is automatically started, but must be manually aligned by the operator to allow delivery of AFW flow to the steam generators).

- Low-low water level in any two steam generators
- Loss-of-offsite power (LOOP) concurrent with unit trip and no SI signal
- Manual actuation

The MDAFWPs are powered by the emergency diesel generators (EDGs). The pumps take suction from the condensate storage tank (CST) for delivery to the steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal. The TDAFWP is valved out during normal operation. Therefore, although the TDAFWP is automatically actuated, this pump is not available to deliver flow to the steam generators until operator action is taken to align the TDAFWP.

Backup in equipment and control logic is provided to ensure that reactor trip and automatic AFW flow will occur following any LONF, including that followed by a LOAC. The analysis shows that following a LONF, the AFWS is capable of removing the stored and residual heat plus RCP heat, thus preventing overpressurization of the RCS and the steam generator secondary side, water relief from the pressurizer, and uncovery of the reactor core.

6.3.7.2 Input Parameters and Assumptions

The analysis was performed for IP3 at SPU conditions. The major assumptions used in this analysis were as follows.

- The plant is initially operating at 102 percent of the uprated NSSS power (3230 MWt) and bounds a nominal pump heat of 14 MWt.

- The RCPs are assumed to operate continuously throughout the transient providing a constant reactor coolant volumetric flow equal to the thermal design flow (TDF).

- Cases were considered assuming initial HFP T_{avg} at the upper and lower ends of the SPU operating range with uncertainty applied in both the positive and negative direction. The vessel average temperature assumed at the upper end of the range is 572°F with an uncertainty of ±7.5°F. The average temperature assumed at the lower end of the range is 549°F with an uncertainty of ±7.5°F. For each case, the initial pressurizer level is at the nominal programmed level plus 8.5-percent span.

- Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±60 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound potential operating conditions.

- Cases are analyzed assuming initial feedwater temperatures at the upper and lower ends of the uprated operating feedwater temperature window (433.6°F and 390°F, respectively).

- Reactor trip occurs on steam generator low-low water level at 0-percent narrow range span (NRS).

- The worst single failure modeled in the analysis is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 343 gpm, distributed equally between two of the four steam generators. 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. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal.

- The automatic AFW flow is assumed to be initiated 60 seconds following a low-low steam generator water level signal.

- The pressurizer spray, PORVs, and heaters are assumed to be operable to maximize the pressurizer water volume. Note that these control systems are not required for event mitigation since the PSVs alone would prevent the RCS pressure from exceeding the design limit during this transient.

- Secondary system steam relief is achieved through the MSSVs, which are modeled assuming a +3-percent lift setpoint tolerance, a 5-psi ramp for the valve to pop open, and a pressure difference between each steam generator and the safety valves of approximately 20 psi at full relief flow. Steam relief through the steam generator ARVs and condenser dump valves is assumed unavailable.

- A conservative core decay heat generation based upon long-term operation at the initial power level preceding the trip is assumed. This core decay heat generation model is based on the 1979 version of ANS 5.1 (Reference 9) and includes a 2σ uncertainty. ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

- Analysis with both minimum (0 percent) and maximum (10 percent) SGTP is performed to conservatively bound potential operating conditions. In all cases, a nominal steam generator level plus a bounding uncertainty of 10-percent NRS was considered.

- A maximum AFW enthalpy of 90.77 Btu/lbm is conservatively assumed. An AFW line purge volume of 268.8 ft^3 is modeled.

6.3.7.3 Description of Analysis

A detailed analysis using the RETRAN (Reference 1) computer code was performed to determine the plant transient following a loss-of-normal feedwater. The code simulates the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and safety valves, pressurizer heaters and spray, steam generators, MSSVs, and the AFWS, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

6.3.7.4 Acceptance Criteria

Based on its frequency of occurrence, the LONF accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event.

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met. With respect to DNB, the LONF accident is bounded by the LOL accident described in subsection 6.3.6. Both of these events represent a reduction in the heat removal capability of the secondary system. For the LONF event, the RCS temperature increases gradually as the steam generators boil down to the low-low level trip setpoint, at which time reactor trip occurs, followed by turbine trip. For the LOL event, the turbine trip is the initiating event, and the loss-of-heat sink is much more severe. Therefore, the initial RCS heatup will be much more severe for the loss-of-load event than for the LONF event, and the LOL event will always be more severe with respect to the minimum DNBR criterion.

- Pressure in the RCS and MSS shall be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the LONF accident is bounded by the loss-of-load accident reported in subsection 6.3.6. For the loss-of-normal-feedwater event, turbine trip occurs after reactor trip, whereas for the loss-of-load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL than for the LONF.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised (that is, the Condition II event will not progress into a Condition III or IV type event).

6.3.7.5 Results

The calculated sequence of events for this accident is listed in Table 6.3-7. Figures 6.3-41 through 6.3-49 present the transient response of plant conditions and parameters of interest following a LONF with the assumptions listed in subsection 6.3.7.2 of this document. It should be noted that the transient is initiated following a 20-second steady-state.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to reduction of the steam generator void fraction and because steam flow through the MSSVs continues to dissipate the stored and generated heat. Approximately 1 minute following the initiation of the low-low steam generator water level trip, one MDAFWP starts automatically, consequently reducing the rate at which the steam generator water level decreases in the two steam generators receiving automatic AFW flow. Operator action to start the second MDAFWP or to align the TDAFWP at 10 minutes after reactor trip on a low-low steam generator water level signal is assumed to deliver additional AFW flow to the two steam generators not already receiving AFW and the plant is brought to a stable condition.

The pressurizer never reaches a water-solid condition, as demonstrated in Table 6.3-18 (see Figure 6.3-42). Hence, no water relief from the pressurizer occurs.

Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

6.3.7.6 Conclusions

With respect to DNB, the LONF accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the minimum DNBR remains greater than the safety analysis limit.

With respect to RCS and MSS pressurization, the LONF accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the RCS and MSS pressure limits are met.

The results of the analysis show that the pressurizer does not reach a water-solid condition and therefore, the LONF event does not adversely affect the core, RCS, or MSS.

6.3.8 LOAC to the Station Auxiliaries

6.3.8.1 Introduction

A complete loss-of-non-emergency-AC power can result in the loss-of-all-power to the plant auxiliaries, such as the RCPs and condensate pumps. The loss-of-power to the condensate pumps results in a LONF. The loss of power may be caused by a complete loss-of-the-offsite grid accompanied by a turbine generator trip at the station, or by a loss-of-the-onsite AC (LOAC) distribution system.

The first few seconds of the transient would be almost identical to the complete loss-of-flow accident presented later in subsection 6.3.13, in which the pump coastdown inertia along with the reactor trip prevents reaching the DNBR limit. After the trip, decay heat removal will be accommodated by the AFWS. This portion of the transient would be similar to that presented in subsection 6.3.7 for the LONF event.

Following a LOAC with turbine and reactor trips, the sequence described below will occur.

- Plant vital instruments are supplied from emergency DC power sources.
- As the steam system pressure rises following the trip, the steam generator ARVs can be automatically opened to atmosphere. The condenser is assumed not available for steam dump because of the loss-of-the-circulating water pumps. If the steam generator ARVs are not available, the MSSVs can lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.
- As the no-load temperature is approached, the steam generator ARVs (or the MSSVs, if the steam generator ARVs are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot standby condition.
- The EDGs will start on a loss-of-voltage on the plant emergency buses and begin to supply plant vital loads.

The AFWS is started automatically as discussed previously in subsection 6.3.7 for the LONF analysis. The AFWS comprises two MDAFWPs and 1 TDAFWP. The TDAFWP uses steam from the secondary system and exhausts the steam to the atmosphere. The two MDAFWPs are supplied by power from the EDGs and take suction directly from the CST for delivery to the

steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal, even if a loss of all non-emergency-AC power occurs simultaneously with a LONF. The TDAFWP is started automatically. However, the TDAFWP needs to be manually aligned before AFW flow can be delivered to the steam generators.

Following the loss-of-power to the RCPs, the RCPs coast down and the removal of residual decay heat is provided by natural circulation in the RCS, supported by AFW flow to the secondary system. Demonstrating that acceptable results can be obtained for this event shows that the natural circulation flow in the RCS is adequate to remove decay heat from the core.

The analysis of the LOAC event is performed to demonstrate that natural circulation in the RCS, along with the AFWS, is capable of removing the stored and residual decay heat from the core, and consequently preventing RCS or MSS overpressurization, water relief from the pressurizer, and uncovery of the reactor core.

6.3.8.2 Input Parameters and Assumptions

The analysis was performed for IP3 at SPU conditions. The major assumptions used in this analysis were as follows.

- The plant is initially operating at 102 percent of the uprated NSSS power (3230 MWt). A conservative RCP heat was assumed for the period of the event prior to the tripping of the RCPs.

- The initiating event is a loss-of-all-non-emergency-AC power that results in a loss-of-power to the condensate pumps. The loss of the condensate pumps results in a LONF.

- The RCPs are conservatively assumed to operate until the time of reactor trip, providing a constant reactor coolant volumetric flow equal to the TDF value. This assumption maximizes the amount of stored energy in the RCS. The loss-of-power to the RCPs is not assumed to occur until 2 seconds after the start of rod motion following the reactor trip on a low-low steam generator water level condition.

- No credit is taken for the immediate insertion of the control rods due to the LOAC to the station auxiliaries.

- Cases were considered assuming initial HFP T_{avg} at the upper and lower ends of the SPU operating range with uncertainty applied in both the positive and negative direction. The vessel average temperature assumed at the upper end of the range is 572°F with an uncertainty of ±7.5°F. The average temperature assumed at the lower end of the range is 549°F with an uncertainty of ±7.5°F. For each case, the initial pressurizer level is at the nominal programmed level plus 8.5-percent span.

- Initial pressurizer pressure is assumed to be 2250 psia with an uncertainty of ±60 psi. Cases are considered with the pressure uncertainty applied in both the positive and negative direction to conservatively bound potential operating conditions.

- Cases are analyzed assuming initial feedwater temperatures at the upper and lower ends of the uprated operating feedwater temperature window (433.6 and 390°F, respectively).

- Reactor trip occurs on steam generator low-low water level at 0 percent of NRS.

- The worst single failure modeled in the analysis is the loss of one of the two MDAFWPs. This results in the availability of only one MDAFWP automatically supplying a minimum total AFW flow of 343 gpm, distributed equally between two of the four steam generators. 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. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal.

- The automatic AFW flow is assumed to be initiated 60 seconds after a low-low steam generator water level signal.

- The pressurizer spray, PORVs, and heaters are assumed to be operable to maximize the pressurizer water volume. Note that these control systems are not required for event mitigation since the PSVs alone would prevent the RCS pressure from exceeding the design limit during this transient.

- Secondary system steam relief is achieved through the MSSVs, which are modeled assuming a +3 percent lift setpoint tolerance, a 5-psi ramp for the valve to pop open, and a pressure difference between each steam generator and the safety valves of approximately 20 psi at full relief flow. Steam relief through the steam generator ARVs or condenser dump valves is assumed unavailable.

- A conservative core decay heat generation based upon long term operation at the initial power level preceding the trip is assumed. This core decay heat generation model is based on the 1979 version of ANS 5.1 (Reference 9) and includes a 2σ uncertainty. ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates.

- Analysis with both minimum (0 percent) and maximum (10 percent) SGTP is performed to conservatively bound potential operating conditions. In all cases, a nominal steam generator level plus a bounding uncertainty of 10-percent NRS was considered.

- A maximum AFW enthalpy of 90.77 Btu/lbm is conservatively assumed. An AFW line purge volume of 268.8 ft^3 is modeled.

6.3.8.3 Description of Analysis

A detailed analysis using the RETRAN (Reference 1) computer code was performed to determine the plant transient following a LOAC. The code simulates the core neutron kinetics, RCS including natural circulation, pressurizer, pressurizer PORVs and safety valves, pressurizer heaters and spray, steam generators, MSSVs, and the AFWS, and computes pertinent variables, including pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

6.3.8.4 Acceptance Criteria

Based on its frequency of occurrence, the loss-of-non-emergency-AC-power accident is considered a Condition II event as defined by the ANS. The following items summarize the acceptance criteria associated with this event.

- The critical heat flux shall not be exceeded. This is demonstrated by ensuring that the applicable safety analysis DNBR limit is met. With respect to DNB, the loss-of-non-emergency-AC-power accident is bounded by the complete loss-of-flow accident reported in subsection 6.3.13. The DNBR consequences of the loss-of-non-emergency-AC-power event are similar to those of the LONF event, with the additional effect of a reduction in the core flow rate caused by loss-of-power to the RCPs. However, the loss-of-non-emergency-AC-power event remains bounded by the complete-loss-of-flow event. This is because the RCP coastdown is the initiating fault and the reactor trip occurs when the core flow is already degraded.

- Pressure in the RCS and MSS shall be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the loss-of-non-emergency-AC-power accident is bounded by the loss-of-load accident reported earlier in subsection 6.3.6. For the loss-of-non-emergency-AC-power event, turbine trip occurs after reactor trip, whereas for loss-of-load the turbine trip is the initiating fault. Therefore, the primary/secondary power mismatch and resultant RCS and MSS heatup and pressurization transients are always more severe for the LOL than the loss-of-non-emergency-AC-power.

- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently. This criterion is met by ensuring that the pressurizer does not reach a water-solid condition. By precluding a water-solid condition in the pressurizer, the potential for damage to the pressurizer PORVs and safety valves due to water relief is precluded and the RCS pressure boundary is not compromised (that is, the Condition II event will not progress into a Condition III or IV type event).

6.3.8.5 Results

Figures 6.3-50 through 6.3-58 present the transient response of plant conditions and parameters of interest following a loss of non-emergency AC power with the assumptions listed earlier in subsection 6.3.8.2. The calculated sequence of events for this accident is listed in Table 6.3-8. It should be noted that the transient is initiated following a 20-second steady-state.

During the first few seconds after the loss-of-non-emergency-AC power to the RCPs, the RCS flow transient closely resembles the complete loss-of-flow incident, where core damage due to rapidly increasing core temperature is prevented by reactor trip, which, for a loss-of-non-emergency-AC-power event, is on a low-low steam generator water level signal. After reactor trip, stored and residual decay heat must be removed to prevent damage to the core and the RCS and MSS. The RETRAN code results show that natural circulation and the AFW flow available are sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

The pressurizer never reaches a water-solid condition, as demonstrated in Table 6.3-18 (see Figure 6.3-51). Hence, no water relief from the pressurizer occurs.

6.3.8.6 Conclusions

With respect to DNB, the loss-of-non-emergency-AC-power event is bounded by the complete-loss-of-flow event (see subsection 6.3.13), demonstrating that the minimum DNBR remains above the safety analysis limit.

With respect to RCS and MSS pressurization, the loss-of-non-emergency-AC-power accident is bounded by the LOL accident (see subsection 6.3.6), which demonstrates that the RCS and MSS pressure limits are met.

The results of the analysis show that the pressurizer does not reach a water-solid condition and therefore, the LOAC does not adversely affect the core, the RCS, or the MSS.

6.3.9 Excessive Heat Removal Due to Feedwater System Malfunctions

6.3.9.1 Introduction

Reductions in feedwater temperature or excessive feedwater additions are a means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the RCS and the secondary side of the plant. The overpower/overtemperature protection functions (neutron high flux, OTΔT, and OPΔT trips) prevent any power increase that could lead to a DNBR that is less than the safety analysis limit value.

An example of excessive feedwater flow would be a full opening of one feedwater control valve due to a Feedwater Control System malfunction or an operator error. At power, this excess flow causes a greater load demand on the RCS due to increased subcooling in the steam generator. With the plant at no-load conditions, the addition of cold feedwater can cause a decrease in RCS temperature and thus, a positive reactivity insertion due to the effects of the negative MTC of reactivity. Continuous excessive feedwater addition is prevented by the steam generator high-high water level trip.

A second example of excess heat removal is the transient associated with failure of the low-pressure heaters' bypass valve resulting in an immediate reduction in feedwater temperature. At power, this increased subcooling will create a greater load demand on the RCS. However, the low-pressure feedwater bypass valve is not in service. Thus, this event is no longer credible and was not considered here.

6.3.9.2 Input Parameters and Assumptions

The reactivity insertion rate following a feedwater system malfunction, attributed to the cooldown of the RCS, was calculated with the following assumptions:

- This accident is analyzed with the RTDP as described in WCAP-11397 (Reference 3). Initial reactor power, RCS pressure, and RCS temperature are assumed to be at their nominal values, adjusted to account for any applicable measurement biases, consistent with steady-state, full-power operation. Minimum measured flow (MMF) is modeled. Uncertainties in initial conditions are included in the DNBR limit as described in WCAP-11397 (Reference 3).

- The analyses are done at the uprated NSSS power level of 3230 MWt.

- For the feedwater control valve accident at full-power conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction, resulting in a step increase to 143 percent of the nominal full-power feedwater flow to one steam generator.

- The increase in feedwater flow rate results in a decrease in the feedwater temperature due to the reduced efficiency of the feedwater heaters. For the HFP cases, a 20°F decrease in the feedwater temperature is assumed to occur coincident with the feedwater flow increase.

- For the feedwater control valve accident at zero-load conditions that results in an increase in feedwater flow to one steam generator, one feedwater control valve is assumed to malfunction, resulting in a step increase to 210 percent of the nominal full-load value for one steam generator.

- For cases at zero-load conditions, feedwater temperature is assumed to be 70°F.

- The initial water level in all the steam generators is a conservatively low level; 35-percent NRS for full-power conditions and 45-percent NRS for zero-power conditions.

- No credit is taken for the heat capacity of the RCS and steam generator metal mass in attenuating the resulting plant cooldown.

- The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal that closes all feedwater main control and feedwater control-bypass valves, indirectly closes all feedwater pump discharge valves, and trips the main feedwater pumps and turbine generator.

The RPS features, including power-range high neutron flux, OTΔT, and turbine trip on high-high steam generator water level, are available to provide mitigation of the feedwater system malfunction transient.

Normal reactor control systems and engineered safety systems (for example, SI) are not assumed to function. The RPS can actuate to trip the reactor due to an overpower condition. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.3.9.3 Description of Analysis

The excessive heat removal due to a feedwater system malfunction transient was analyzed with the RETRAN (Reference 1) computer code. This code simulates a multi-loop system, neutron kinetics, the pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The code computed pertinent plant variables including temperatures, pressures, and power level.

The excessive-feedwater-flow event assumed an accidental opening of one feedwater control valve with the reactor at both full- and zero-power conditions with both automatic and manual rod control. Both the automatic and manual rod control cases assumed a conservatively large moderator density coefficient characteristic of EOL conditions.

6.3.9.4 Acceptance Criteria

Based on its frequency of occurrence, the feedwater-system-malfunction event is considered a Condition II event as defined by the ANS. Even though DNB is the primary concern in the analysis of the feedwater malfunction event, the following three items summarize the criteria associated with this transient:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the limit value at any time during the transient.
- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures.
- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt.

6.3.9.5 Results

The excessive-feedwater-flow full-power case with automatic rod control yielded results that were nearly identical to the case assuming manual rod control. Considering cases with and without automatic rod control and presenting the more limiting results demonstrated that the Rod Control System was not required to function for this event. A turbine trip, which resulted in a reactor trip, was actuated when the steam generator water level in the affected steam generator reached the high-high water level setpoint. The results presented are for the case that assumes the Rod Control System was in manual operational mode.

The case initiated at HZP conditions assumed manual rod control and was less limiting than the HZP steamline break analysis. Therefore, the results of the HZP case are not presented.

For all cases of excessive feedwater flow, continuous addition of cold feedwater was prevented by automatic closure of all feedwater control and isolation valves, closure of all feedwater bypass valves, a trip of the feedwater pumps, and a turbine trip on high-high steam generator water level. In addition, the feedwater pump discharge isolation valves will automatically close upon receipt of the feedwater pump trip signal.

Following turbine trip, the reactor will automatically be tripped, either directly due to the turbine trip or due to one of the reactor trip signals discussed in subsection 6.3.6 (loss-of-external-electrical-load and/or turbine trip). With the reactor in automatic rod control, the control rods would be inserted at the maximum rate following the turbine trip, and the resulting transient would not be limiting in terms of peak RCS pressure.

The effects of the RTDP methodology, including Rod Control System response characteristics were incorporated into the analysis. Table 6.3-9 shows the time sequence of events for the HFP feedwater malfunction transient. Figures 6.3-59 through 6.3-62 show transient responses for various system parameters during a feedwater system malfunction initiated from HFP conditions with manual rod control. The minimum DNBR remains above the safety analysis limit at all times, as demonstrated in Table 6.3-18.

6.3.9.6 Conclusions

For the excessive-feedwater-addition-at-power transient, the results showed that the DNBRs encountered were above the limit value; hence, no fuel damage was predicted.

The protection features presented previously in subsection 6.3.9.2 provided mitigation of the feedwater-system-malfunction transient so that the above criteria were satisfied.

6.3.10 Excessive Load Increase Incident

6.3.10.1 Introduction

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 steam generator 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 control systems in automatic. Any loading rate in excess of these values can cause a reactor trip actuated by the RPS.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control. For excessive loading by the operator or by system demand, the turbine load limiter keeps the maximum turbine load at 100-percent rated load.

During power operation, steam dump to the condenser is controlled by comparing the RCS temperature (nominal T_{avg}) to a reference temperature based on turbine power, where a high temperature difference in conjunction with a loss of load or a turbine trip indicates a need for steam dump. A single controller or control signal malfunction does not cause steam dump valves to open. Interlocks are provided to block the opening of the valves unless a large turbine load decrease or a turbine trip has occurred. In addition, the reference temperature and LOL signals are developed by independent sensors.

Protection against an excessive load increase accident is provided by the following RPS signals:

- OPΔT
- OTΔT
- Power range high neutron flux
- Low-pressurizer pressure

6.3.10.2 Input Parameters and Assumptions

The analysis includes the following conservative assumptions:

- This event is evaluated with the RTDP (Reference 3). Initial reactor power and RCS pressure and temperature are assumed to be at their nominal values. Uncertainties in initial conditions are included in the limit DNBR as described in WCAP-11397-P-A (Reference 3).

- The evaluation is performed for a step-load increase of 10-percent steam flow from 100-percent RTP.

- The excessive load increase event is evaluated for both BOL (minimum reactivity feedback) and EOL (maximum reactivity feedback) conditions.

6.3.10.3 Description of Analysis

Four cases were considered to demonstrate that the fuel cladding integrity will not be adversely affected following a 10-percent step-load increase from rated load. This was shown by demonstrating that the minimum DNBR would not go below the safety analysis limit value.

- Manually controlled reactor with BOL (minimum moderator) reactivity feedback
- Manually controlled reactor with EOL (maximum moderator) reactivity feedback
- Automatically controlled reactor with BOL (minimum moderator) reactivity feedback
- Automatically controlled reactor with EOL (maximum moderator) reactivity feedback

At BOL minimum moderator feedback conditions, the core had the least-negative MTC of reactivity and the least-negative Doppler-only power coefficient curve, and therefore, the least-inherent transient response capability. Since a positive MTC would provide a transient benefit, a zero MTC was evaluated for the minimum feedback conditions. For the EOL maximum moderator feedback conditions, the MTC of reactivity had its most-negative value and the most-negative Doppler-only power coefficient curve. This resulted in the largest amount of reactivity feedback due to changes in coolant temperature.

The effect of this transient on the minimum DNBR was evaluated by applying conservatively large deviations to the initial conditions of core power, average coolant temperature, and pressurizer pressure at the normal full-power operating conditions to generate a limiting set of statepoints. These deviations bound the variations that could occur as a result of an excessive load increase accident and were only applied in the direction that had the most adverse effect on the DNB ratio; namely increased power, coolant temperature, and decreased pressure. No credit was taken for the decrease in coolant temperature and no reactor trip is assumed.

The reactor condition statepoints (temperature, pressure, and power) were compared to the conditions corresponding to operation at the safety analysis DNB limit.

Normal reactor control systems and engineered safety systems were not required to function. A conservative limit on the turbine valve opening was assumed. The analysis did not take credit for pressurizer heaters.

The RPS was assumed to be operable. However, reactor trip was not encountered for most cases due to the error allowances assumed in the setpoints. No single active failure in any system or component required for mitigation will adversely affect the consequences of this accident.

6.3.10.4 Acceptance Criteria

Based on its frequency of occurrence, the excessive load increase event is considered a Condition II event as defined by the ANS. Even though DNB is the primary concern in the evaluation of the excessive load increase, the following three items summarize the criteria associated with this transient:

- The critical heat flux should not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.

- Pressure in the RCS and MSS should be maintained below 110 percent of the design pressures. With respect to RCS and MSS overpressurization, the excessive load increase incident is bounded by the loss-of-load accident reported earlier in subsection 6.3.6. Although RCS pressure may increase slightly for excessive load increase cases with automatic rod control, the pressurizer PORVs would have sufficient capacity to limit pressurization at or very near the opening setpoint. If the pressurizer PORVs were not available and pressure continued to rise, the pressurizer safety valves would have more than enough capacity to limit further pressurization significantly above the valve opening pressure. Steam generator pressure decreases as a result of the excessive load increase incident and therefore MSS overpressurization is not a concern.

- The peak linear heat generation rate should not exceed a value that would cause fuel centerline melt. The overpower limit (120-percent) is also not violated during the excessive load increase incident, as a 10-percent mismatch in primary/secondary load does not cause a 20-percent increase in core power, even with a conservative rod control model.

6.3.10.5 Results

An excessive load increase accident of the magnitude considered here does not result in reactor trip, and the plant soon reaches a new equilibrium condition at a higher power level based on the increased steam load. Transients assuming manual rod control yield decreased coolant temperatures and pressures resulting from increased heat removal.

A comparison of the plant conditions assuming conservatively bounding deviations in core power, average coolant temperature, and pressure to the conditions corresponding to operation at the safety analysis DNB limit indicated that the minimum DNBR remained above the limit value for each of the cases, as demonstrated in Table 6.3-18.

RCS and MSS overpressurization are not a concern for this transient.

6.3.10.6 Conclusions

It has been demonstrated that for an excessive load increase, the minimum DNBR during the transient will not go below the safety analysis limit value and thus will neither affect fuel cladding integrity nor result in the release of fission products to the RCS.

6.3.11 Rupture of a Steam Pipe

6.3.11.1 Introduction

A steam pipe rupture is assumed to include any accident that results in an uncontrolled steam release from a steam generator. The release can occur as a result of a break in a pipe line or a valve malfunction. The steam release results in an initial increase in steam flow that decreases during the accident as the steam pressure falls. The removal of energy from the RCS causes a reduction of coolant temperature and pressure. With a negative MTC, the cooldown results in a reduction of core shutdown margin. If the most reactive control rod is assumed to be stuck in its fully withdrawn position, there is a possibility that the core can become critical and return to power even with the remaining control rods inserted. A return to power following a steam pipe rupture is a potential problem only because of the high hot-channel factors that can exist when the most reactive rod is assumed stuck in its fully withdrawn position. Even if the most pessimistic combination of circumstances that could lead to power generation following a steamline break was assumed, the core is ultimately shut down by the boric acid in the SIS.

The analysis of a steam pipe rupture was made to show that assuming the most reactive RCCA stuck in its fully withdrawn position and assuming the worst single failure in the engineered safety features (ESFs), the core cooling capability could be maintained and that offsite doses would not exceed applicable limits. In addition, the analysis considers conditions both with and without offsite power available.

Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis showed that DNB did not occur, thus ensuring clad integrity.

The following systems provide the necessary protection against a steam pipe rupture:

- SIS actuation from any one of the following:
  - — Two-out-of-3 channels of low pressurizer pressure signals
  - — Two-out-of-3 high differential pressure signals between steamlines
  - — High steam flow in 2-out-of-4 lines (1-out-of-2 per line) in coincidence with either low RCS average temperature (2-out-of-4) or low steamline pressure (2-out-of-4)
  - — Two-out-of-3 high containment pressure signals
  - — High-high containment pressure (two sets of 2-out-of-3)
  - — Manual actuation
- The overpower reactor trips (nuclear flux and ΔT) and the reactor trip occurring upon actuation of the SIS.
- Redundant isolation of the main feedwater lines. Sustained high feedwater flow would cause additional cooldown. However, in addition to the normal control action that will close the main feedwater valves, any safety injection signal will rapidly close all feedwater control valves (including the motor-operated block valves and low-flow bypass valves) and close the feedwater pump discharge valves, which in turn would trip the main feedwater pumps.
- Closing the fast-acting steamline stop valves (designed to close in less than 5 seconds) on:
  - — High steam flow in 2-out-of-4 lines (1-out-of-2 per line) in coincidence with either low RCS average temperature (2-out-of-4) or low steamline pressure (2-out-of-4)
  - — High-high containment pressure (two sets of 2-out-of-3).

Each main steamline has a fast-closing stop valve and a check valve. These eight valves prevent blowdown of more than one steam generator for any MSLB location even if one valve fails to close. For example, for a MSLB upstream of the stop valve in one line, a closure of either the check valve in that line or the stop valves in the other lines will prevent blowdown of the other steam generators.

For breaks downstream of the isolation valves, closure of all valves will completely terminate the blowdown. For any main steamline break, in any location, no more than one steam generator would experience an uncontrolled blowdown even if one of the isolation valves fails to close.

The effective throat area of the steam generator flow restrictor nozzles is bounded by 1.4 ft^2. These flow areas are considerably less than the main steam pipe area. Thus, the flow restrictor nozzles serve to limit the maximum steam flow for a break at any location.

6.3.11.2 Input Parameters and Assumptions

The following conditions are assumed to exist at the time of a MSLB accident.

EOL shutdown margin at no-load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position are all assumed. Operation of the control rod banks during core burnup is restricted in such a way that addition of positive reactivity in a steamline break accident will not lead to a more adverse condition than the case analyzed.

The negative moderator coefficient corresponds to an EOL rodded core with the most-reactive RCCA withdrawn. The variation of the coefficient with temperature and pressure is included. The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector are conservatively combined to obtain average core properties for reactivity feedback calculations. Furthermore, it is conservatively assumed that the core power distribution was uniform. These two conditions cause an underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity and power distribution is checked for the limiting statepoints for the cases analyzed.

This core analysis considers the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution, and non-uniform core inlet temperature effects. For cases in which steam generation occurred in the high flux regions of the core, the effect of void formation is also included. It was determined that the reactivity used in the kinetics analysis was always larger than the reactivity calculated, including the above local effects for the statepoints. These results verified conservatism, that is, an underprediction of negative reactivity feedback from power generation.

Minimum capability for injection of high-concentration boric acid (2400 ppm) solution corresponding to the most restrictive single failure in the High-Head Safety Injection System (HHSIS) is assumed. The Emergency Core Cooling System (ECCS) consists of three systems:

the passive accumulators, the Residual Heat Removal System (RHRS), and the HHSIS. Only the accumulators and HHSIS are modeled for the steamline break accident analysis.

The actual modeling of the accumulators and HHSIS in RETRAN is described in WCAP-14882-P-A (Reference 1). A conservative flow is modeled in the analysis for the HHSIS that reflects a composite modeling of the minimum SI flow resulting from either a failure of one train of the HHSIS or a failure of a cold-leg branch line motor-operated valve (MOV). No credit is taken for the low-concentration borated water, which must be swept from the lines downstream of the RWST prior to the delivery of concentrated boric acid to the RCLs.

For the case in which offsite power is assumed, the sequence of events in the HHSIS is the following. After the generation of the SI signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves began to operate and the HHSI pumps started. In 12 seconds, the valves are assumed to be in the final position and the pump is assumed to be at full speed. In cases where offsite power is not available, an additional 10-second delay is assumed to start the diesels and load the necessary SI equipment onto them.

Design value of the steam generator heat transfer coefficient including allowance for fouling factor is assumed.

Since the steam generators have integral flow restrictors bounded by a 1.4 ft^2 throat area, any rupture with a break area greater than the area of the flow restrictor, regardless of the location, would have the same effect on the NSSS as the break equal to the area of the flow restrictor. The following cases were considered in determining the core power and RCS transients.

Case 1: Complete severance of a pipe, with the plant initially at no-load conditions, and full reactor coolant flow with offsite power available.

Case 2: Case 1 with LOOP coincident with the steamline break. LOOP results in RCP coastdown, which was assumed to begin at 3 seconds.

Power peaking factors corresponding to one stuck RCCA and non-uniform core inlet coolant temperatures are determined at EOL. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return-to-power phase following the steamline break. This void, in conjunction with the large negative moderator coefficient, partially offsets the effect of the stuck assembly. The power peaking factors depend on the core conditions for power, temperature, pressure, and flow, and thus are different for each case studied.

The core conditions used for both with and without offsite power cases correspond to values determined from the respective transient analyses.

Both cases assumed hot shutdown conditions at event initiation since this represents the most conservative initial condition. These hot shutdown initial conditions are considered for cases assuming full-power operation at HFP high T_{avg} of 572°F. Should the reactor be just critical or operating at power at the time of a steamline break, the reactor would be tripped by the normal Overpower Protection System when the power level reaches a trip setpoint. Following a trip at power, the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steamline break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy is removed, the cooldown and reactivity insertions proceeded in the same manner as in the analysis, which assumes no-load conditions at time zero. In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steamline breaks occurring at power.

Perfect moisture separation in the steam generator is assumed.

6.3.11.3 Description of Analysis

The double-ended rupture of a major steamline is the most-limiting cooldown transient. It was analyzed at zero power with no decay heat since decay heat would retard the cooldown, thereby reducing the return to power.

The analysis of the steam pipe break was performed to determine:

- The core heat flux and RCS temperature and pressure resulting from the cooldown following the steamline break. The RETRAN code (Reference 1) was used to calculate the transient conditions.
- The thermal-hydraulic behavior of the core following a steamline break. A detailed thermal-hydraulic digital computer code, VIPRE, was used to determine if DNBR fell below the safety analysis limit for the core conditions computed in the above bulleted paragraph.

6.3.11.4 Acceptance Criteria

A main steamline break is classified as an ANS Condition IV event, a limiting fault. Condition IV occurrences are faults that are not expected to take place, but are postulated because their consequences would include the potential for the release of significant amounts of radioactive material. Condition IV faults are not to cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values presented in 10CFR100. However, the main steamline break transient is conservatively analyzed to the applicable Condition II criteria, demonstrating that the DNB design basis is satisfied. Therefore, the analysis presented in this section conservatively meets the radiological dose criteria set forth for a steamline break. Also, the effects of minor steamline breaks, which are classified as Condition II events, are bounded by the analysis presented in this section.

6.3.11.5 Results

The calculated sequences of events for both cases are shown in Table 6.3-10.

The results presented were a conservative indication of the events that would occur assuming a steamline break, since it is postulated that all of the conditions described above occur simultaneously.

Conservatively assuming a stuck RCCA with or without offsite power, and assuming a single failure in the ESFs, the core remained in place and intact. Although DNB and possible clad perforation are not necessarily unacceptable following a steam pipe break, the analysis in fact shows that the DNBR never falls below the safety analysis limit for any break assuming the most reactive assembly stuck in its fully withdrawn position, as demonstrated in Table 6.3-18. By meeting the DNB design basis criterion, this analysis also conservatively meets the radiological dose criteria set forth for a steamline break.

Core Power and RCS Transient

Figure 6.3-63 shows the core heat flux and core reactivity following a MSLB (complete severance of a steam pipe) at initial no-load conditions. Figure 6.3-64 shows the corresponding vessel inlet temperature and pressurizer pressure after the break occurs. Figure 6.3-65 shows steam flow and steam generator mass of the faulted and intact steam generators during the event. Offsite power was assumed available so that full reactor coolant flow existed. The transient shown assumed an uncontrolled steam release from only one steam generator. Should the core be critical at near-zero power when the break occurs, the initiation of SI by low-pressurizer pressure or high steam flow coincident with either low RCS average temperature or low steamline pressure will trip the reactor. Steam release from more than one steam generator

will be prevented by automatic closure of the fast-acting isolation valves in the steamlines by high steam flow coincident with either low RCS average temperature or low steamline pressure. Even with the failure of one valve, release is limited to no more than approximately 27 seconds for the other steam generators while the one generator blows down. The steamline stop valves are designed to be fully closed in less than 5 seconds from receipt of a closure signal.

The core attained criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) before boron solution at 2400 ppm entered the RCS. A peak core power lower than the nominal full-power value was attained.

The calculation assumed the boric acid was mixed with, and diluted by, the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depended upon the relative flow rates in the RCS and in the HHSIS. The variation of mass flow rate in the RCS due to water density changes was included in the calculation as is the variation of flow rate in the HHSIS due to changes in the RCS pressure. The HHSIS flow calculation included the line losses in the system as well as the pump head curve. Figure 6.3-66 illustrates the core averaged boron concentration during the event.

For the case assuming coincidental LOOP when the SI signal is generated, the SIS delay time included 10 seconds to start the diesel, in addition to the 12 seconds to start the SI pump and open the valves. Criticality was achieved later, and the core power increase was slower, than in the case with offsite power available. The ability of the emptying steam generator to extract heat from the RCS was reduced by the decreased flow in the RCS. The peak power remained well below the nominal full-power value.

It should be noted that following a main steamline break, only one steam generator blows down completely. Thus, the remaining steam generators were still available for dissipation of decay heat after the initial transient was over. In the case with LOOP, this heat was removed to the atmosphere via the steamline safety valves.

Margin to Critical Heat Flux

DNB analyses were performed for the most conservative of the two analyzed cases, that is, the case with offsite power. The minimum DNBR was greater than the safety analysis limit value.

6.3.11.6 Conclusions

The analysis showed that the acceptance criteria stated earlier in subsection 6.3.11.4 were satisfied. Although DNB and possible cladding perforation following a steam pipe break were not necessarily unacceptable and not precluded by the criteria, the above analysis showed that the DNBR never fell below the safety analysis limit.

6.3.12 Partial Loss-of-Reactor-Coolant Flow

6.3.12.1 Introduction

A partial loss-of-forced-reactor-coolant-flow accident can result from a mechanical or electrical failure in an RCP, or from a fault in the power supply to these pumps. If the reactor is at power at the time of the event, the immediate effect is a rapid increase in coolant temperature. This increase in coolant temperature could result in DNB, with subsequent fuel damage, if the reactor is not promptly tripped.

The reactor trip on low reactor coolant flow provides protection against partial loss-of-flow conditions. This function is generated by 2-out-of-3 low-flow signals per RCL. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10 percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip.

6.3.12.2 Input Parameters and Assumptions

This accident is analyzed using the RTDP (Reference 3). Initial core power (consistent with SPU conditions) and reactor coolant pressure are assumed to be at their nominal values for steady-state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). MMF is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used along with the most positive MTC limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

Normal reactor control systems and engineered safety systems (for example, SI) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.3.12.3 Description of Analysis

A partial loss-of-flow involving the loss of one RCP with four loops in operation was analyzed for the SPU conditions.

The transient was analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot channel heat flux transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient presented was based on the minimum of the typical and thimble cells.

6.3.12.4 Acceptance Criteria

A partial loss-of-forced-reactor-coolant-flow incident is classified by the ANS as a Condition II event. The immediate effect is a rapid increase in reactor coolant temperature and subsequent increase in RCS pressure. The primary acceptance criterion for this event is that the critical heat flux should not be exceeded. This was ensured by demonstrating that the minimum DNBR did not go below the applicable safety analysis limit at any time during the transient. The analysis results also demonstrated that pressure in the RCS and MSS remained below 110 percent of the respective design pressures to ensure that the applicable Condition II pressure criteria were met.

6.3.12.5 Results

The partial loss-of-forced-reactor-coolant-flow event was the least DNB-limiting transient among all loss-of-flow cases. Reactor trip for the partial loss-of-flow case occurred on a low primary coolant flow signal. The VIPRE analysis confirmed that the minimum DNBR was greater than the safety analysis limit. Fuel clad damage criteria were not challenged in the partial loss-of-forced-reactor-coolant-flow event since the DNB criterion was met, as demonstrated in Table 6.3-18.

The analysis of the partial loss-of-flow event also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The sequence of events for the partial loss-of-flow transient is presented in Table 6.3-11. The transient results for this case are presented in Figures 6.3-67 through 6.3-69.

6.3.12.6 Conclusions

The analysis performed at SPU conditions demonstrated that, for the partial loss-of-flow incident, the DNBR did not decrease below the safety analysis limit at any time during the transient; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remained below their respective limits at all times. All applicable acceptance criteria were therefore met.

6.3.13 Complete Loss-of-Reactor-Coolant Flow

6.3.13.1 Introduction

A complete loss-of-forced-reactor-coolant-flow accident can result from simultaneous loss of electrical power or a reduction in supply frequency to all RCPs. If the reactor is at power at the time of the event, the immediate effect is a rapid increase in coolant temperature. This increase in coolant temperature could result in DNB, with subsequent fuel damage, if the reactor is not promptly tripped.

The following signals provide protection against a complete loss-of-forced-reactor-coolant-flow incident:

- Low voltage or low frequency on pump power supply bus (above Permissive P-7).
- Low reactor coolant flow (1-out-of-4 above Permissive P-8, 2-out-of-4 above Permissive P-7).
- RCP circuit breakers opening (1-out-of-4 above Permissive P-8, 2-out-of-4 above Permissive P-7).

The reactor trip on RCP undervoltage protects against conditions that can cause a loss of voltage to all RCPs, that is, LOOP. The reactor trip on RCP underfrequency is provided to protect against frequency disturbances on the power grid.

The reactor trip on low primary coolant loop flow provides protection against loss-of-flow conditions that affect individual RCLs and serves as a backup for the undervoltage and underfrequency trip functions. The reactor trip on low primary coolant loop flow is generated by 2-out-of-3 low-flow signals per RCL. Above Permissive P-8, low flow in any loop will actuate a reactor trip. Between approximately 10-percent power (Permissive P-7) and the power level corresponding to Permissive P-8, low flow in any two loops will actuate a reactor trip.

6.3.13.2 Input Parameters and Assumptions

This accident is analyzed using the RTDP (Reference 3). Initial core power (consistent with uprated power conditions) and reactor coolant pressure are assumed to be at their nominal values for steady-state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). MMF is also assumed. A conservatively large absolute value of the Doppler-only power coefficient is used along with the most positive (MTC) limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR was reached.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

Normal RCS and engineered safety systems (for example, SI) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.3.13.3 Description of Analysis

The following complete loss-of-forced-reactor-coolant-flow cases were analyzed for the SPU.

- Complete loss-of-flow transient due to a complete loss of power to all RCPs with four loops in operation
- Complete loss-of-flow transient due to an underfrequency condition

Case 1 assumed that the RCPs begin to coast down upon reaching an undervoltage trip setpoint (modeled to occur at t = 0 seconds in this analysis). Rod motion following the undervoltage trip was modeled to occur at t = 1.5 seconds, reflecting an undervoltage trip time delay of 1.5 seconds. For the underfrequency event (Case 2), a frequency decay rate of 5 Hz/sec was assumed to begin at t = 0 seconds, decreasing pump speed, and thus, flow to all loops. At t = 1.0 seconds, the underfrequency trip setpoint of 55.0 Hz was reached. Rod motion occurred at t=1.6 seconds, following a 0.6-second underfrequency trip time delay.

The transients were analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot-channel-heat-flux-transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient was based on the minimum of the typical and thimble cells.

6.3.13.4 Acceptance Criteria

A complete-loss-of-forced-reactor-coolant-flow incident is classified by the ANS as a Condition III event. However, since a Condition II LOOP event could lead to a Condition III complete-loss-of-flow-event, the incident is analyzed to meet the more restrictive Condition II criteria to bound the complete loss-of-flow following a LOOP event.

The immediate effect from a complete-loss-of-forced-reactor-coolant flow is a rapid increase in reactor coolant temperature and subsequent increase in RCS pressure. The primary acceptance criterion for this event is that the critical heat flux should not be exceeded. This was ensured by demonstrating that the minimum DNBR did not go below the applicable safety analysis limit at any time during the transient.

The analysis results also demonstrated that pressure in the RCS and MSS remained below 110 percent of the respective design pressures to ensure that the applicable Condition II pressure criteria were met.

6.3.13.5 Results

For the IP3 SPU, both the undervoltage and frequency decay transients were analyzed. The VIPRE analyses for these scenarios confirmed that the minimum DNBR values were greater than the safety analysis limit, as demonstrated in Table 6.3-18.

The analysis of the complete-loss-of-flow event also demonstrated that the peak RCS and MSS pressures were well below their respective limits.

The sequence of events for the more limiting complete-loss-of-flow case, the frequency decay transient, is presented in Table 6.3-12. The transient results for this case are presented in Figures 6.3-70 through 6.3-72.

6.3.13.6 Conclusions

The analysis of the undervoltage and frequency decay cases, performed at SPU conditions, demonstrated that the DNBR did not decrease below the safety analysis limit at any time during the transients, thus, the integrity of the fuel was maintained. The peak primary and secondary system pressures remained below their respective limits at all times. Therefore, all applicable acceptance criteria were met.

6.3.14 Locked Rotor Accident

6.3.14.1 Introduction

The event postulated is an instantaneous seizure of a RCP rotor or the sudden break of a RCP shaft. Flow through the affected RCL is rapidly reduced, leading to initiation of a reactor trip on a low-RCL flow signal.

Following initiation of the reactor trip, heat stored in the fuel rods continues to be transferred to the coolant causing the coolant to expand. At the same time, heat transfer to the shell-side of the steam generators is reduced; first because the reduced primary flow results in a decreased tube-side film coefficient, and secondly because the reactor coolant in the tubes cools down while the shell-side temperature increases (turbine steam flow is reduced to zero upon plant trip due to turbine trip on reactor trip). The rapid expansion of coolant in the reactor core, combined with reduced heat transfer in the steam generators, causes an insurge into the pressurizer and a pressure increase throughout the RCS. The insurge into the pressurizer compresses the steam volume, actuates the automatic spray system, opens the PORVs, and opens the PSVs, in that sequence. The two PORVs are designed for reliable operation and would be expected to function properly during the event. However, for conservatism, their pressure-reducing effect, as well as the pressure-reducing effect of the pressurizer spray, was not included in the analysis.

The consequences of a locked rotor (that is, an instantaneous seizure of a pump shaft) are very similar to those of a pump shaft break. The initial rate of reduction in coolant flow is slightly greater for the locked rotor event. However, with a broken shaft, the impeller could conceivably be free to spin in the reverse direction. The effect of reverse spinning is to decrease the steady-state core flow when compared to the locked rotor scenario. The analysis considered the most-limiting combination of conditions for the locked rotor and pump-shaft break events.

6.3.14.2 Input Parameters and Assumptions

Two cases are evaluated in the analysis. Both assumed one locked RCP rotor/shaft break with a total of four loops in operation.

The first case is analyzed to evaluate the RCS pressure and fuel clad temperature transient conditions. This case is analyzed using the STDP. Initial core power, reactor coolant temperature, and pressure are assumed to be at their maximum values consistent with the uprated full-power conditions including allowances for calibration and instrument errors. This assumption results in a conservative calculation of fuel clad temperature transient conditions and of the coolant insurge into the pressurizer, which in turn results in a maximum calculated peak RCS pressure. In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

The second case is an evaluation of DNB in the core during the transient. This case is analyzed using the RTDP (Reference 3). Initial core power (consistent with SPU conditions) and reactor coolant pressure are assumed to be at their nominal values for steady state, full-power operation. Reactor coolant temperature is assumed to be at the nominal value for the high T_{avg} program. Uncertainties in initial conditions are included in the DNBR limit as described in the RTDP (Reference 3). A conservatively large absolute value of the Doppler-only power coefficient is used along with the most-positive MTC limit for full-power operation (0 pcm/°F). These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached. In addition, a 0.85-percent core flow penalty is modeled to account for RCS loop-to-loop flow asymmetry.

A conservatively low trip reactivity value (4.0-percent $\Delta\rho$) is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth RCCA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position is modeled in addition to a conservative rod drop time (2.7 seconds to dashpot). The trip reactivity versus rod position curve is confirmed to be valid as part of the RSAC verification process.

Normal reactor control systems and engineered safety systems (for example, SI) are not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

6.3.14.3 Description of Analysis

The transients were analyzed using two computer codes. First, the RETRAN computer code (Reference 1) was used to calculate the loop and core flow transients, nuclear power transient, and primary system pressure and temperature transients. The VIPRE computer code (Reference 8) was then used to calculate the hot channel heat flux transient and DNBR, based on the nuclear power and RCS flow from RETRAN. The DNBR transient is based on the minimum DNBR of the typical and thimble cells.

For the peak RCS pressure evaluation, the initial pressure was conservatively estimated as 60 psi above the nominal pressure of 2250 psia to allow for errors in pressurizer pressure measurement and control channels. This provides the highest possible rise in the coolant pressure during the transient. The pressure response reported in Table 6.3-13 was for the point in the RCS having the maximum pressure.

For a conservative analysis of fuel rod behavior, the hot spot evaluation assumed that DNB occurred at initiation of the transient and continues throughout the event. This assumption reduces heat transfer to the coolant and results in conservatively high hot spot temperatures.

Evaluation of the Pressure Transient

After pump seizure, coolant flow in the loop with the faulted RCP decreased rapidly and RCS temperature and pressure increased. A reactor trip signal was generated when the flow in the affected loop reached 87 percent of nominal flow. Rod motion began 1 second later and the neutron flux was rapidly reduced by control rod insertion. As RCS pressure increased, no credit was taken for the pressure-reducing effect of pressurizer PORVs or pressurizer spray, nor was credit taken for steam dump or controlled feedwater flow after plant trip. Although these systems are expected to function and would result in a lower peak pressure, an additional degree of conservatism was provided by not including their effect.

Evaluation of DNB in the Core during the Event

For this event, DNB was assumed to occur in the core; therefore, an evaluation of the consequences with respect to fuel rod thermal transients was performed. Results obtained from analysis of this hot spot condition represent the upper limit with respect to clad temperature and zirconium-water reaction. In the evaluation, the rod power at the hot spot conservatively considers an F_Q of 2.50. The number of rods-in-DNB is conservatively calculated for use in dose consequence evaluations.

6.3.14.4 Acceptance Criteria

The RCP locked rotor accident is classified by the ANS as a Condition IV event. The following items summarize the criteria associated with this event:

- Fuel cladding damage, including melting, due to increased reactor coolant temperatures must be prevented. This is precluded by demonstrating that the maximum clad temperature at the core hot spot remains below 2700°F, and the zirconium-water reaction at the core hot spot is less than 16 weight percent.

- Pressure in the RCS should be maintained below that which would cause stresses to exceed the faulted condition stress limits.

- Rods-in-DNB should be less than or equal to that assumed in the radiological dose analyses for the locked rotor/shaft break event.

6.3.14.5 Results

The results of the locked rotor/shaft break analysis are summarized in Table 6.3-13 and demonstrate that the acceptance criteria documented in subsection 6.3.14.4 continue to be met for the SPU. The number of rods-in-DNB (calculated as 0-percent rods-in-DNB) was less than that supported by the radiological dose analysis. Hence, the rods-in-DNB criterion was also met for the locked rotor/shaft break event. The calculated sequence of events is presented in Table 6.3-14 for the locked rotor event. The transient results for the peak-pressure/hot-spot case are provided in Figures 6.3-73 through 6.3-75.

6.3.14.6 Conclusions

The analysis performed at SPU conditions demonstrated that, for the locked rotor/shaft break event, the peak clad temperature calculated for the hot spot during the worst transient remained considerably less than 2700°F and the amount of zirconium-water reaction was small. Under such conditions, the core will remain in place and intact with no loss-of-core-cooling capability.

The analysis also confirmed that the peak RCS pressure reached during the transient was less than that which would cause stresses to exceed the faulted condition stress limits. The rods-in-DNB design criterion was also met.

The protection features previously described in subsection 6.3.14.1 provided mitigation for a locked rotor/shaft break transient such that the above criteria were satisfied.

6.3.15 Rupture of a CRDM Housing – RCCA Ejection

6.3.15.1 Introduction

This accident is defined as a mechanical failure of a CRDM pressure housing resulting in the ejection of the RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. The resultant core thermal power excursion is limited by the Doppler reactivity effect of the increased fuel temperature, and terminated by reactor trip actuated by high nuclear power signals.

A failure of a CRDM housing sufficient to allow a control rod to be rapidly ejected from the core is not considered credible for the following reasons.

- Each full-length mechanism housing is completely assembled and shop-tested at 4100 psig.
- The mechanism housings are individually hydrotested after they are attached to the head adapters in the reactor vessel head and checked during the hydrotest of the completed RCS.
- Stress levels in the mechanism are not affected by anticipated system transients at power or by thermal movement of the coolant loops. Moments induced by the design earthquake can be accepted within the allowable primary working stress ranges specified in the ASME Code, Section III, for Class I components.
- The latch mechanism housing and rod travel housing are each a single length of forged type-304 stainless steel. This material exhibits excellent notch toughness at all temperatures that will be encountered.

A significant margin of strength in the elastic range, together with the large energy absorption capability in the plastic range, gives additional assurance that gross failure of the housing will not occur. The joints between the latch mechanism housing and rod travel housing are threaded joints reinforced by canopy-type rod welds.

In general, the reactor is operated with the RCCAs inserted only far enough to control design neutron flux shape. Reactivity changes caused by core depletion are compensated for by boron changes. Furthermore, the location and grouping of control rod banks are selected during the nuclear design to lessen the severity of a RCCA ejection accident. Therefore, should a RCCA be ejected from its normal position during full-power operation, only a minor reactivity excursion,

at worst, could be expected to occur. The position of all RCCAs is continuously indicated in the control room. An alarm will occur if a bank of RCCAs approaches its insertion limit or if one control rod assembly deviates from its bank. There are low and low-low level insertion alarm circuits for each bank. The control rod position monitoring and alarm systems are described in WCAP-7588 (Reference 10).

6.3.15.2 Input Parameters and Assumptions

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The most important parameters are discussed below. Table 6.3-15 lists the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either 3-D static methods or a synthesis of 1-D and 2-D calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux-flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. The analysis assumes adverse xenon distributions to provide worst-case results.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties.

Delayed Neutron Fraction, β

The ejected rod accident is sensitive to β if the ejected rod worth is equal to or greater than β, as in the zero-power transients. To allow for future fuel cycle flexibility, conservative estimates of β of 0.50 percent at beginning of cycle and 0.40 percent at end of cycle are used in the analysis.

Reactivity Weighting Factor

The largest temperature rises, and hence the largest reactivity feedbacks, occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple single-channel analysis. Physics calculations have been performed for temperature changes with a flat temperature distribution and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which, when applied to single-channel feedbacks, account for the effective whole-core feedbacks for the appropriate flux shape.

In this analysis, a 1-D (axial) spatial kinetics method is employed; thus axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature, as a function of time, accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative when compared to 3-D analysis (Reference 10).

Moderator and Doppler Coefficient

The critical boron concentrations at the BOL and EOL are adjusted in the nuclear code to obtain moderator density coefficient curves that are conservative when compared to the actual design conditions for the plant. As discussed above, no weighting factor is applied to these results.

The Doppler reactivity defect is determined as a function of power level using a 1-D steady-state computer code with a Doppler weighting factor of 1.0. The Doppler weighting factor will increase under accident conditions, as discussed above.

Heat Transfer Data

The FACTRAN (Reference 5) code, used to determine the hot spot transient, contains standard curves of thermal conductivity versus fuel temperature. During a transient, the peak centerline fuel temperature is independent of gap conductance during the transient. The cladding temperature is, however, strongly dependent on gap conductance and is highest for high-gap conductance. For conservatism, a high-gap heat transfer coefficient of 10,000 Btu/hr-ft^2-°F has been used during transients. This value corresponds to a negligible gap resistance and a further increase would have essentially no effect on the rate of heat transfer.

Coolant Mass Flow Rates

When the core is operating at full power, all four coolant pumps will always be operating. For zero-power conditions, the system is conservatively assumed to be operating with two pumps. The principal effect of operating at reduced flow is to reduce the film-boiling heat transfer coefficient. This results in higher peak cladding temperatures, but does not affect peak centerline fuel temperature. Reduced flow also lowers the critical heat flux. However, since DNB is always assumed at the hot spot and the heat flux rises very rapidly during the transient, this produces only second-order changes in the cladding and centerline fuel temperatures. All zero-power analyses for both average core and the hot spot are conducted assuming two pumps in operation.

Trip Reactivity Insertion

The trip reactivity insertion is assumed to be 4 percent ΔK/K from HFP and 2 percent ΔK/K from HZP, including the effect of one stuck RCCA. These values are also reduced by the ejected rod. The shutdown reactivity is simulated by dropping a rod of the required worth into the core. The start of rod motion occurs 0.55 seconds after reaching the power-range high-neutron-flux trip setpoint. It is assumed that insertion to dashpot occurs 2.7 seconds after the rods begin to fall. The time delay to full insertion, combined with the 0.55 second trip delay, conservatively delays insertion of shutdown reactivity into the core.

The minimum design shutdown margin available for this plant at HZP may only occur at EOL in the equilibrium cycle. This value includes an allowance for the worst stuck rod, an adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations have shown that two stuck RCCAs (one of which is the worst ejected rod) reduce the shutdown margin by about an additional 1 percent ΔK/K. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

6.3.15.3 Description of Analysis

This section describes the models used in the analysis of the rod ejection accident. Only the initial few seconds of the power transient are discussed, since the long-term considerations are the same as for a LOCA.

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then a hot region (hot spot) calculation. The average core calculation uses spatial neutron-kinetics methods to determine average power generation versus time including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. Enthalpy and temperature transients at the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and by performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is conservatively assumed to exist throughout the transient. A detailed discussion of the method of analysis can be found in WCAP-7588, Revision 1-A (Reference 10).

Average Core Analysis

The spatial-kinetics computer code, TWINKLE (Reference 4) is used for the average core transient analysis. This code solves the two-group neutron diffusion theory kinetic equation in one, two, or three spatial dimensions (rectangular coordinates) for 6 delayed neutron groups and up to 8000 spatial points. The computer code includes a detailed multi-region, transient

fuel-clad-coolant-heat-transfer model for calculation of point-wise Doppler and moderator feedback effects. This analysis uses the code as a 1-D axial kinetics code since it allows a more-realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to use very conservative methods (described below) for calculating the ejected rod worth and hot channel factor.

Hot Spot Analysis

In the hot spot analysis, the initial heat flux is equal to the nominal heat flux times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot conditions before and after ejection are coincident. This is very conservative since the peak nuclear power after ejection will occur in or adjacent to the assembly with the ejected rod, whereas prior to ejection the power in this region will be depressed.

The average core energy addition, calculated as described above, is multiplied by the appropriate hot channel factors. The hot spot analysis uses the detailed fuel and clad transient heat transfer computer code, FACTRAN (Reference 5). This computer code calculates the transient temperature distribution in a cross section of a metal-clad UO_2 fuel rod and the heat flux at the surface of the rod, using as input the nuclear power versus time and local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative pellet radial power distribution is assumed within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 11) to determine the film-boiling coefficient after DNB. The use of the Bishop-Sandberg-Tong correlation conservatively assumes zero bulk fluid quality. The DNB heat flux is not calculated; instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted to force the full-power, steady-state temperature distribution to agree with fuel heat transfer design codes.

Reactor Protection

The protection for this accident, as explicitly modeled in the analysis, is provided by the power-range high-neutron-flux trip (high and low settings). This protection function is part of the Reactor Trip System. No single failure of the Reactor Trip System will negate the protection function required for the rod ejection accident, or adversely affect the consequences of the accident.

6.3.15.4 Acceptance Criteria

Due to the extremely low probability of an RCCA ejection accident, this event is classified as an ANS Condition IV event. As such, some fuel damage could be considered an acceptable consequence.

The Idaho Nuclear Corporation (Reference 12) has carried out comprehensive studies of the threshold of fuel failure and the threshold of significant conversion of the fuel thermal energy to mechanical energy as part of the SPERT project. Extensive tests of UO_2 zirconium-clad fuel rods representative of those present in PWR-type cores have demonstrated failure thresholds in the range of 240 to 257 cal/gm. However, other rods of a slightly different design exhibited failure as low as 225 cal/gm. These results differ significantly from the TREAT (Reference 13) results, which indicated a failure threshold of 280 cal/gm. Limited results have indicated that this threshold decreased 10 percent with fuel burnup. The clad failure mechanism appears to be melting for unirradiated (zero burnup) rods and brittle fracture for irradiated rods. The conversion ratio of thermal to mechanical energy is also important. This ratio becomes marginally detectable above 300 cal/gm for unirradiated rods, and 200 cal/gm for irradiated rods; catastrophic failure (large fuel dispersal, large pressure rise), even for irradiated rods, did not occur below 300 cal/gm.

The real physical limits of this accident are that the rod ejection event and any consequential damage to either the core or the RCS must not prevent long-term core cooling and any offsite dose consequences must be within the guidelines of 10CFR100. More specific and restrictive criteria are applied to ensure fuel dispersal in the coolant, gross lattice distortion or severe shock waves will not occur. In view of the above experimental results, and the conclusions of WCAP-7588, Revision 1-A (Reference 10) and Westinghouse letter NS-NRC-89-3466 (Reference 14), the limiting criteria are:

- Average fuel pellet enthalpy at the hot spot must be maintained below 200 cal/gm.

- Peak reactor coolant pressure must be less than that which could cause RCS stresses to exceed the faulted-condition stress limits.

- Fuel melting is limited to less than 10 percent of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of the criterion in the first bulleted paragraph.

6.3.15.5 Results

A summary of the parameters used in the rod ejection analyses, and the analysis results, are listed in Table 6.3-15. For both HFP cases, control bank D is assumed at its insertion limit. For both HZP cases, control bank D is assumed fully inserted with banks B and C at their insertion limits.

The nuclear power and hot spot fuel and clad temperature transients for all 4 cases, BOL HFP, BOL HZP, EOL HFP, and EOL HZP are shown in Figures 6.3-76 through 6.3-83. The sequence of events for all 4 cases are listed in Tables 6.3-16 and 6.3-17.

For all four cases, the peak hot spot average enthalpy is less than the acceptance criteria limit of 200 cal/gm (360 Btu/lb) (maximum). The peak fuel centerline temperature for the HFP cases exceeded the conservative assumed temperature for fuel melt (4900°F at BOL; 4800°F at EOL), but the predicted fuel melt is less than the acceptance criterion limit of 10-percent fuel pellet volume (maximum) at the hot spot. The peak fuel centerline temperature for the HZP cases remained below the conservative assumed temperature for fuel melt (4900°F at BOL; 4800°F at EOL) and resulted in no fuel pellet melt at the hot spot.

A detailed calculation of the pressure surge for an ejected rod worth of 1 dollar at BOL HFP, indicates that the peak pressure does not exceed that which would cause RPV stress to exceed the faulted condition stress limits (Reference 10). Since the severity of the RCCA ejection analysis presented in this section does not exceed the severity of the "worst-case" peak pressure analysis in Reference 10, the RCCA ejection accident will not result in an excessive pressure rise or further adverse effects to the RCS for this plant.

6.3.15.6 Conclusions

Despite the conservative assumptions, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10 percent of the fuel rods in the core.

6.3.16 References

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2. WCAP-9272-P-A (Proprietary), *Westinghouse Reload Safety Evaluation Methodology*, F. M. Bordelon et. al., July 1985.

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11. ASME 65-HT-31, *Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux*, A. A. Bishop, R. O. Sandberg, and L. S. Tong, August 1965.

12. *Annual Report - SPERT Project, October 1968 - September 1969*, IN-1370 Idaho Nuclear Corporation, T. G. Taxebius, ed., June 1970.

13. ANL-7225, P 177, *Studies in TREAT of Zircaloy 2-Clad, UO_2-Core Simulated Fuel Elements*, R. C. Liimatainen and F. J. Testa, November 1966.

14. Letter NS-NRC-89-3466, *Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents*, from W. J. Johnson of Westinghouse Electric Corporation to Mr. R. C. Jones of the NRC, October 23,1989.

Table 6.3-1

List of Non-LOCA Events

Licensing Report Section	Event	UFSAR Section	Non-LOCA Computer Code
6.3.2	Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition	14.1.1	TWINKLE FACTRAN VIPRE
6.3.3	Uncontrolled RCCA Withdrawal at Power	14.1.2	RETRAN
6.3.4	RCCA Drop/Misoperation	14.1.3 / 14.1.4	LOFTRAN ANC VIPRE
6.3.5	CVCS Malfunction	14.1.5	N/A
6.3.6	Loss-of-External-Electrical Load	14.1.8	RETRAN
6.3.7	LONF	14.1.9	RETRAN
6.3.8	LOAC to the Station Auxiliaries	14.1.12	RETRAN
6.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	14.1.10	RETRAN VIPRE
6.3.10	Excessive Load Increase Incident	14.1.11	N/A
6.3.11	Rupture of a Steam Pipe	14.2.5	RETRAN ANC VIPRE
6.3.12	Partial Loss-of-Reactor-Coolant Flow	14.1.6	RETRAN VIPRE
6.3.13	Complete Loss-of-Reactor-Coolant Flow	14.1.6	RETRAN
6.3.14	Locked Rotor Accident	14.1.6	RETRAN VIPRE
6.3.15	Rupture of a CRDM Housing – RCCA Ejection	14.2.6	TWINKLE FACTRAN

Note:
No evaluation was performed for UFSAR Section 14.1.7, "Startup of an Inactive Reactor Coolant Loop." Per the IP3 ITS, it is required that all 4 RCPs be operating for reactor power operation.

Table 6.3-2 Trip Setpoint and Maximum Time Delay for Non-LOCA Safety Analysis		
Reactor Trip Function	**Time Delay (seconds)**	**Maximum Trip Setpoint Assumed for Analysis**
Power Range Flux (high setting)	0.5	118%
Power Range Flux (low setting)	0.5	35%
OTΔT	2.0[1]	Variable (see Section 6.3.1)
OPΔT	2.0[1]	Variable (see Section 6.3.1)
High-Pressurizer Pressure	2.0	2470 psia
Low-Pressurizer Pressure	N/A[2]	1850 psia
Low Reactor Coolant Flow	1.0	87% of loop flow
Low-Low Steam Generator Water Level	2.0	0% NRS
Turbine Trip	4.0	N/A
Engineering Safety Feature Actuation System (ESFAS) Function		
High-High Steam Generator Water Level (feedwater isolation) (turbine trip)	 12.0 5.0	 85% NRS 85% NRS

Note:

1. Additional delays include RTD response time and filter time constant setting. The total delay is 10.5 seconds.
2. Reactor trip function not explicitly credited in non-LOCA safety analyses; however, a low-pressurizer pressure reactor trip safety analysis setpoint is assumed, as the OTΔT and OPΔT reactor trip functions are required to protect the core between the low- and high-pressurizer pressure reactor trips.

Table 6.3-3 Non-LOCA Key Accident Analysis Assumptions for IP3 SPU	
NSSS Power	3230 MWt (bounds 3182 MWt)
Reactor Power	3216 MWt (bounds 3168 MWt)
NSSS Thermal Design Flow (per loop)	88,600 gpm
Minimum Measured Flow (per loop)	91,175 gpm
Core Bypass Flow Fraction (non-statistical) (statistical)	7.5% 6.8%
Programmed Full-Power RCS Average Temperature	572.0°F maximum 549.0°F minimum
Steam Generator Design	Westinghouse Model 44F
Maximum SGTP Level	10% uniform
DNB Methodology (where applicable)	RTDP
Safety Analysis Limit DNBR (RTDP, WRB-1 correlation)	1.45 (typical & thimble cell)
Max $F_{\Delta H}$ (non-statistical) (statistical)	1.70 1.635
Max F_Q (Locked Rotor) (RCCA Ejection)	2.50 2.56
Rod Average Thermal Output	6.644 kW/ft
Initial Condition Uncertainties: Power RCS flow Temperature Pressure Steam generator water level Pressurizer water level	 ± 2% RTP ± 2.9% ± 7.5°F (bounds ±4.8°F, +2.7/-0.7°F bias) ± 60 psi (bounds ± 52 psi, -3 psi bias) ± 10% NRS (bounds + 5.0/-8.5% NRS) ± 8.5% span (bounds ± 3.5% span, +1.6% span bias)

Table 6.3-4 Sequence of Events-Uncontrolled Rod Withdrawal from Subcritical Event	
Event	**Time (sec)**
Start of Accident	0.0
Power Range High Neutron Flux Low Setpoint Reached	9.7
Peak Nuclear Power Occurs	9.9
Rods Begin to Fall into Core	10.2
Peak Heat Flux Occurs	11.8
Minimum DNBR Occurs	11.8
Peak Fuel Cladding Inner Temperature Occurs	12.3
Peak Fuel Average Temperature Occurs	12.5
Peak Fuel Centerline Temperature Occurs	13.2

Table 6.3-5

Sequence of Events-Uncontrolled RCCA Bank Withdrawal at Power Analysis

Case	Event	Time(s)
100% Power, Minimum Feedback, Rapid RCCA Withdrawal (66 pcm/sec)	Initiation of uncontrolled RCCA withdrawal	0.0
	Power range high neutron flux (high setpoint reached)	1.9
	Rods begin to fall	2.4
	Minimum DNBR occurs	3.4
100% Power Minimum Feedback, Slow RCCA Withdrawal (1 pcm/sec)	Initiation of uncontrolled RCCA withdrawal	0.0
	OTΔT setpoint reached	95.5
	Rods begin to fall	97.5
	Minimum DNBR occurs	98.0

Table 6.3-6

Sequence of Events – Loss-of-Load/Turbine-Trip Event

Case	Event	Time (sec)
Peak Pressure Case	Loss-of-electrical load/turbine trip	0.0
	High-pressurizer pressure reactor trip setpoint reached	7.9
	Rods begin to drop	9.9
	Peak RCS pressure occurs	10.1
	Peak MSS pressure occurs	19.1
Minimum DNBR Case	Loss of electrical load/turbine trip	0.0
	OTΔT reactor trip setpoint reached	14.7
	Rods begin to drop	16.7
	Minimum DNBR occurs	17.9
	Peak MSS pressure occurs	23.1

Table 6.3-7 Time Sequence of Events for Loss-of-Normal Feedwater Flow	
Event	**Time (seconds)**
Main Feedwater Flow Stops	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	52.5
Rods Begin to Drop	54.5
Automatic AFW Flow from 1 MDAFWP (total 343 gpm) Initiated (split evenly between two loops)	112.5
Operator Action to Establish AFW Flow (an additional 343 gpm) to Remaining Steam Generators	654.5
Peak Water Level in the Pressurizer Occurs	1195.0

Table 6.3-8 Time Sequence of Events for Loss-of-Non-Emergency AC Power	
Event	**Time (seconds)**
Main Feedwater Flow Stops	20.0
Low-Low Steam Generator Water Level Reactor Trip Setpoint Reached	59.0
Rods Begin to Drop	61.0
RCPs Begin to Coast Down	63.0
Automatic AFW Flow from 1 MDAFWP (total 343 gpm) Initiated (split evenly between two loops)	119.0
Operator Action to Establish AFW Flow (an additional 343 gpm) to Remaining Steam Generators	661.0
Peak Water Level in the Pressurizer Occurs	785.0

Table 6.3-9

Feedwater System Malfunction at Power – Sequence of Events

Event	Time (seconds)
One Main Feedwater Control Valve Begins to Open	0
Feedwater Control Valve Reaches Full-Open Position	15
High-High Steam Generator Water Level Trip Setpoint is Reached	85.08
Turbine Trip Initiated from High-High Steam Generator Level	89.98
Minimum DNBR Occurs	91.85
Rod Motion Begins/Reactor Trip occurs	93.99
Feedwater Isolation Valves Begin to Close	96.98

Table 6.3-10 Time Sequence of Events for the Rupture of a Main Steamline		
Event	Case with Offsite Power Time (sec)	Case without Offsite Power Time (sec)
Double-Ended Steamline Rupture in Loop 1 (1.4 ft^2)	0.00	0.00
High Steamline Flow Setpoint Reached (2/4 loops)	0.25	0.25
LOOP (RCPs begin coasting down)	--	3.00
High Steamline Flow Signal Generated (2/4 loops)	8.25	8.25
Low-Low T_{avg} Setpoint Reached in Loop 1	8.81	9.24
Low-Low T_{avg} Setpoint Reached in Loop 2	11.53	12.56
Low-Pressurizer Pressure SI Setpoint Reached	15.29	16.94
Low-Low T_{avg} Signal Generated in Loop 1	16.81	17.24
Safety Injection and FWI Actuation due to Low Pressurizer Pressure	17.29	18.94
Low-Low T_{avg} Signal Generated in Loop 2	19.53	20.56
SLI Actuation due to Coincidence of Low-low T_{avg} (2/4 loops) / High Steam Flow (2/4 loops) ESF	19.54	20.57
MSIV Closure Loops 1, 2, 3, and 4	26.44[1]	27.47[1]
MFIV Closure Loops 1, 2, 3, and 4	27.19[1]	28.84[1]
SI Flow Initiated	29.31	40.95
Peak Core Heat Flux Occurs	39.80	67.72

Note:

1. Plus an additional 0.1 second for valve closure time.

Table 6.3-11 Sequence of Events – Partial Loss-of-Forced Reactor-Coolant-Flow Event		
Case	**Event**	**Time (sec)**
Partial Loss-of-Forced-Reactor-Coolant Flow (4 loops initially operating, 1 loop coasting down)	Coastdown begins	0.0
	Low flow reactor trip	1.5
	Rods begin to drop	2.5
	Minimum DNBR occurs	3.4

Table 6.3-12 Sequence of Events – Complete Loss-of-Forced Reactor-Coolant-Flow Event		
Case	**Event**	**Time (sec)**
Complete Loss-of-Forced-Reactor-Coolant Flow (frequency decay)	Frequency decay begins	0.0
	Underfrequency trip setpoint reached	1.0
	Rods begin to drop	1.6
	Minimum DNBR occurs	3.7

Table 6.3-13 Summary of Results for the Locked Rotor/Shaft Break Transient		
Criteria	**Analysis Value**	**Limit**
Maximum Clad Temperature at Core Hot Spot, °F	1792	2700
Maximum Zr-H_2O Reaction at Core Hot Spot, wt. %	0.28	16
Maximum RCS Pressure, psia	2530	2750

Table 6.3-14 Sequence of Events – Locked Rotor/Shaft Break Transient	
Event	**Time (sec)**
Rotor on One Pump Locks/Shaft Breaks	0.0
Low-Flow Reactor Trip Setpoint Reached	0.1
Rods Begin to Drop	1.1
Maximum Clad Temperature Occurs	3.9
Maximum RCS Pressure Occurs	5.9

Table 6.3-15 Inputs and Results of the RCCA Ejection Accident Analysis				
	Beginning of Cycle HFP	Beginning of Cycle HZP	End of Cycle HFP	End of Cycle HZP
Power Level, %	102	0	102	0
Ejected Rod Worth, %ΔK	0.17	0.65	0.20	0.80
Delayed Neutron Fraction, %	0.50	0.50	0.40	0.40
Feedback Reactivity Weighting	1.46	2.16	1.50	2.95
Trip reactivity, %ΔK	4.0	2.0	4.0	2.0
F_q before Rod Ejection	2.56	--	2.56	--
Ejected rod F_q	6.8	12.0	7.1	20.0
Number of Operational Pumps	4	2	4	2
Max Fuel Pellet Average Temperature, °F	4117	2524	3989	3066
Max Fuel Centerline Temperature, °F	4974	2900	4876	3425
Max Clad Average Temperature, °F	2256	1892	2177	2320
Max Fuel Stored Energy, Btu/lb	325	182	313	229
Fuel Melt at the Hot Spot, %	7.78	0	7.52	0

Table 6.3-16

Sequence of Events – RCCA Ejection Accident

Case	Event	Time (sec)
BOL, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.05
	Peak nuclear power occurs	0.13
	Rods begin to fall	0.60
	Peak fuel average temperature occurs	2.36
	PCT occurs	2.46
EOL, Full Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.04
	Peak nuclear power occurs	0.13
	Rods begin to fall	0.59
	Peak fuel average temperature occurs	2.48
	PCT occurs	2.56

Table 6.3-17 Sequence of Events – RCCA Ejection Accident		
Case	**Event**	**Time (sec)**
BOL, Zero Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.34
	Peak nuclear power occurs	0.40
	Rods begin to fall	0.89
	PCT occurs	2.52
	Peak fuel average temperature occurs	2.65
EOL, Zero Power	Initiation of rod ejection	0.0
	Power range high neutron flux setpoint reached	0.18
	Peak nuclear power occurs	0.21
	Rods begin to fall	0.73
	PCT occurs	1.56
	Peak fuel average temperature occurs	1.78

Table 6.3-18

Non-LOCA Analysis Limits and Results

Licensing Report Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
6.3.2	Uncontrolled RCCA Withdrawal from a Subcritical or Low-Power Startup Condition	Minimum DNBR below first mixing vane grid (non-RTDP, W-3 correlation) (thimble/typical)	1.45/1.45	1.72/1.93
		Minimum DNBR above first mixing vane grid (non-RTDP, WRB-1 correlation) (thimble/typical)	1.30/1.30	2.04/2.08
		Maximum fuel centerline temperature, °F	4800	2346
6.3.3	Uncontrolled RCCA Withdrawal at Power	Minimum DNBR (RTDP, WRB-1)	1.45	1.53
		Peak RCS pressure, psia	2750.0	2748.45
		Peak main steam system pressure, psia	1208.5	1179.24
6.3.4	RCCA Drop/Misoperation	Minimum DNBR (RTDP, WRB-1)	1.45	> 1.45
		Peak linear heat generation (kW/ft)	22.7	< 22.7
		Peak uniform cladding strain (%)	1.0	< 1.0
6.3.5	CVCS Malfunction	Minimum time to loss of shutdown margin, minutes		
	- Mode 1 with manual rod control		15	> 34 (Mode 1 with manual)
	- Mode 1 with automatic rod control		15	> 36 (Mode 1 with auto)
	- Mode 2		15	> 26 (Mode 2)
	- Mode 6		30	> 34 (Mode 6)

Table 6.3-18 (Cont.) Non-LOCA Analysis Limits and Results				
Licensing Report Section	Event Description	Result Parameter	Analysis Result	
			Analysis Limit	Limiting Case
6.3.6	Loss-of-External-Electrical Load	Minimum DNBR (RTDP, WRB-1)	1.45	1.85
		Peak RCS pressure, psia	2750.0	2700.50
		Peak main steam system pressure, psia	1208.5	1182.87
6.3.7	LONF	Maximum pressurizer mixture volume, ft3	1800.0	1596.1
6.3.8	LOAC to the Station Auxiliaries	Maximum pressurizer mixture volume, ft3	1800.0	1443.3
6.3.9	Excessive Heat Removal Due to Feedwater System Malfunctions	Minimum DNBR (RTDP, WRB-1)	1.45	2.21(HFP) (1)(HZP)
6.3.10	Excessive Load Increase Incident	Minimum DNBR (RTDP, WRB-1)	1.45	> 1.45
6.3.11	Rupture of a Steam Pipe	Minimum DNBR (non-RTDP, W-3)	1.45	2.37
6.3.12	Partial Loss-of-Reactor-Coolant Flow	Minimum DNBR (RTDP, WRB-1)	1.45	2.222
6.3.13	Complete Loss-of-Reactor-Coolant Flow			
	- Undervoltage	Minimum DNBR (RTDP, WRB-1)	1.45	1.956 (under-voltage)
	- Frequency Decay		1.45	1.865 (frequency decay)
6.3.14	Locked Rotor Accident	See Table 6.3-13		
6.3.15	Rupture of a CRDM Housing – RCCA Ejection	Maximum fuel pellet average enthalpy, Btu/lb	360	See Table 6.3-15
		Maximum fuel melt, %	10	See Table 6.3-15
		Peak RCS pressure, psia	Generically addressed in Section 6.3 Reference 10	

Note:

1. Bounded by zero power steam line break.

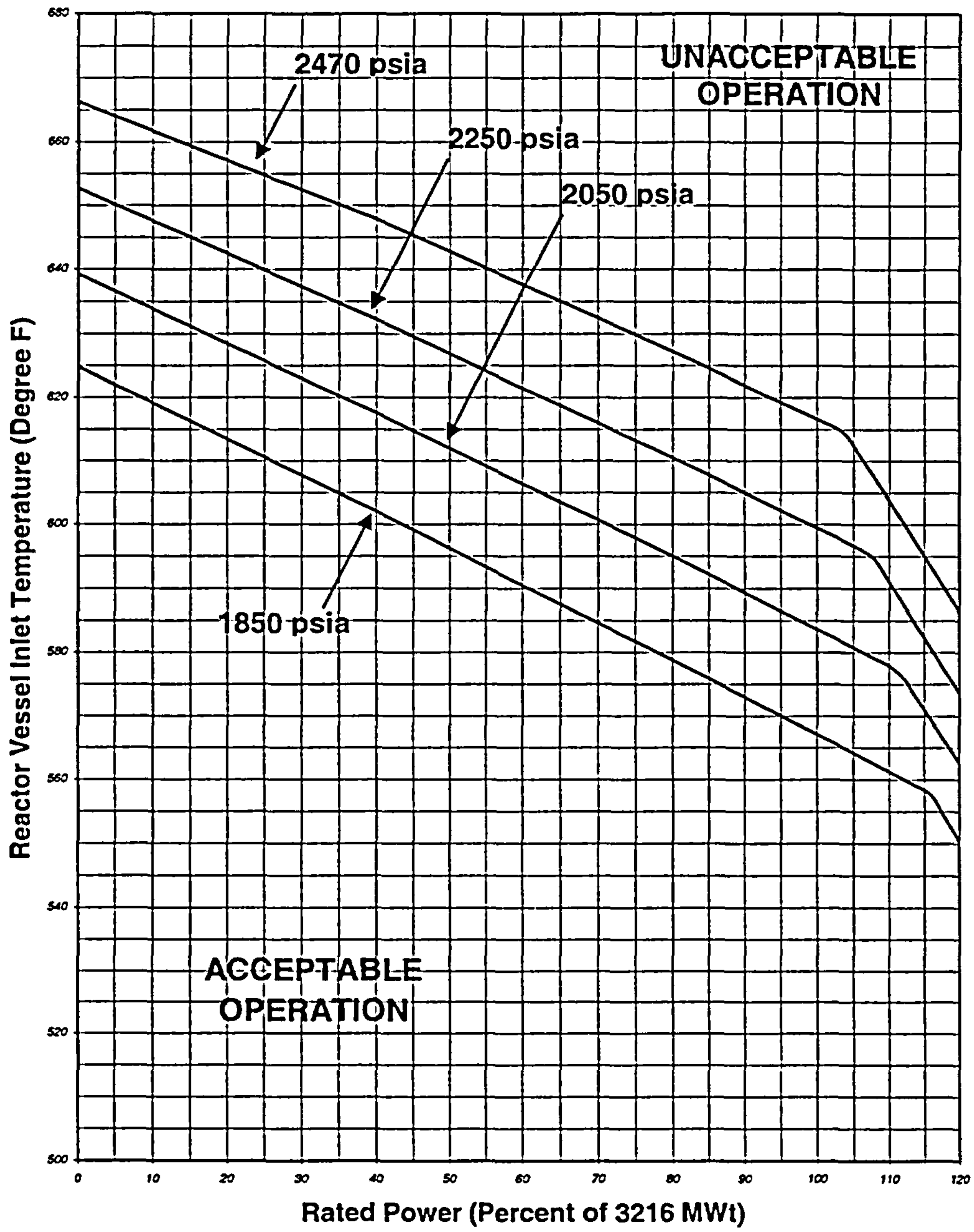


Figure 6.3-1

Reactor Core Safety Limit – Four Loops in Operation

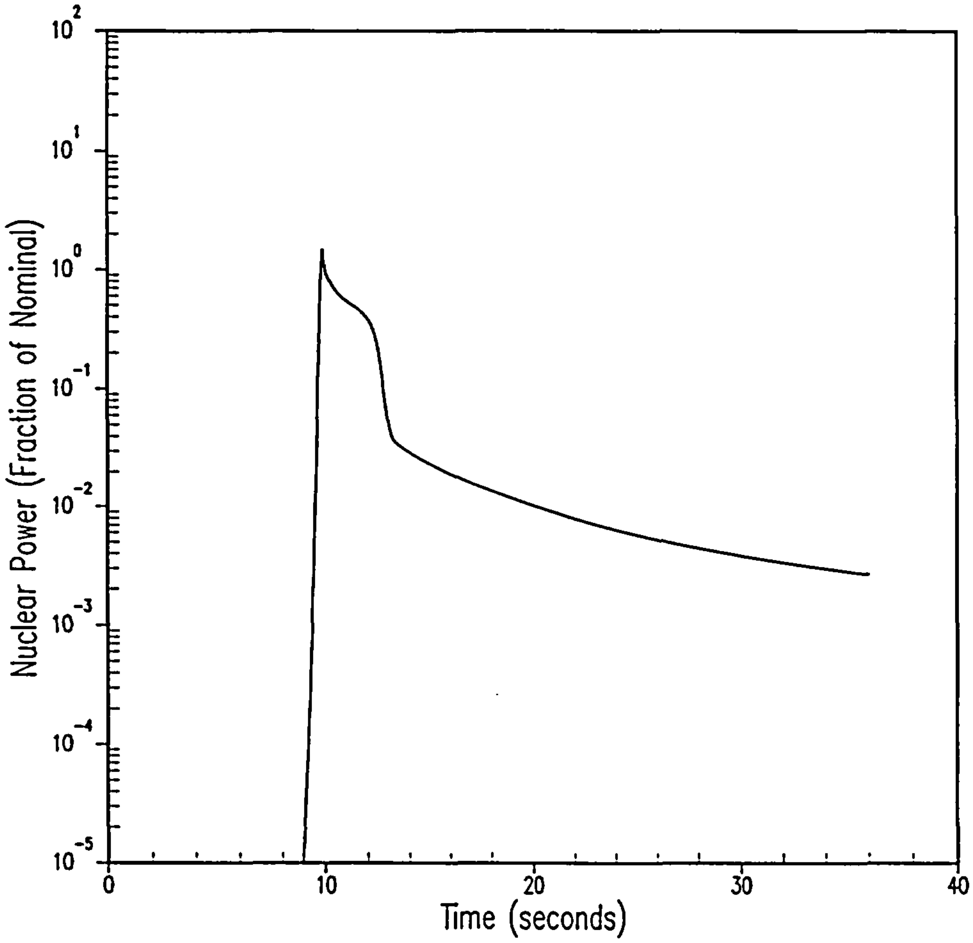


Figure 6.3-2

Nuclear Power Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition

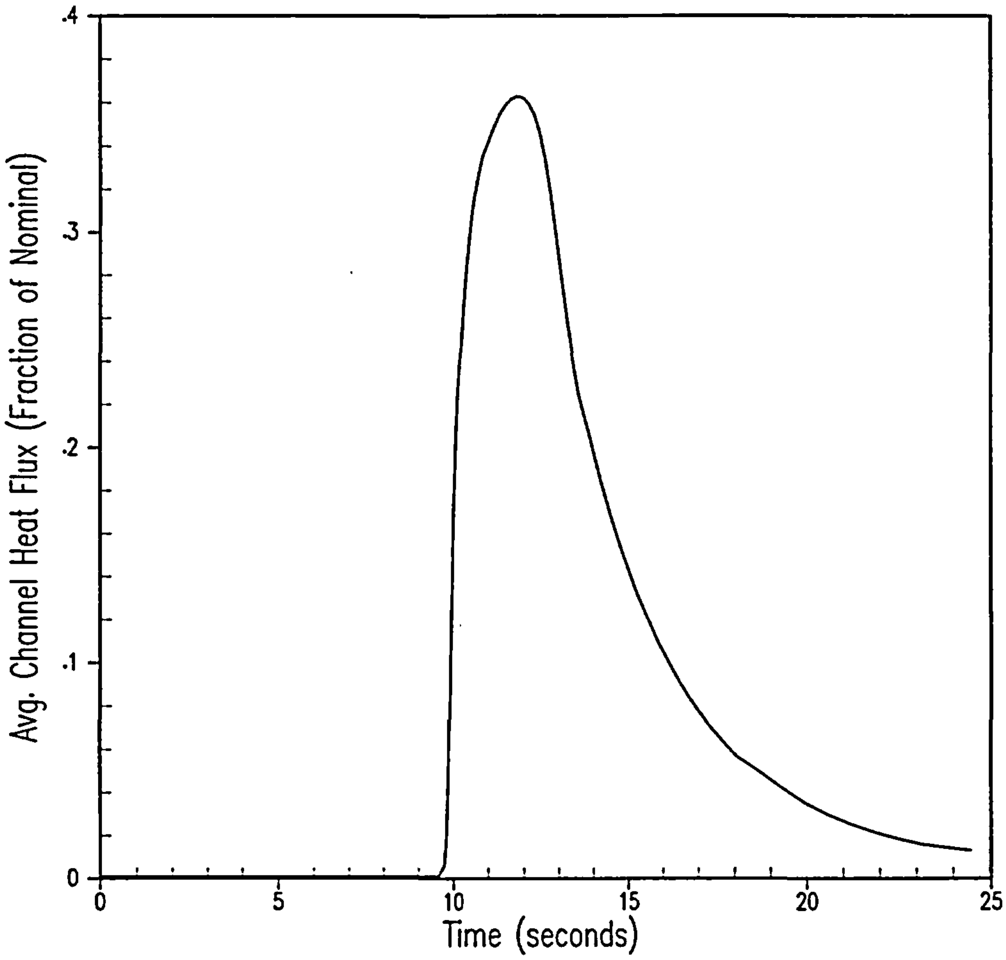


Figure 6.3-3

Thermal Flux Transient for Uncontrolled Rod Withdrawal from a Subcritical Condition

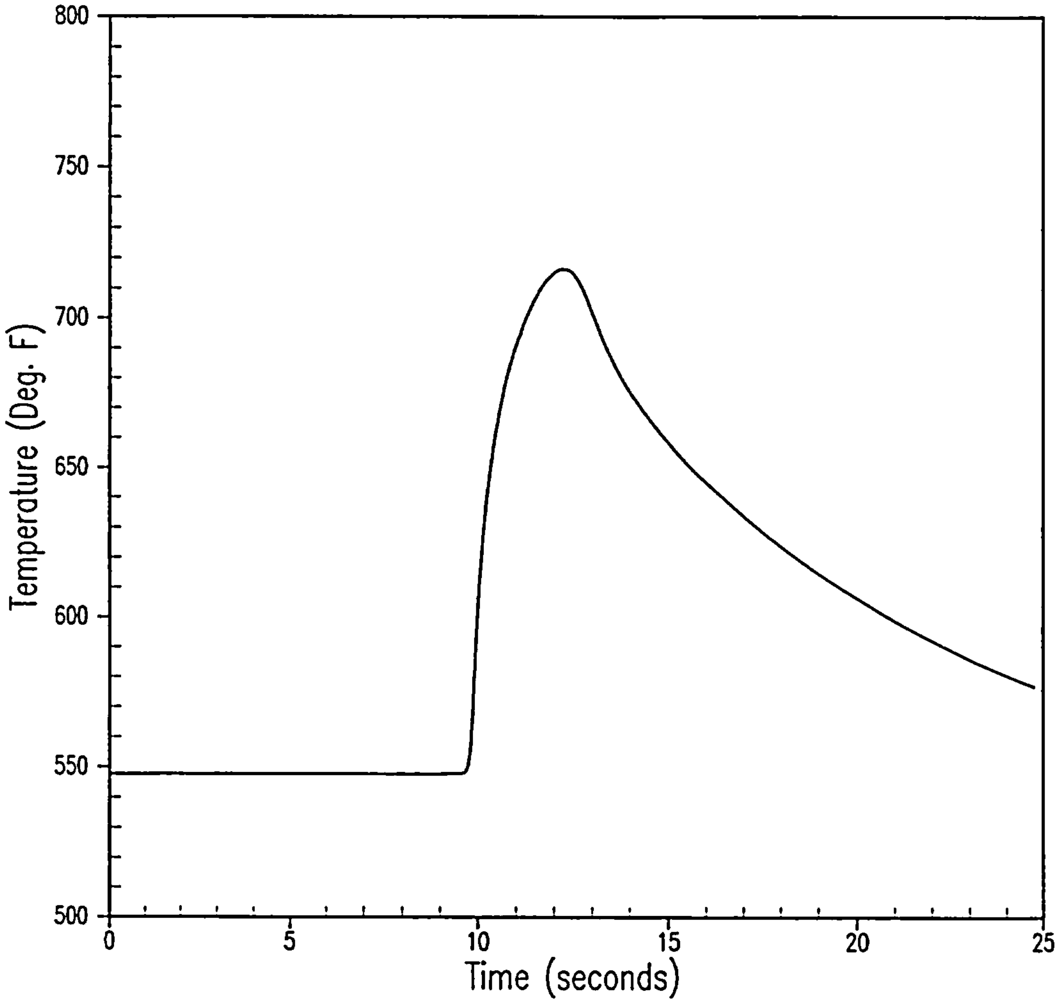


Figure 6.3-4

Hot Spot Clad Inner Temperature Transient for

Uncontrolled Rod Withdrawal from a Subcritical Condition

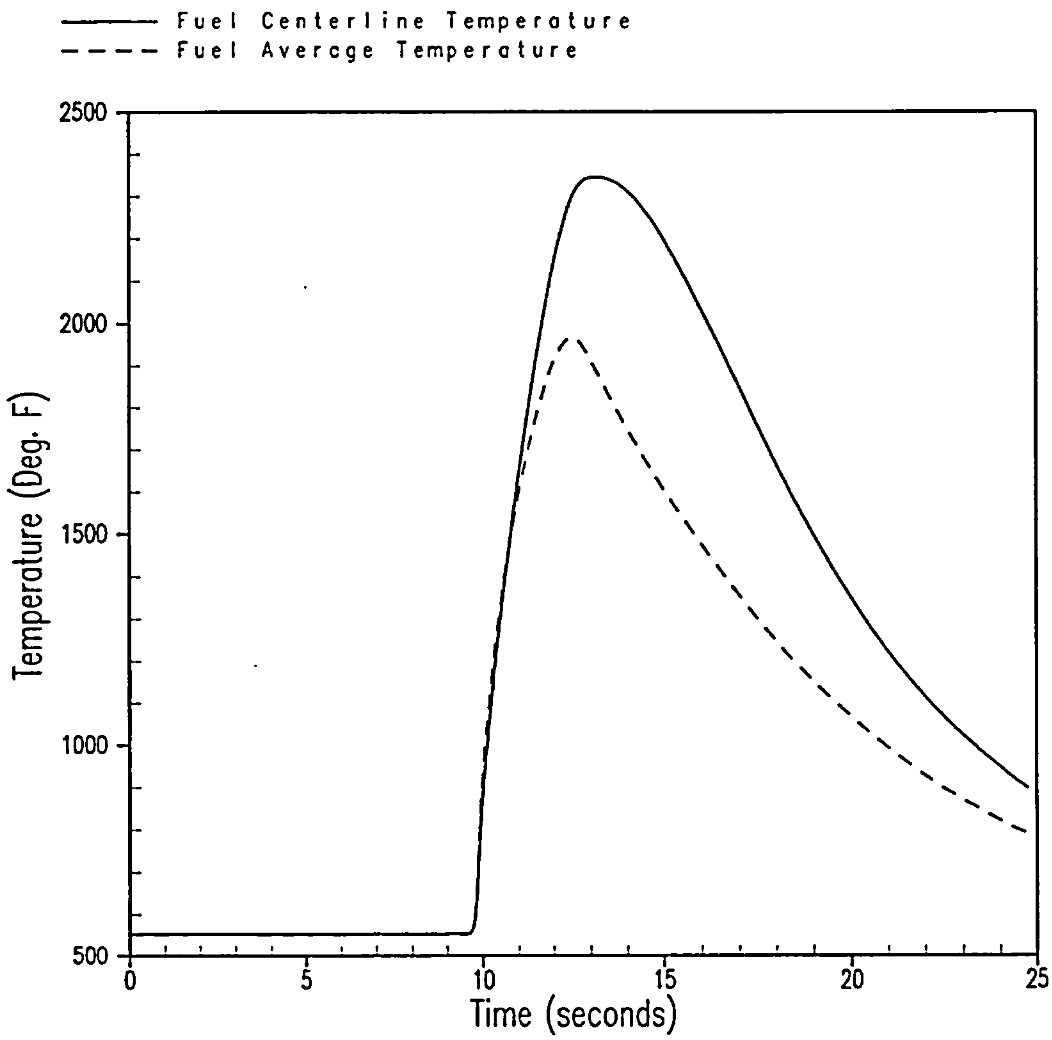


Figure 6.3-5

Hot Spot Fuel Centerline and Average Temperature Transients for Uncontrolled Rod Withdrawal from a Subcritical Condition

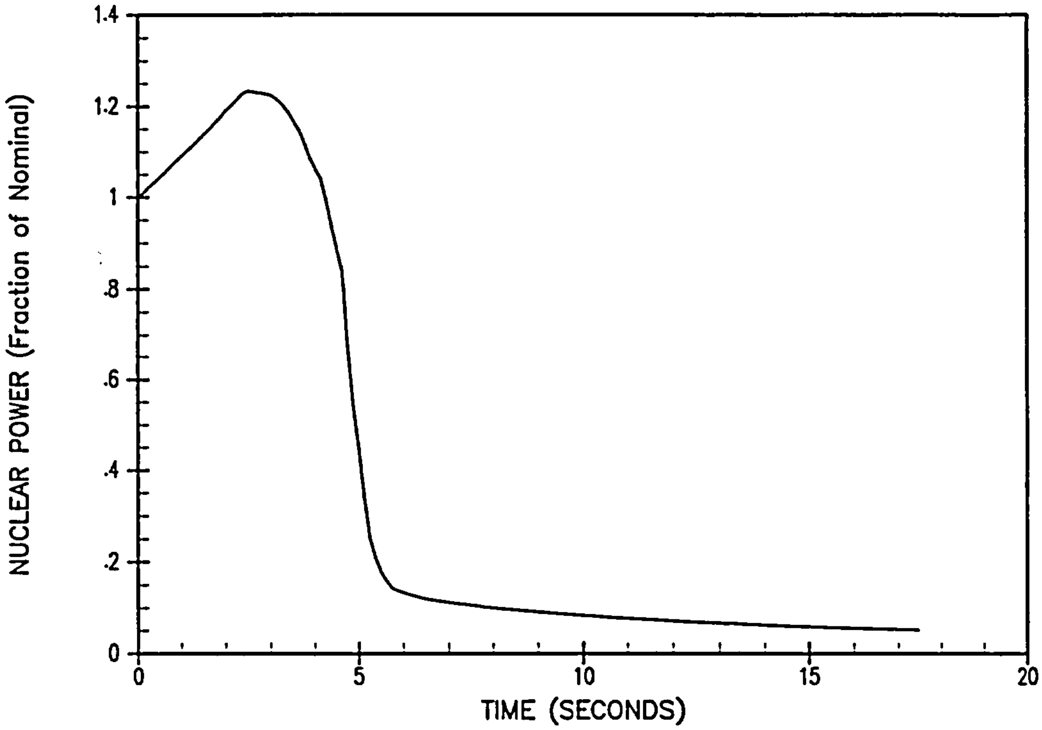


Figure 6.3-6

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Nuclear Power vs. Time)

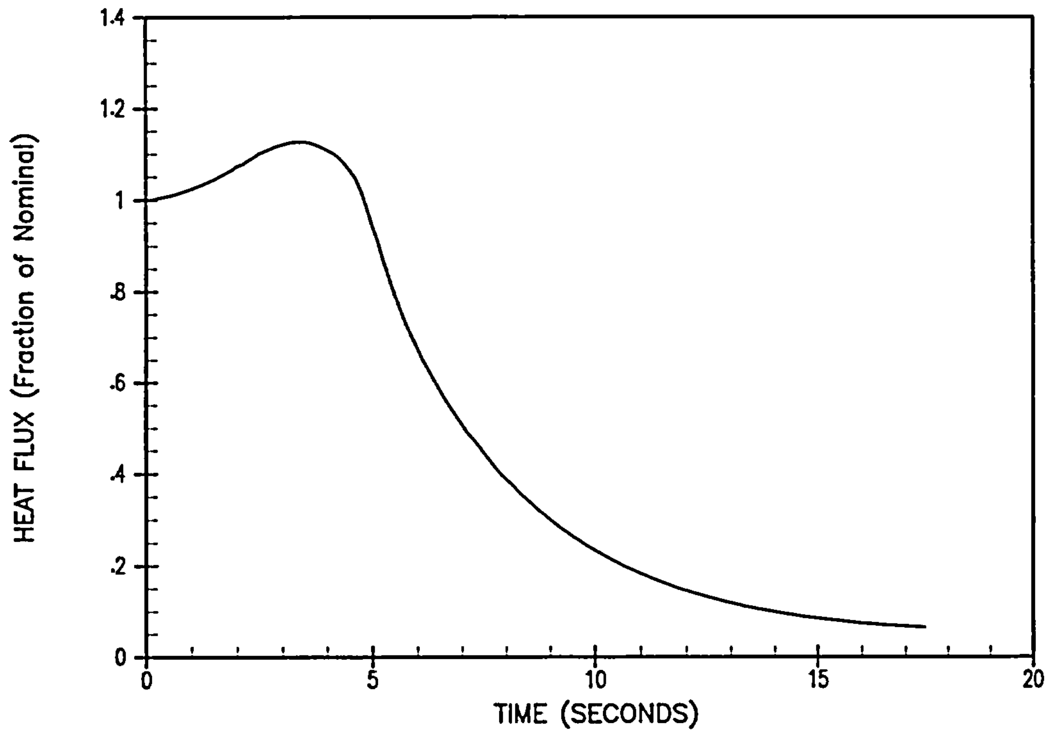


Figure 6.3-7

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Core Heat Flux vs. Time)

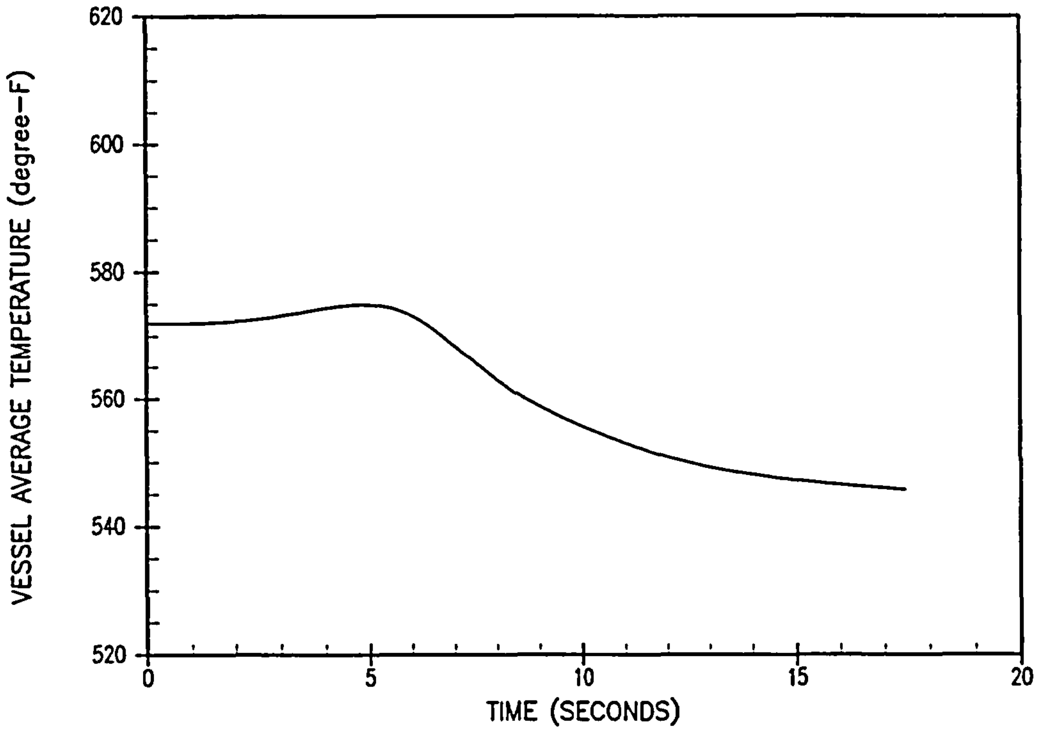


Figure 6.3-8

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Vessel Average Temperature vs. Time)

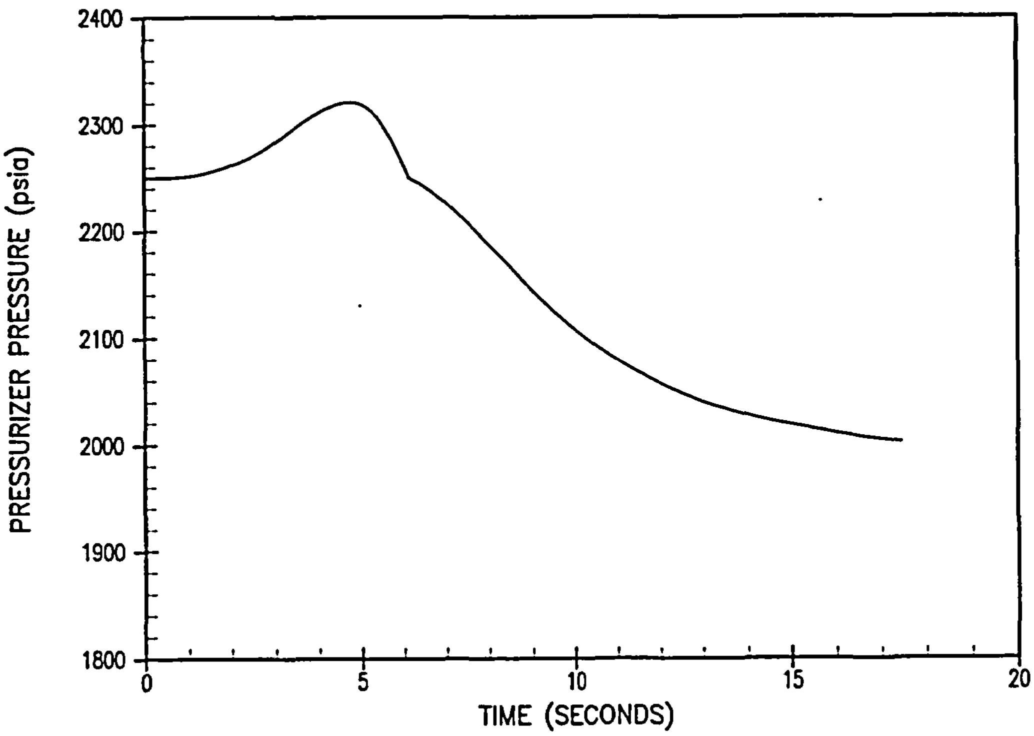


Figure 6.3-9

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second 100% Power - Minimum Reactivity Feedback (Pressurizer Pressure vs. Time)

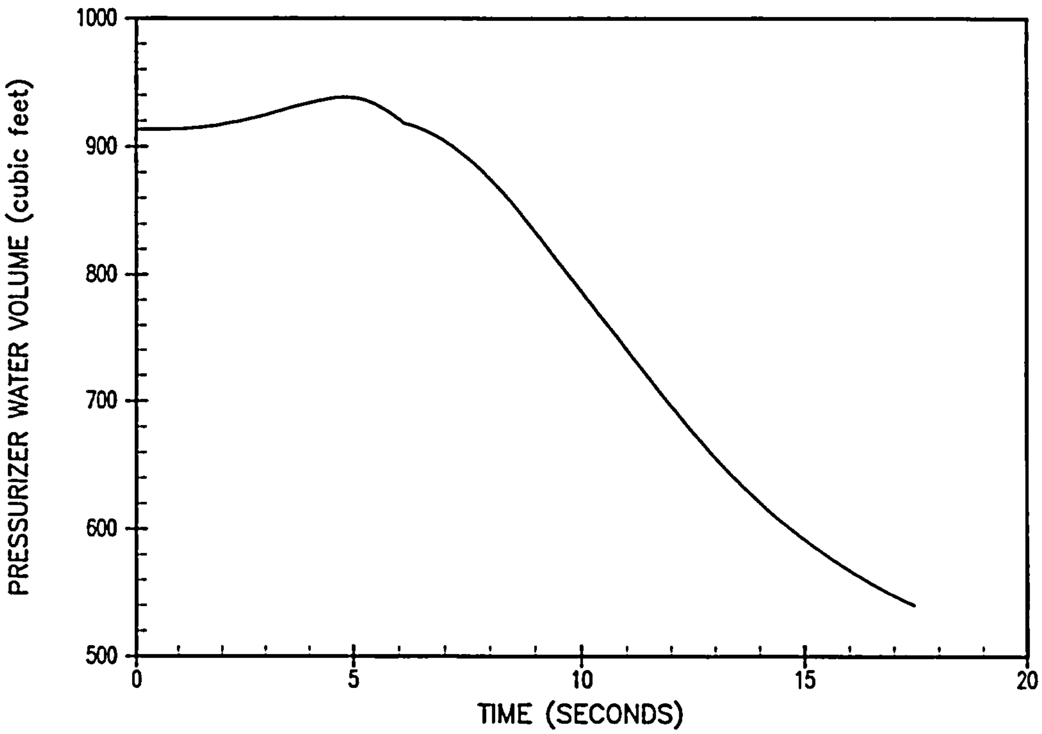


Figure 6.3-10

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Water Volume vs. Time)

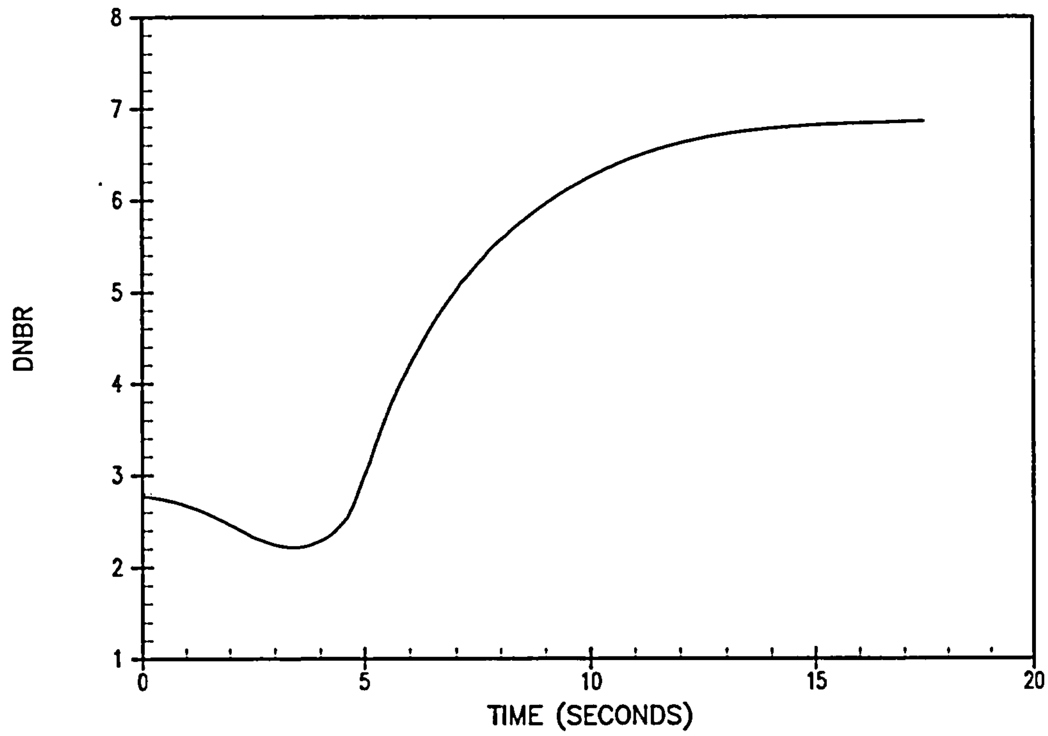


Figure 6.3-11

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 66 pcm/second

100% Power - Minimum Reactivity Feedback (DNBR vs. Time)

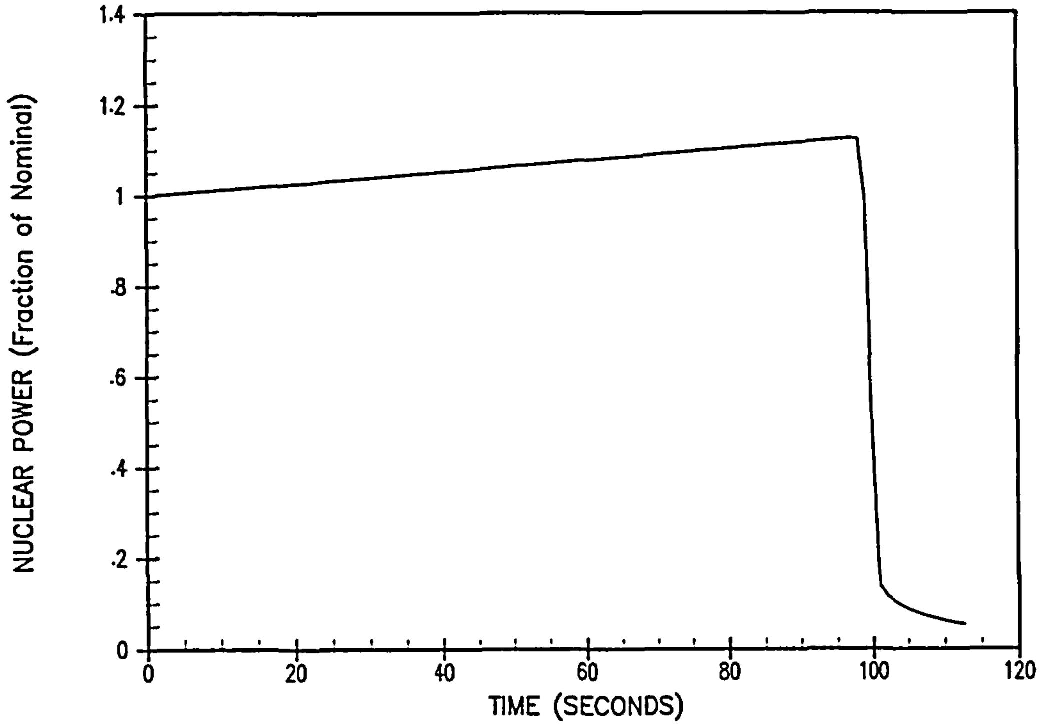


Figure 6.3-12

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second 100% Power - Minimum Reactivity Feedback (Nuclear Power vs. Time)

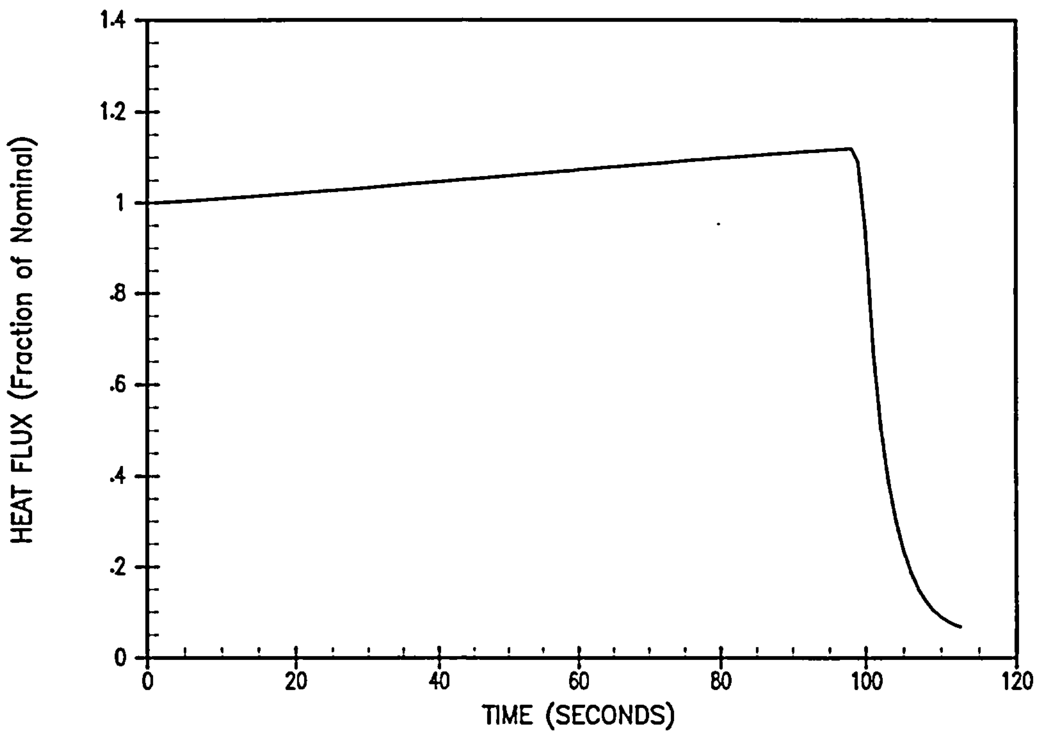


Figure 6.3-13

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Core Heat Flux vs. Time)

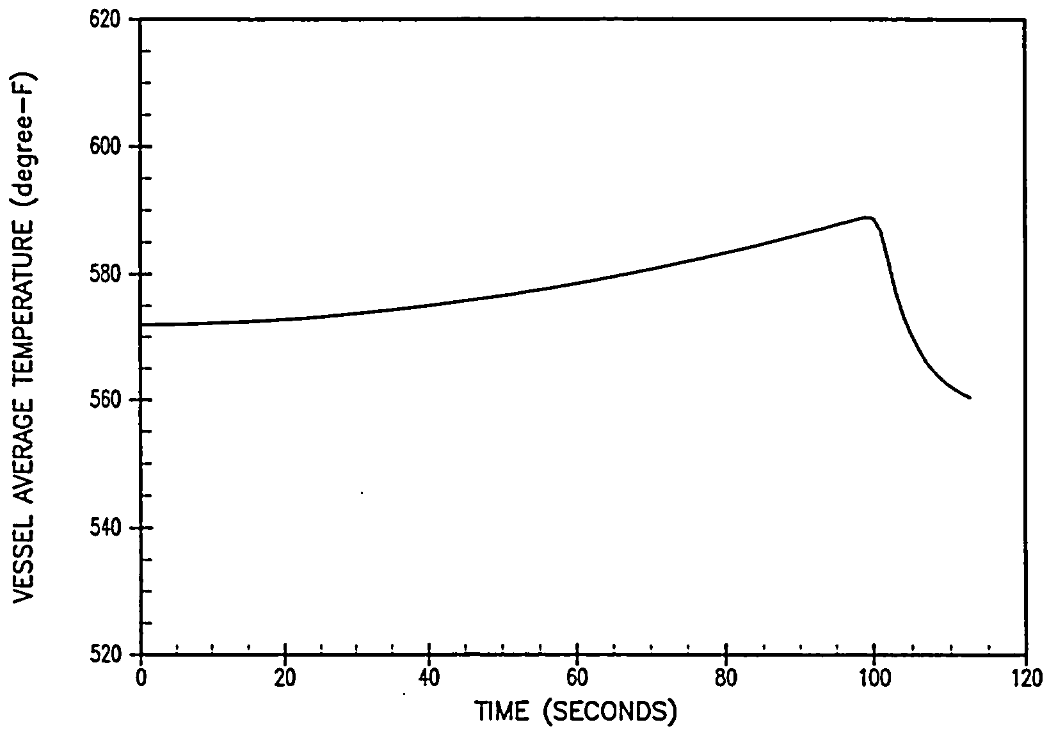


Figure 6.3-14

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Vessel Average Temperature vs. Time)

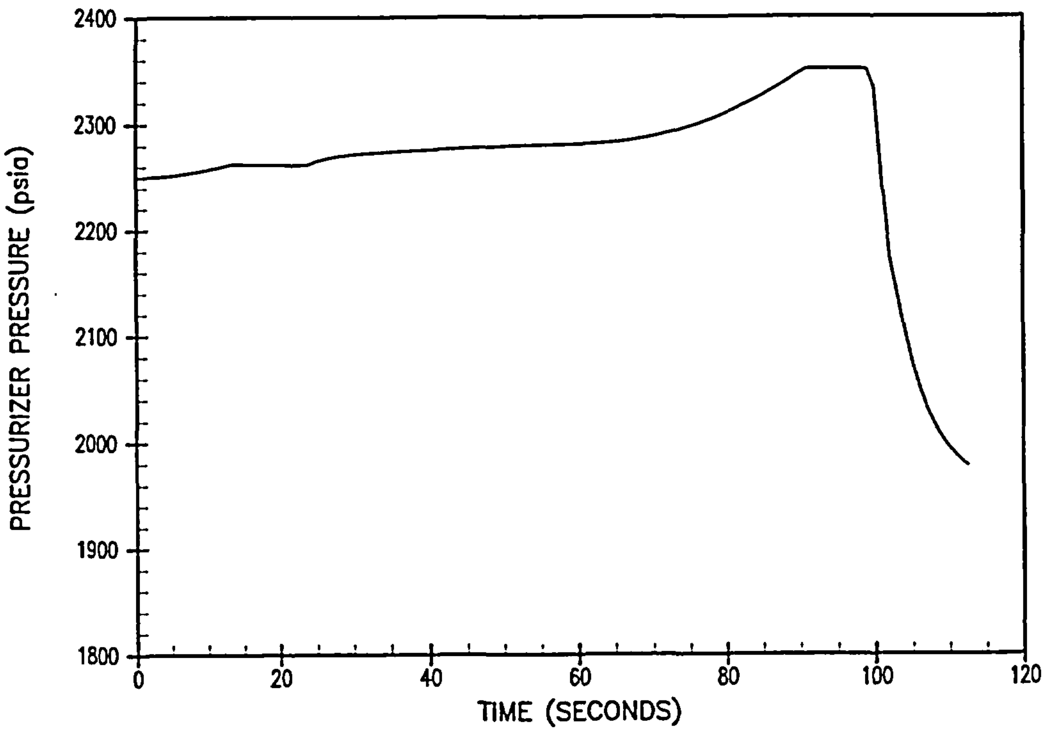


Figure 6.3-15

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Pressure vs. Time)

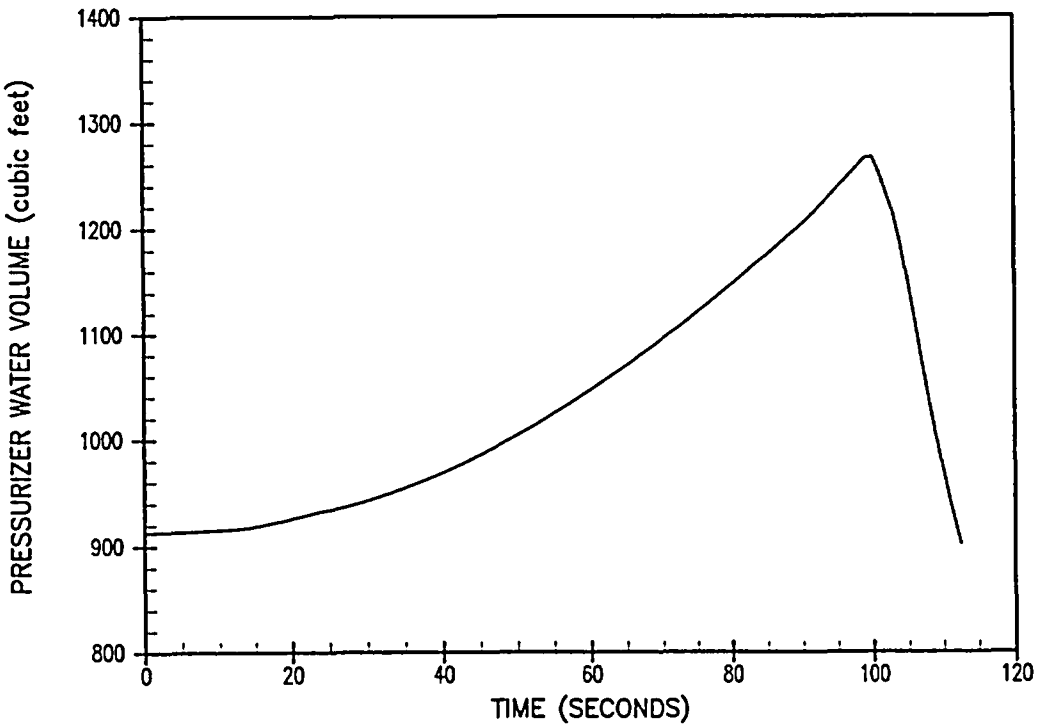


Figure 6.3-16

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (Pressurizer Water Volume vs. Time)

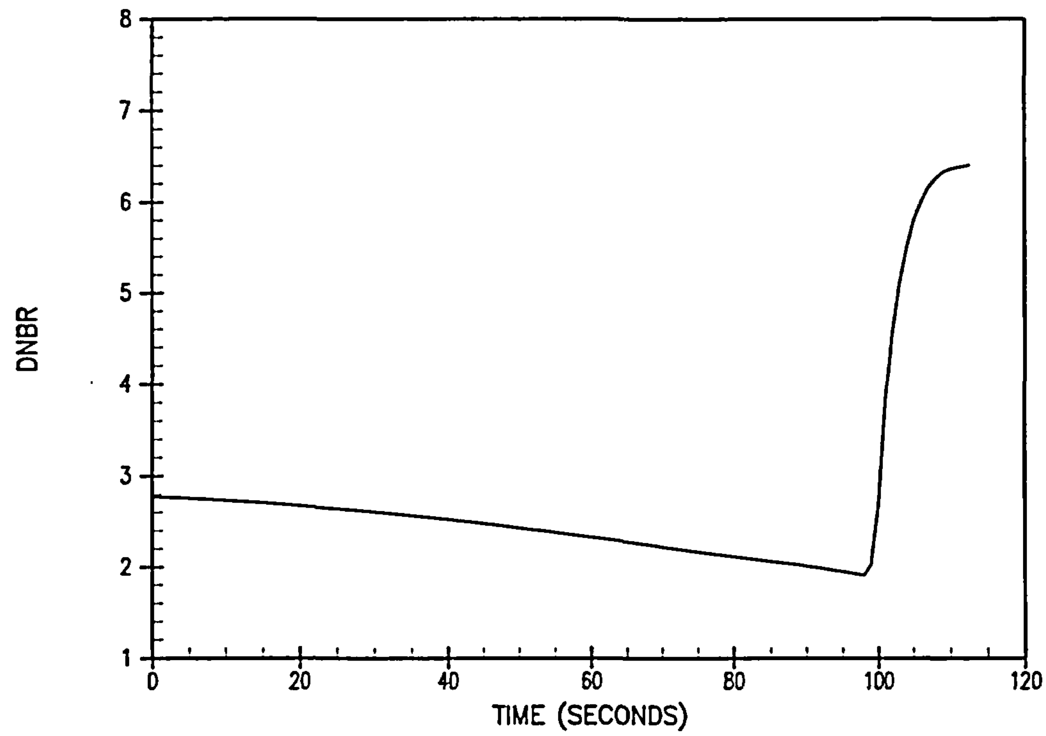


Figure 6.3-17

Uncontrolled RCCA Bank Withdrawal at Power Withdrawal Rate of 1 pcm/second

100% Power - Minimum Reactivity Feedback (DNBR vs. Time)

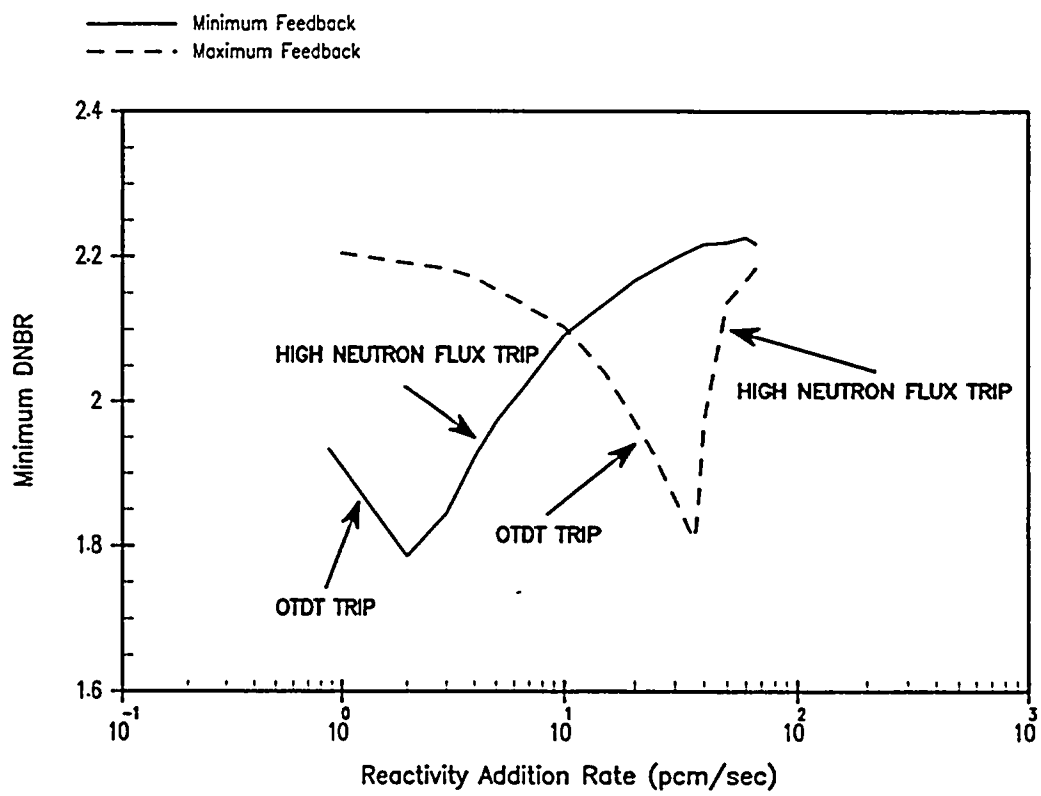


Figure 6.3-18

Uncontrolled RCCA Bank Withdrawal at 100% Power

Minimum DNBR versus Reactivity Insertion Rate

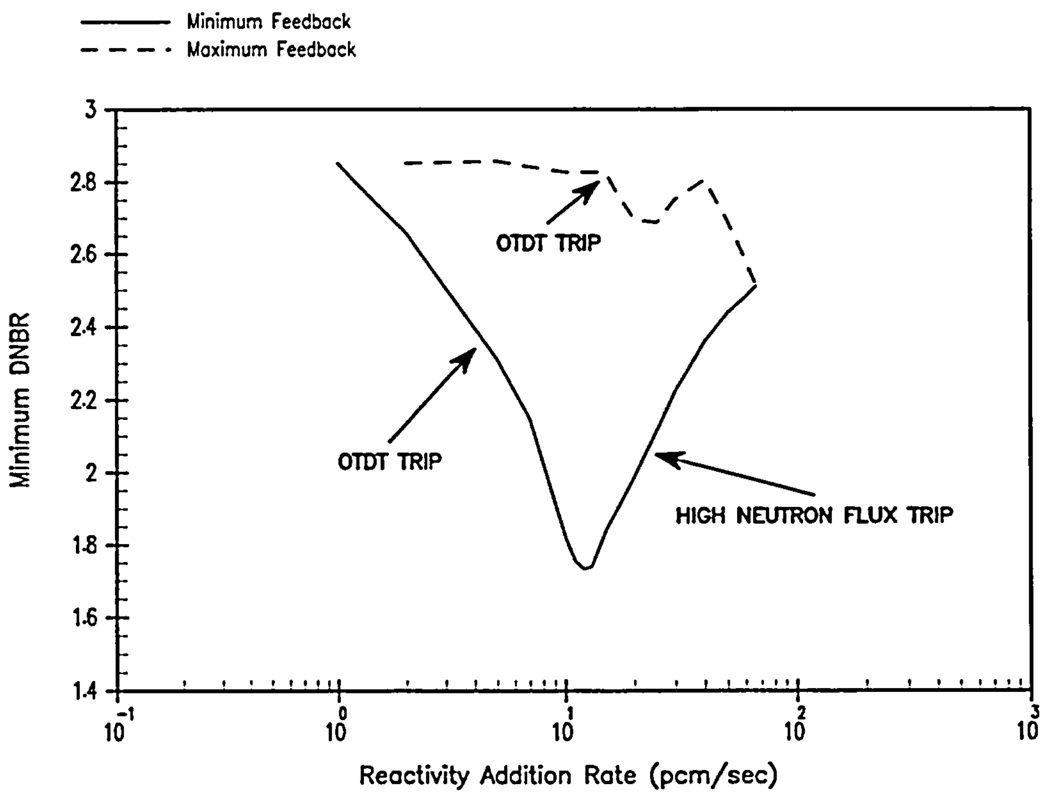


Figure 6.3.3-19

Uncontrolled RCCA Bank Withdrawal at 60% Power

Minimum DNBR vs. Reactivity Insertion Rate

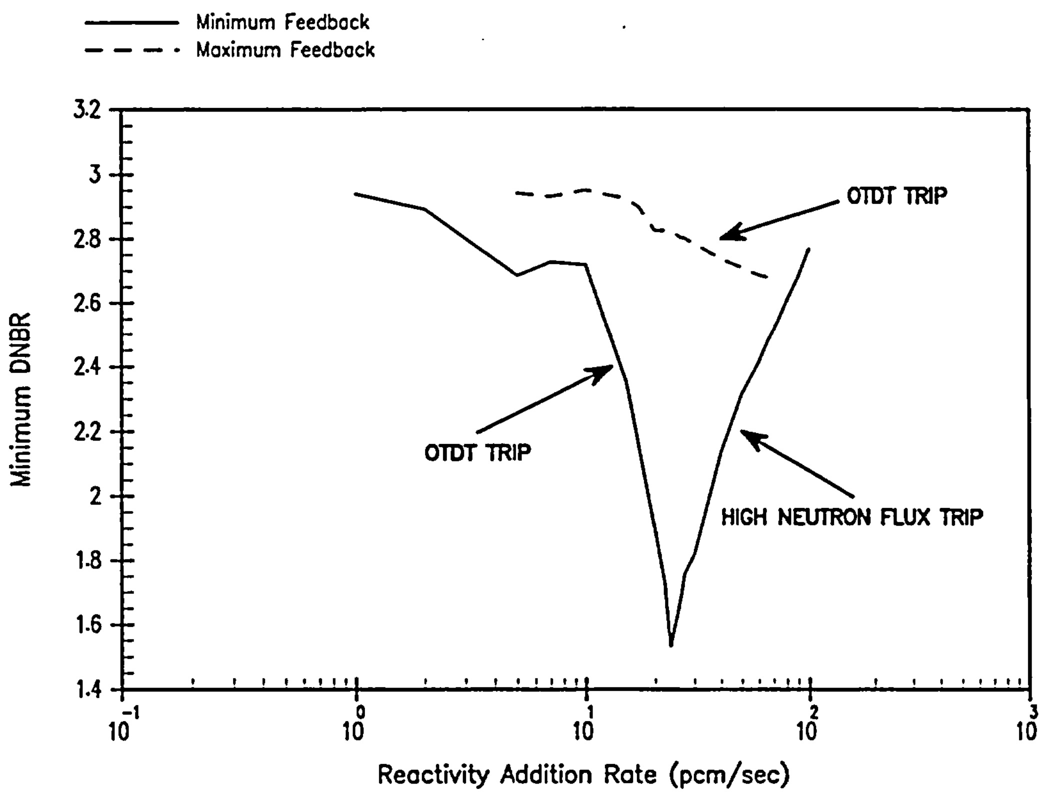


Figure 6.3-20

Uncontrolled RCCA Bank Withdrawal at 10% Power

Minimum DNBR vs. Reactivity Insertion Rate

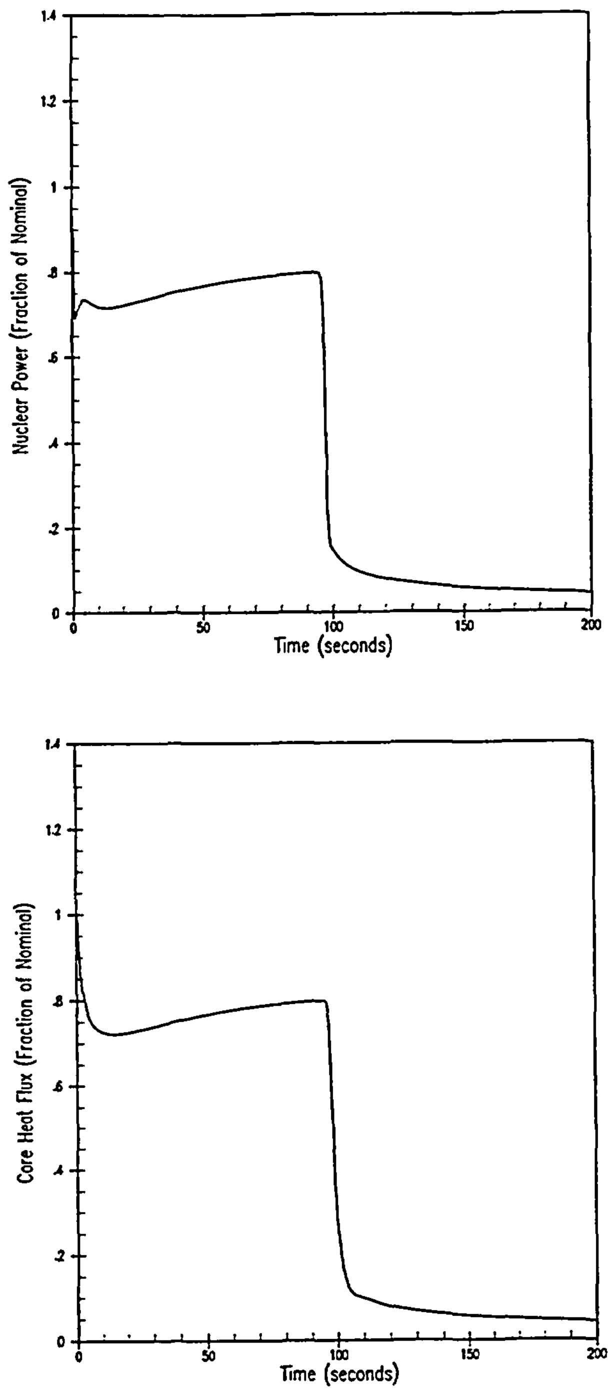
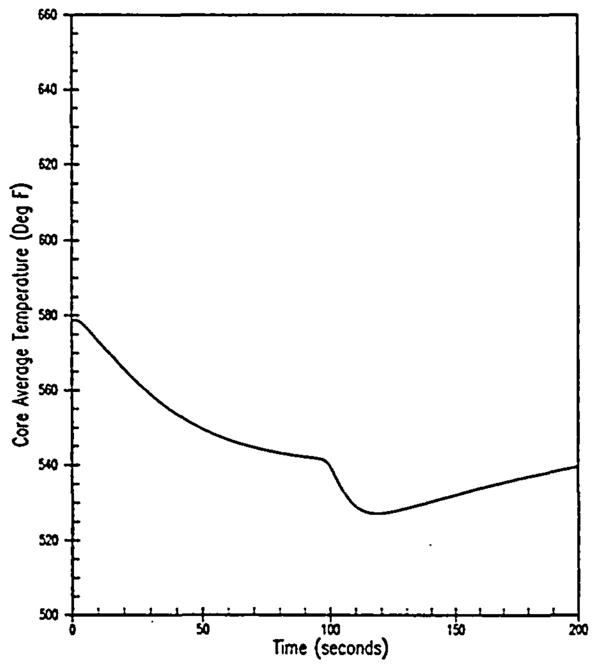


Figure 6.3-21

Dropped Rod Transient with Manual Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)



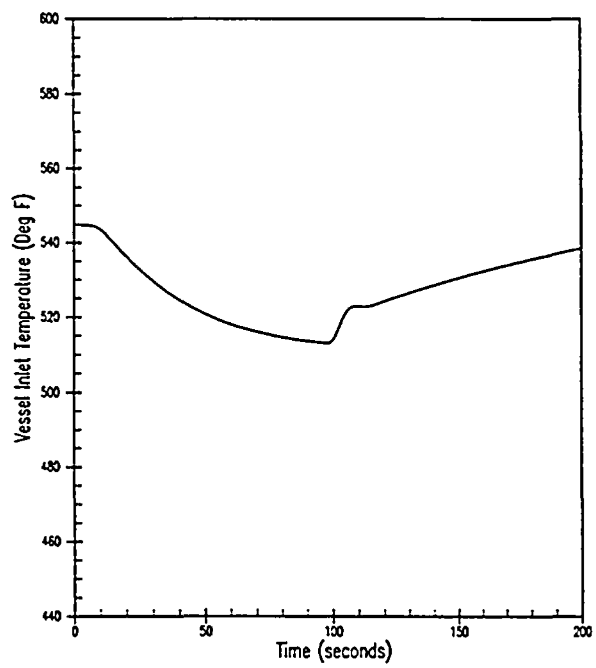


Figure 6.3-22

Dropped Rod Transient with Manual Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)

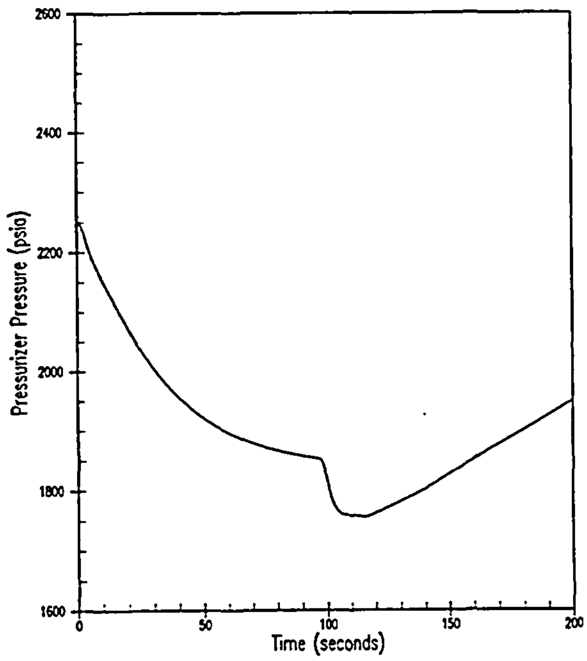


Figure 6.3-23

Dropped Rod Transient with Manual Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 400 pcm at BOL (small negative MTC)

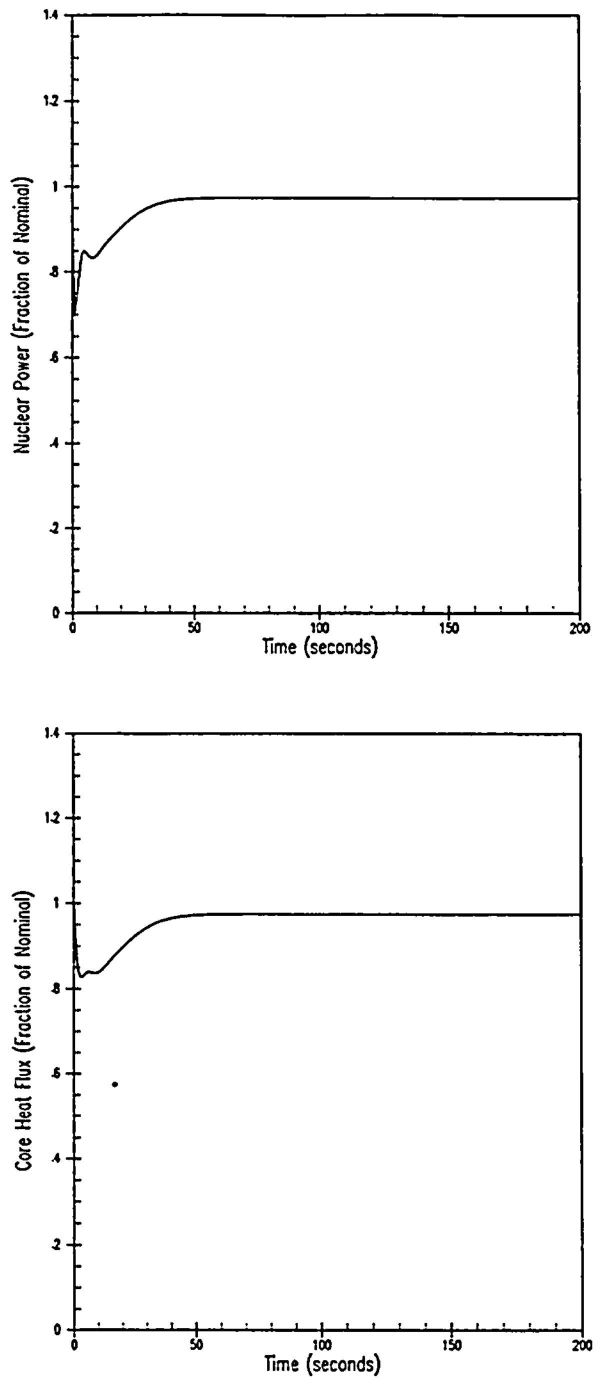


Figure 6.3-24

Dropped Rod Transient with Manual Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)

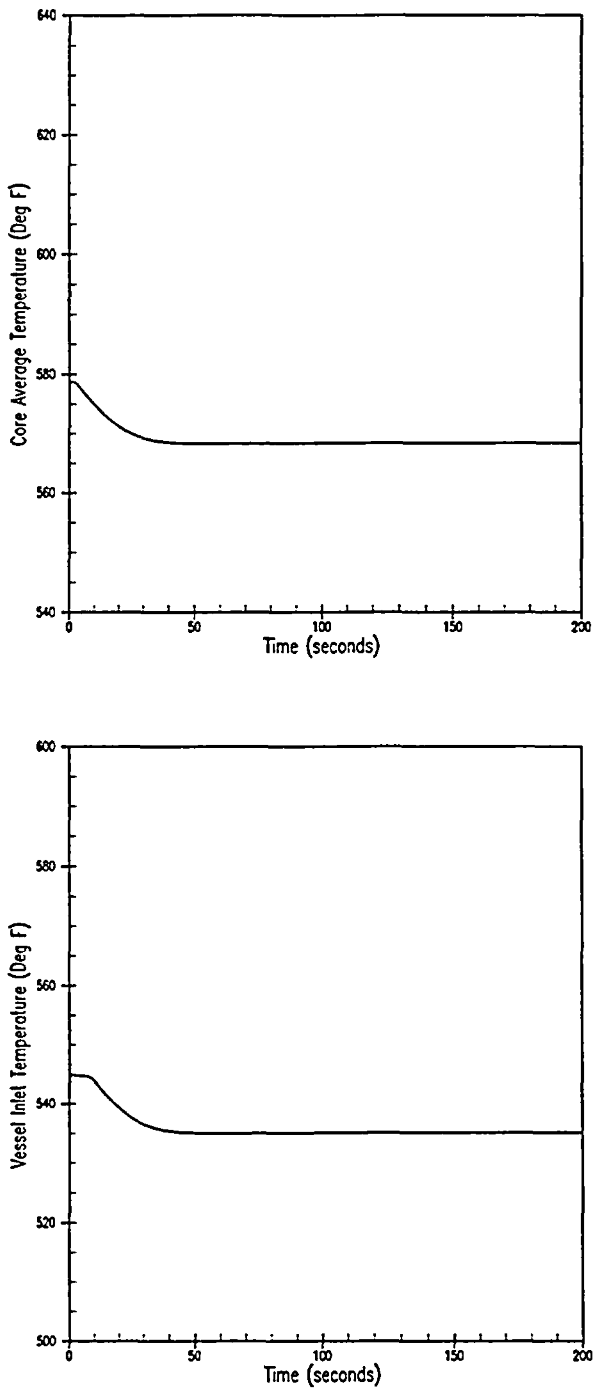


Figure 6.3-25

Dropped Rod Transient with Manual Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)

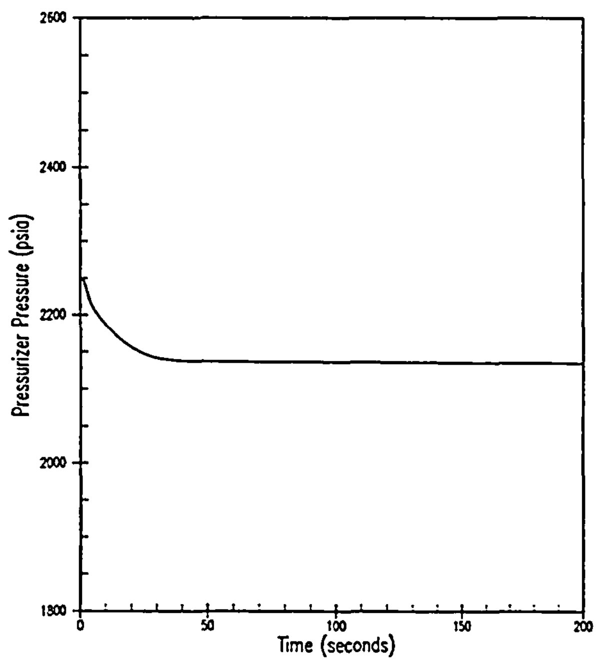


Figure 6.3-26

Dropped Rod Transient with Manual Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 400 pcm at EOL (large negative MTC)

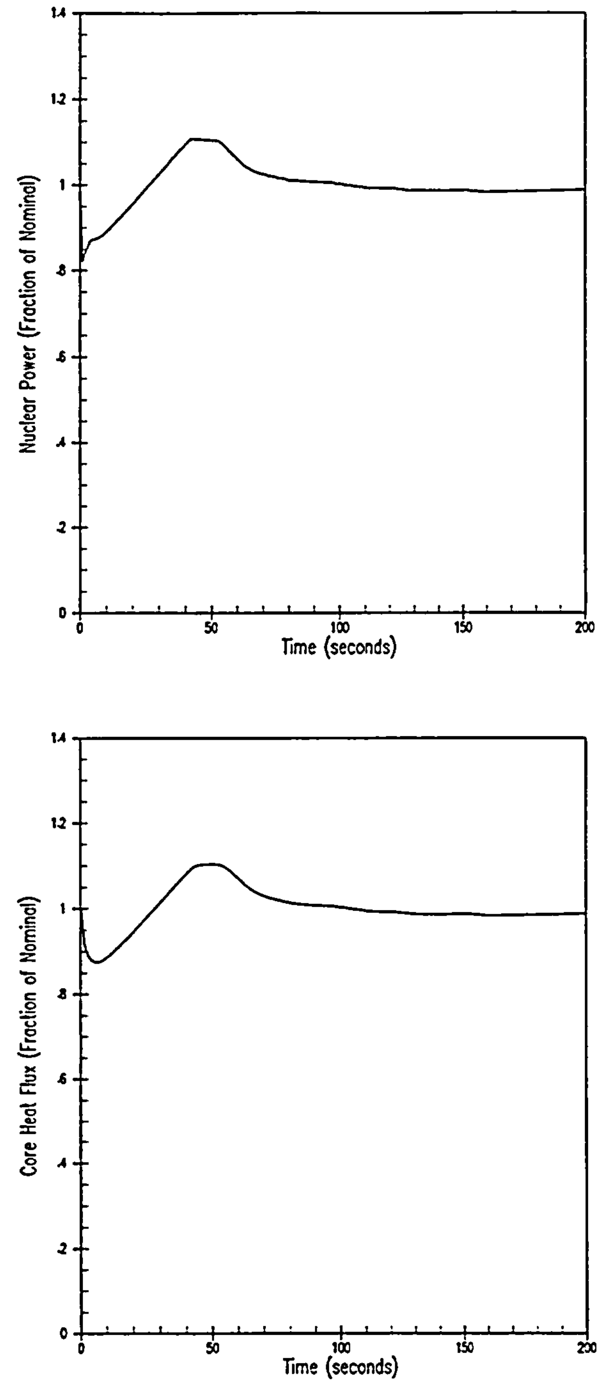


Figure 6.3-27

Dropped Rod Transient with Automatic Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

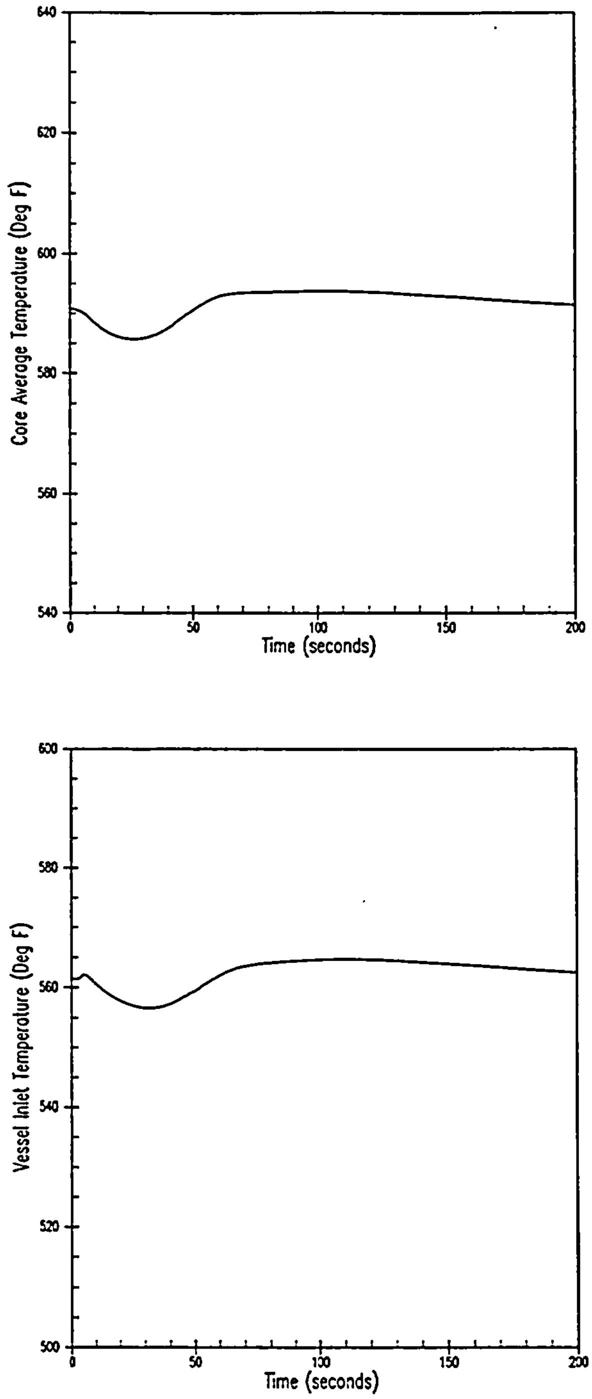


Figure 6.3-28

Dropped Rod Transient with Automatic Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

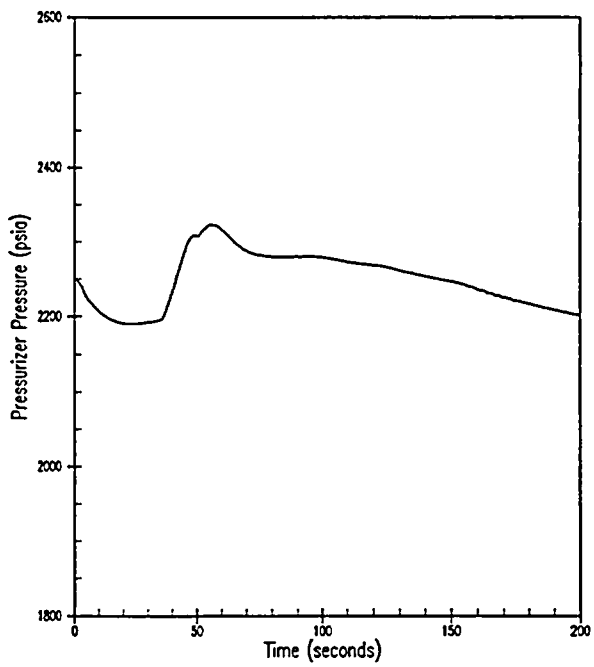


Figure 6.3-29

Dropped Rod Transient with Automatic Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 200 pcm at BOL (small negative MTC)

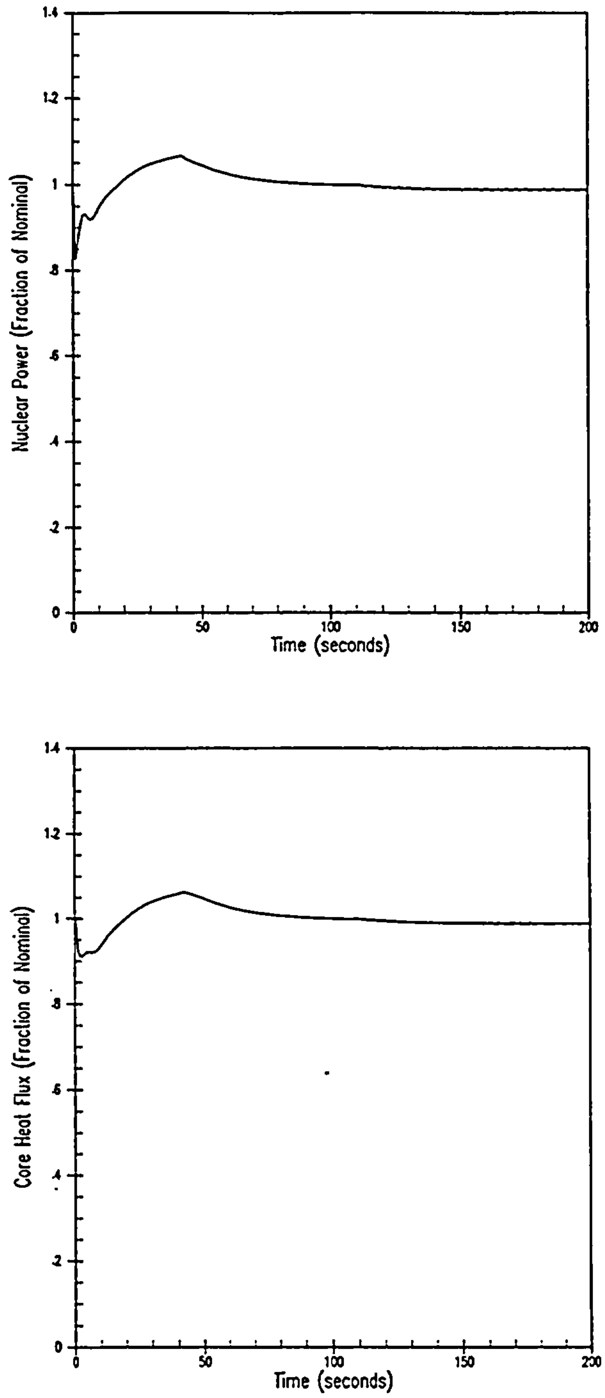


Figure 6.3-30

Dropped Rod Transient with Automatic Rod Control, Nuclear Power and Core Heat Flux for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)

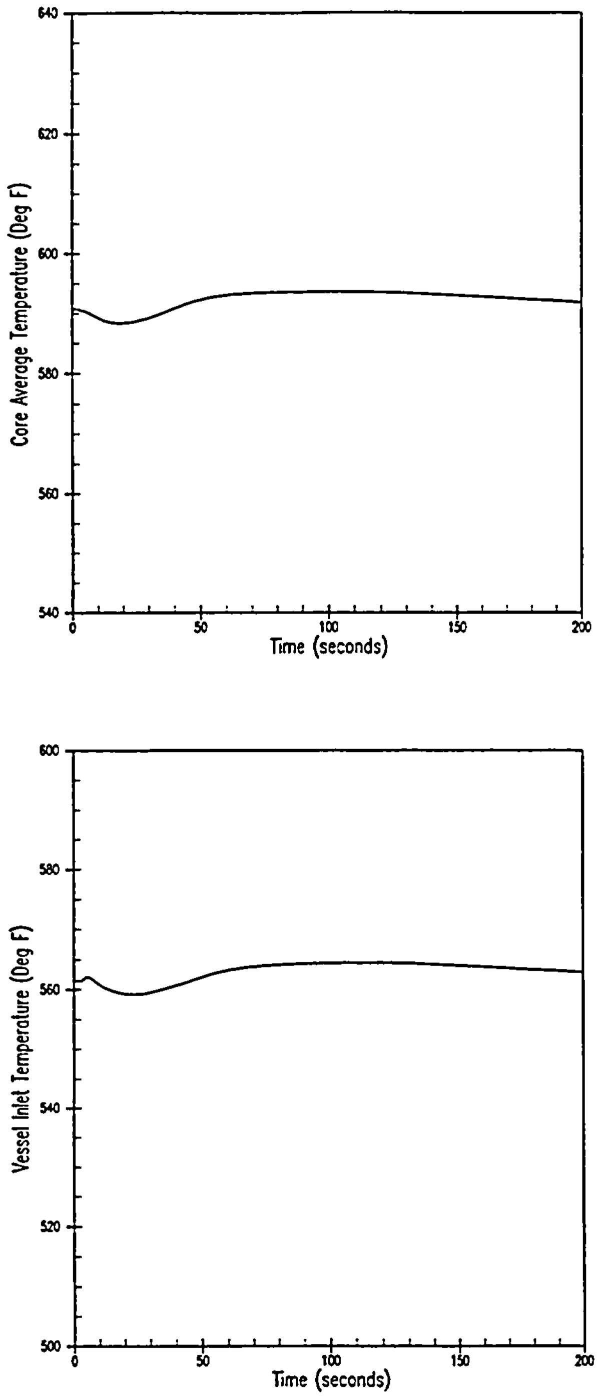


Figure 6.3-31

Dropped Rod Transient with Automatic Rod Control, Core Average and Vessel Inlet Temperature for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)

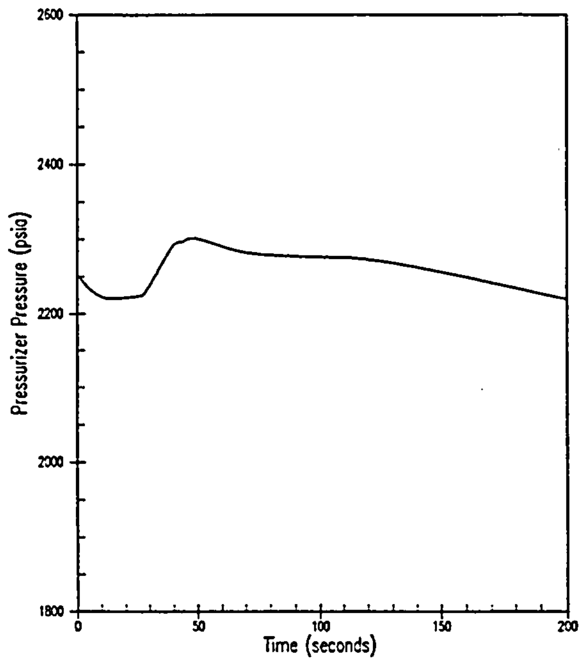


Figure 6.3-32

Dropped Rod Transient with Automatic Rod Control, Pressurizer Pressure for Dropped RCCA Worth of 200 pcm at EOL (large negative MTC)

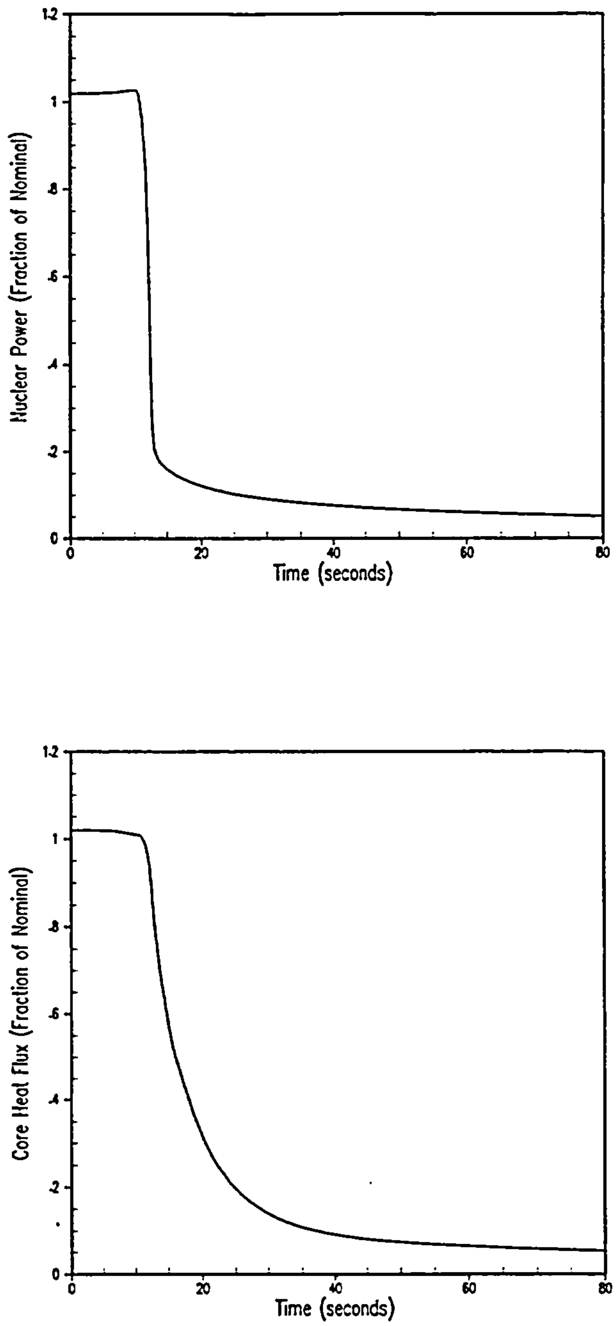
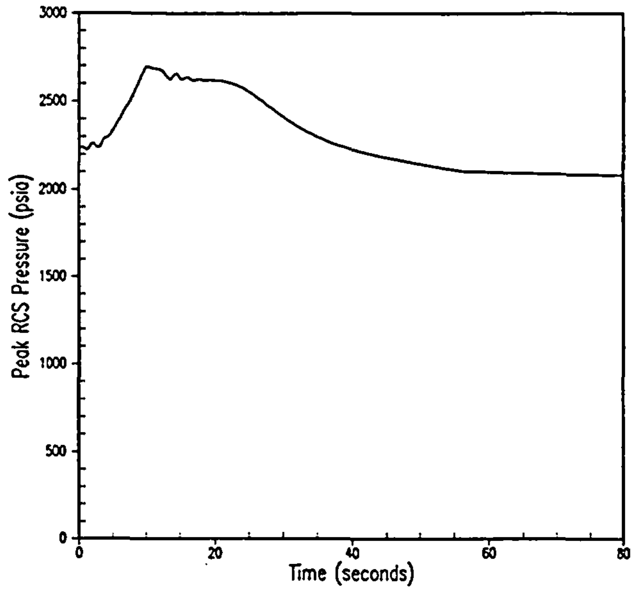


Figure 6.3-33

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Nuclear Power and Core Heat Flux



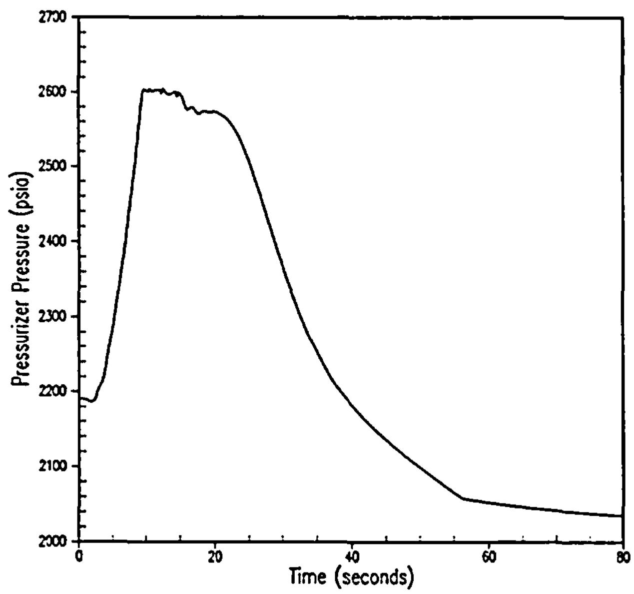


Figure 6.3-34

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Peak RCS Pressure and Pressurizer Pressure

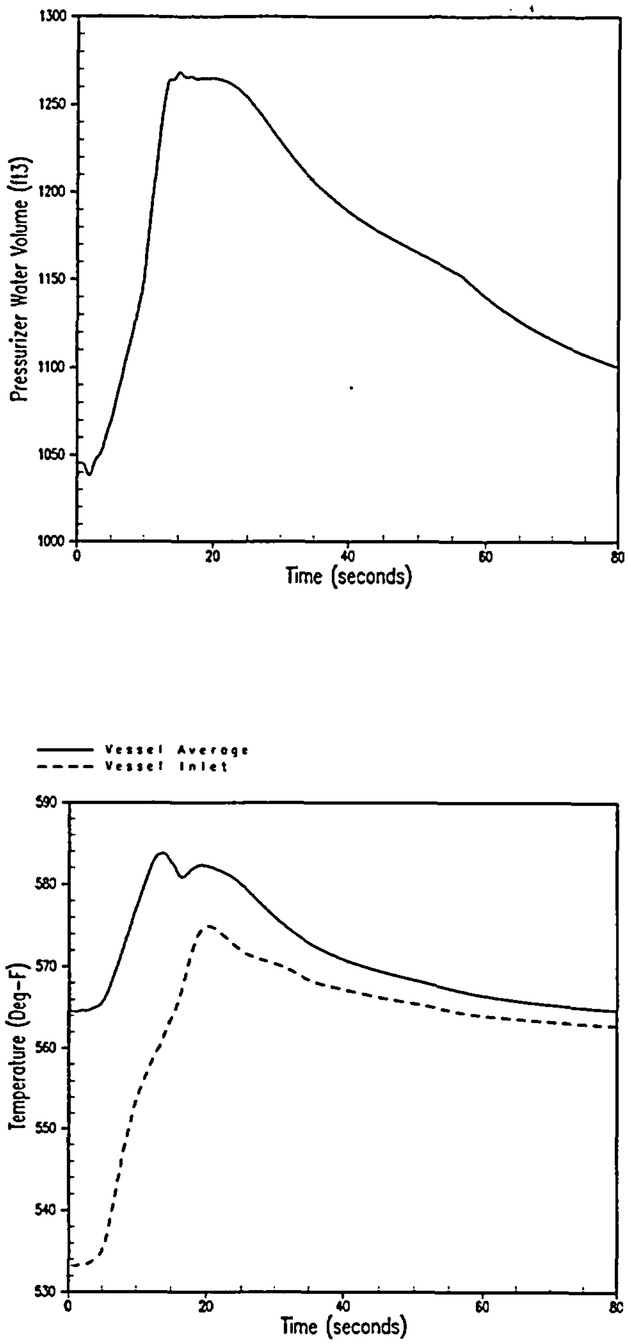


Figure 6.3-35

Loss-of-Load/Turbine Trip, Peak RCS Pressure Case – Pressurizer Water Volume and Vessel Average & Vessel Inlet Temperature

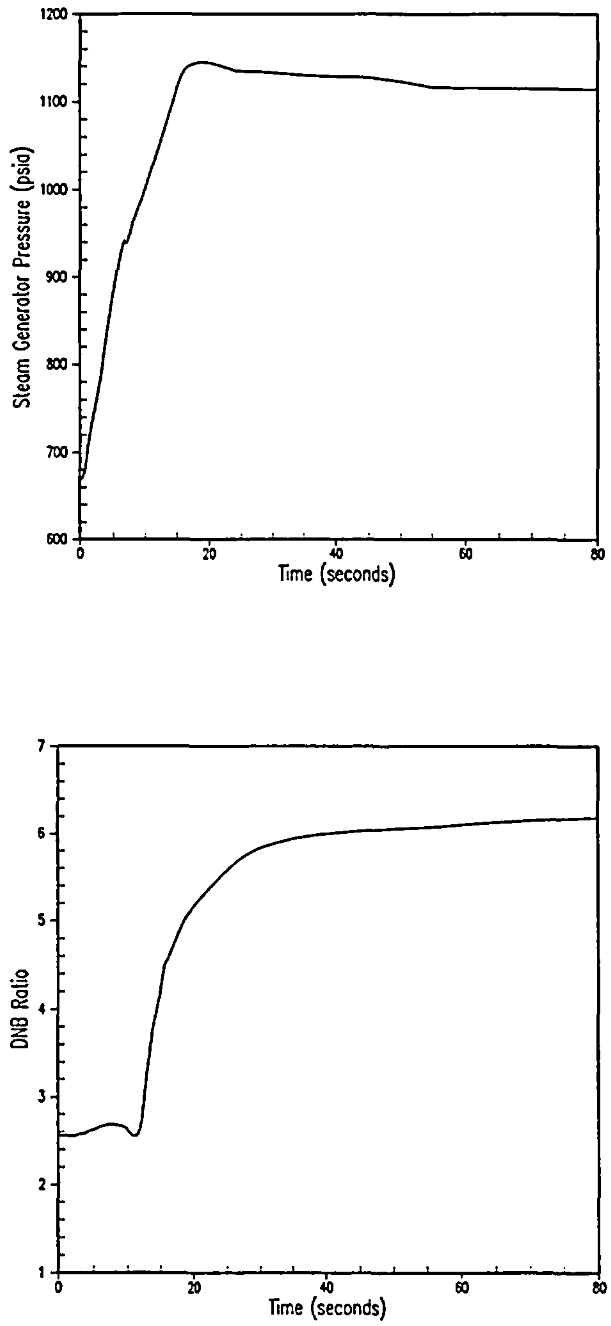


Figure 6.3-36

Loss-of-Load/Turbine Trip, Peak RCS Pressure – Steam Generator Pressure and DNBR

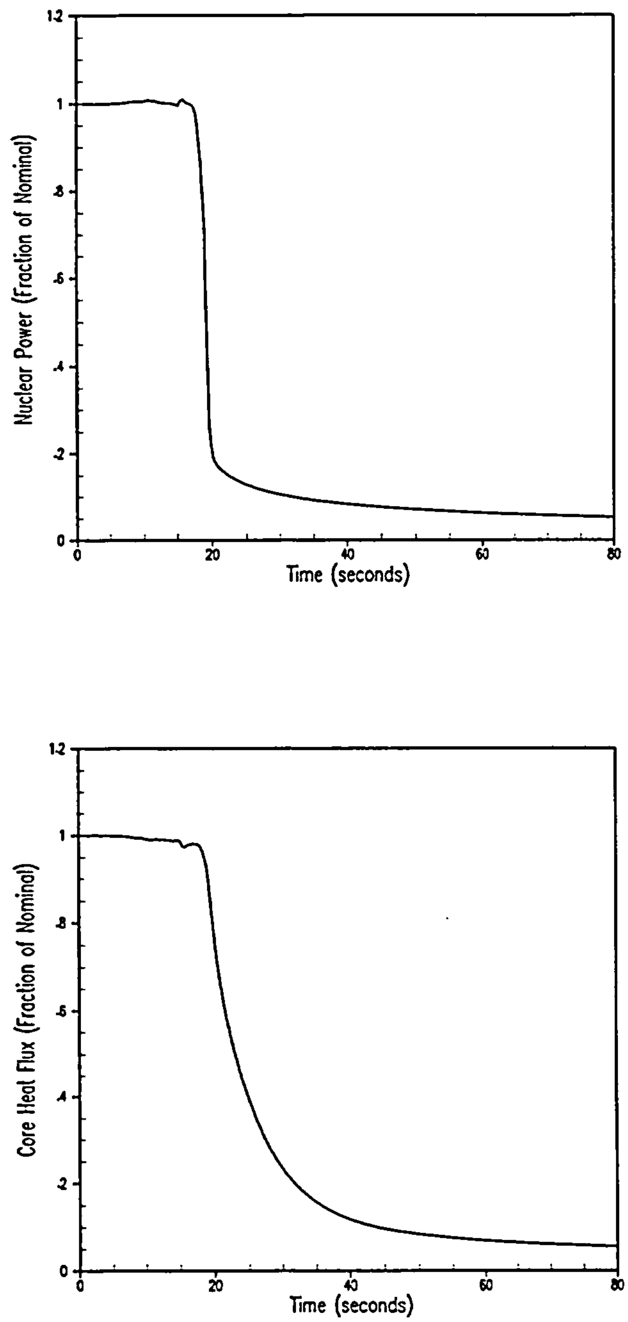
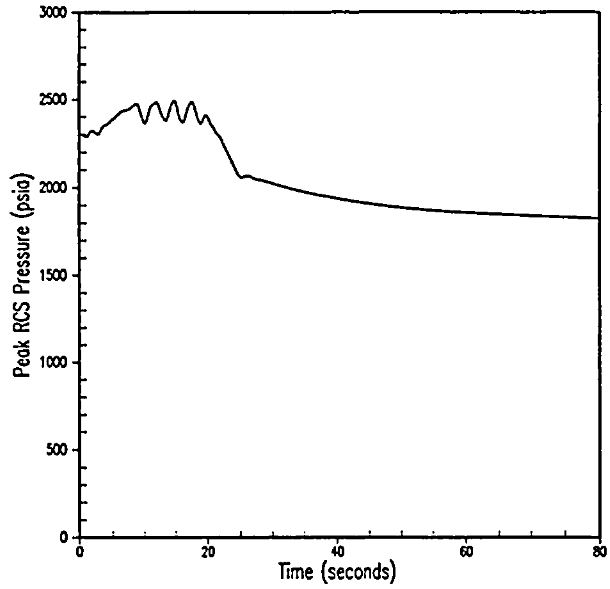


Figure 6.3-37

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Nuclear Power and Core Heat Flux



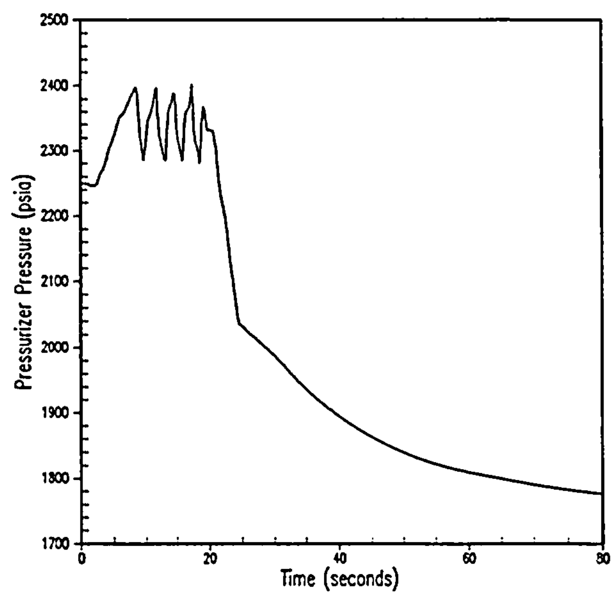
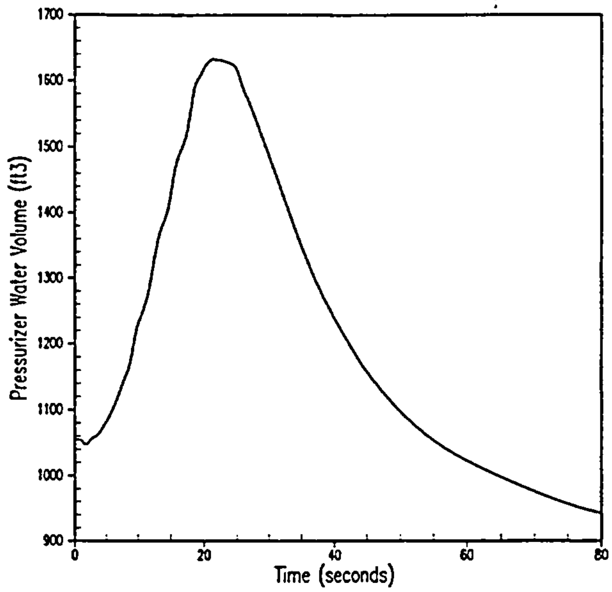


Figure 6.3-38

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Peak RCS Pressure and Pressurizer Pressure



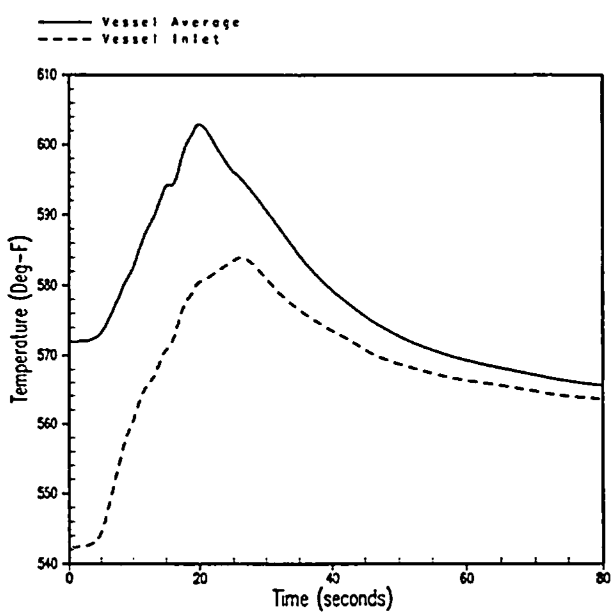
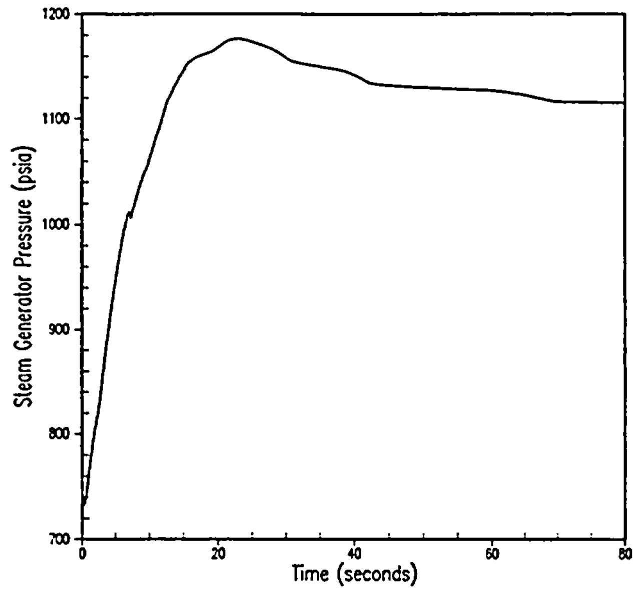


Figure 6.3-39

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Pressurizer Water Volume and Vessel Average & Vessel Inlet Temperature



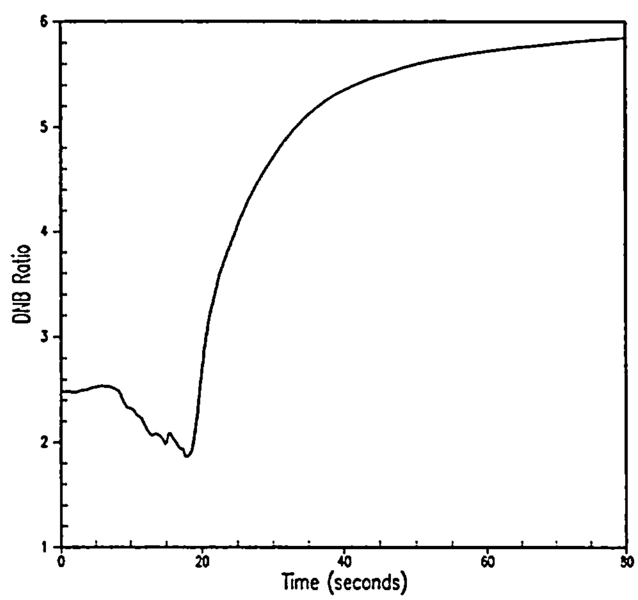


Figure 6.3-40

Loss-of-Load/Turbine Trip, Minimum DNBR Case – Steam Generator Pressure and DNBR

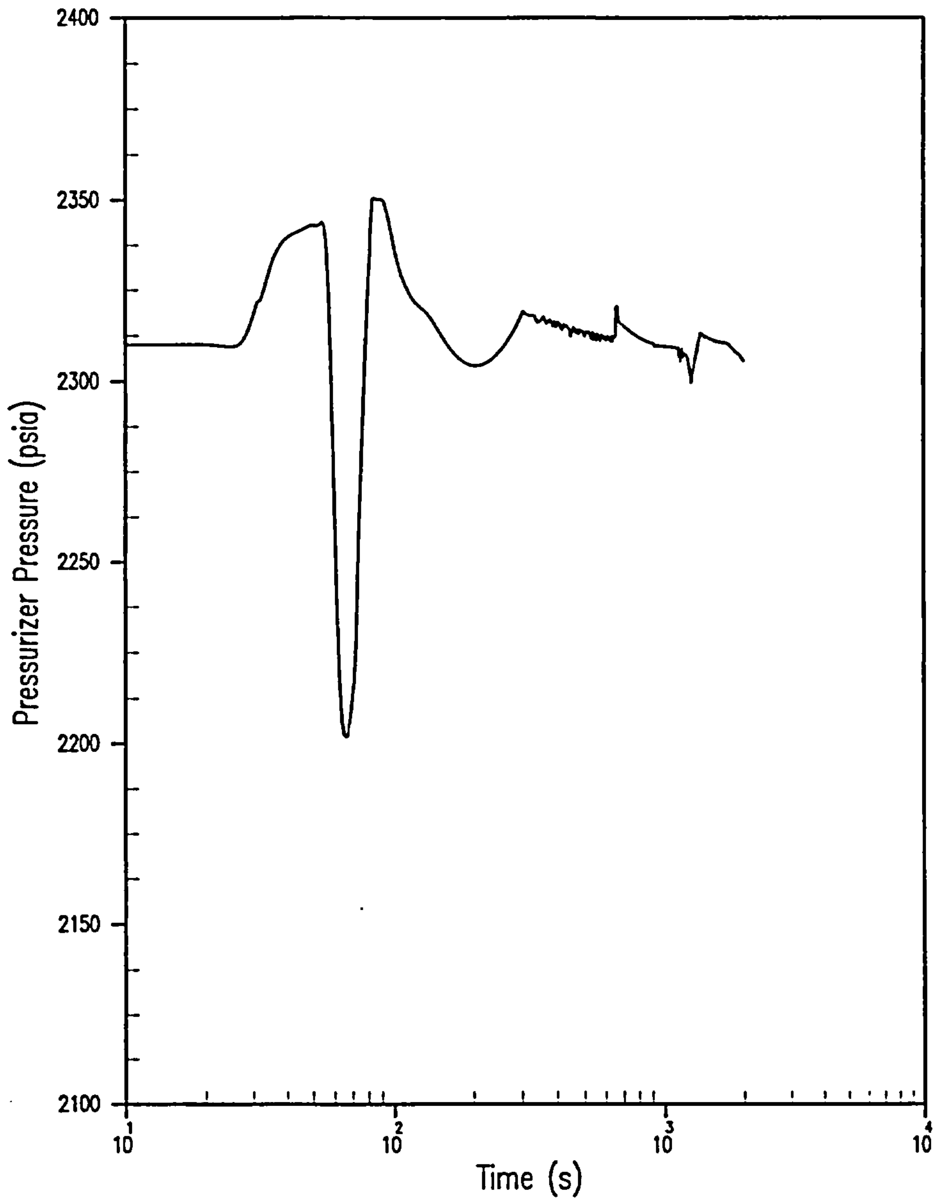


Figure 6.3-41

LONF (Pressurizer Pressure vs. Time)

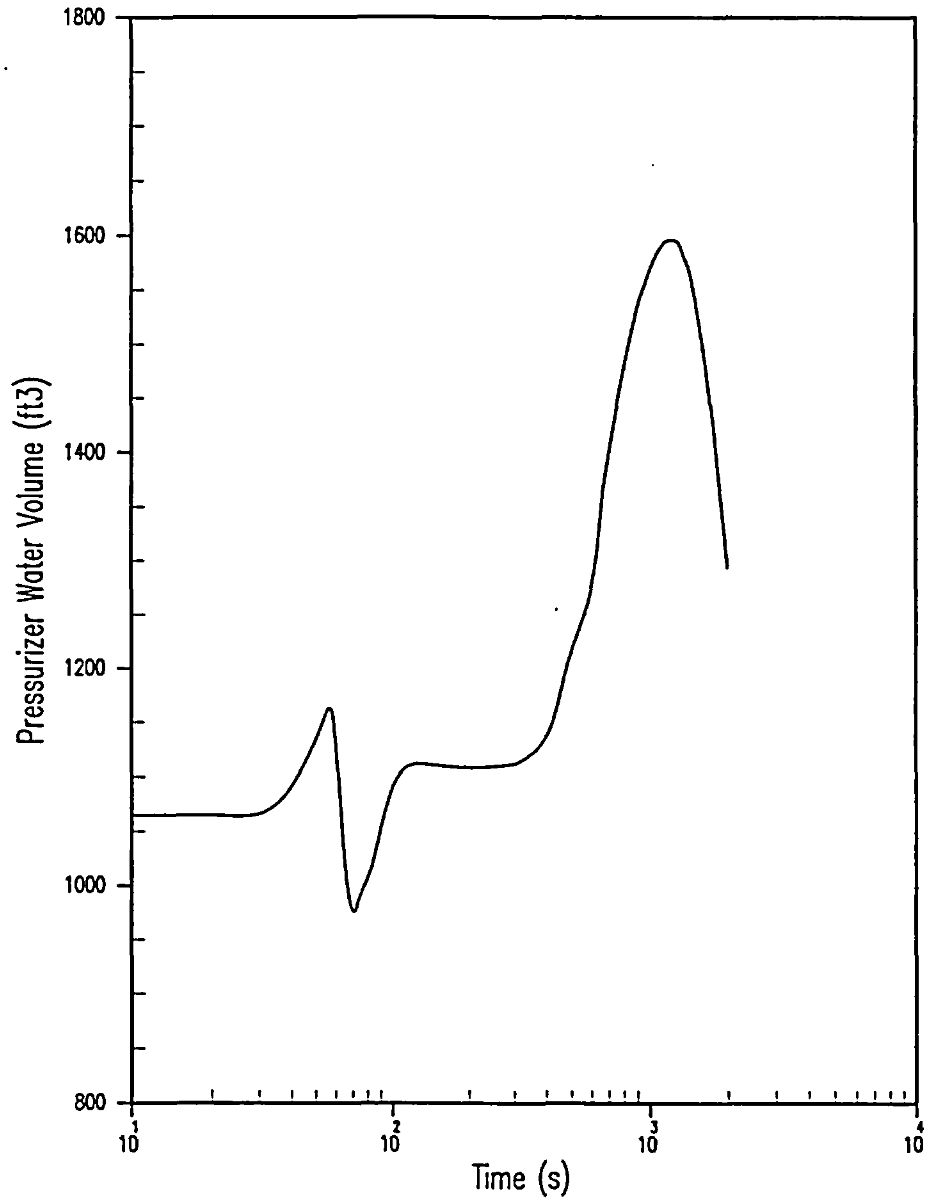


Figure 6.3-42

LONF (Pressurizer Water Volume vs. Time)

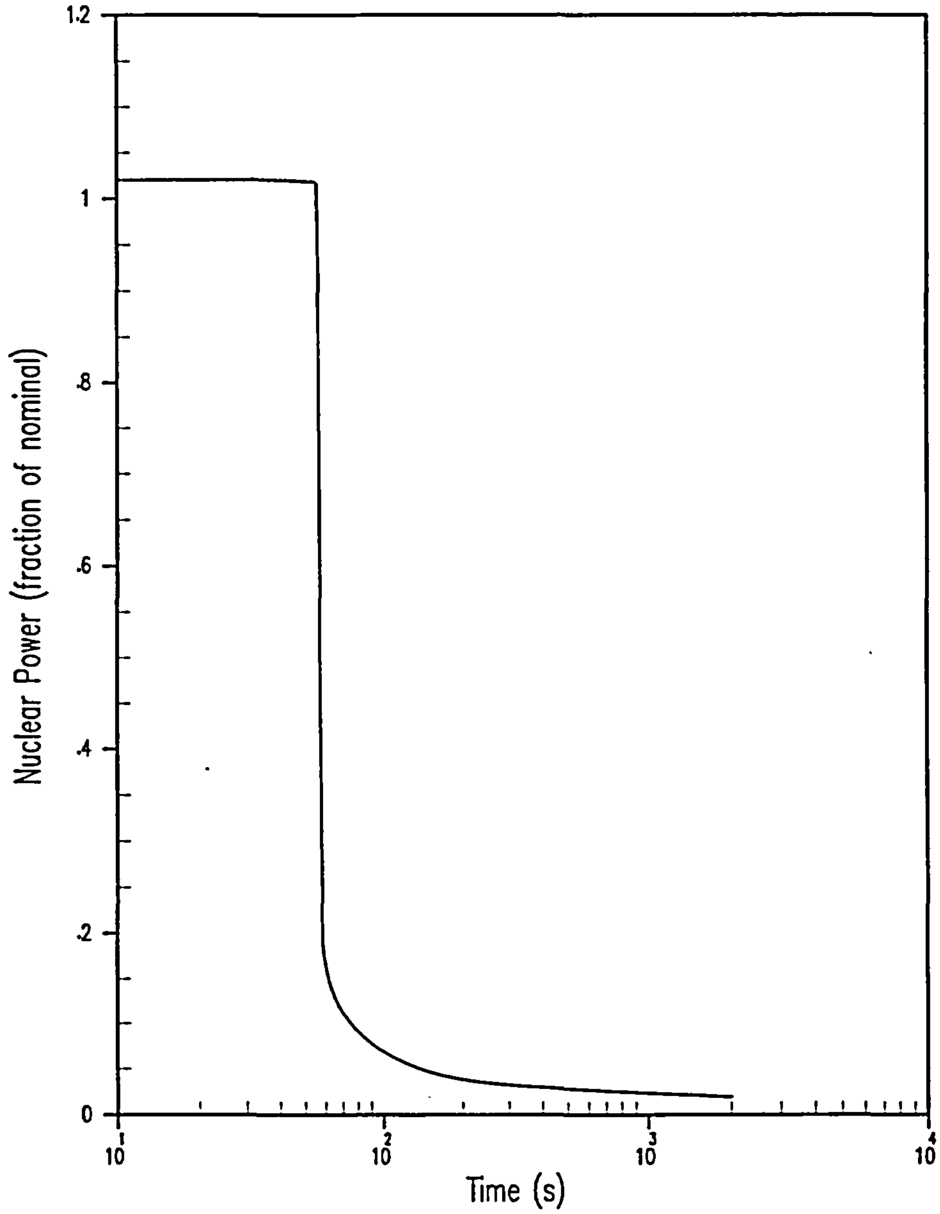


Figure 6.3-43

LONF (Nuclear Power vs. Time)

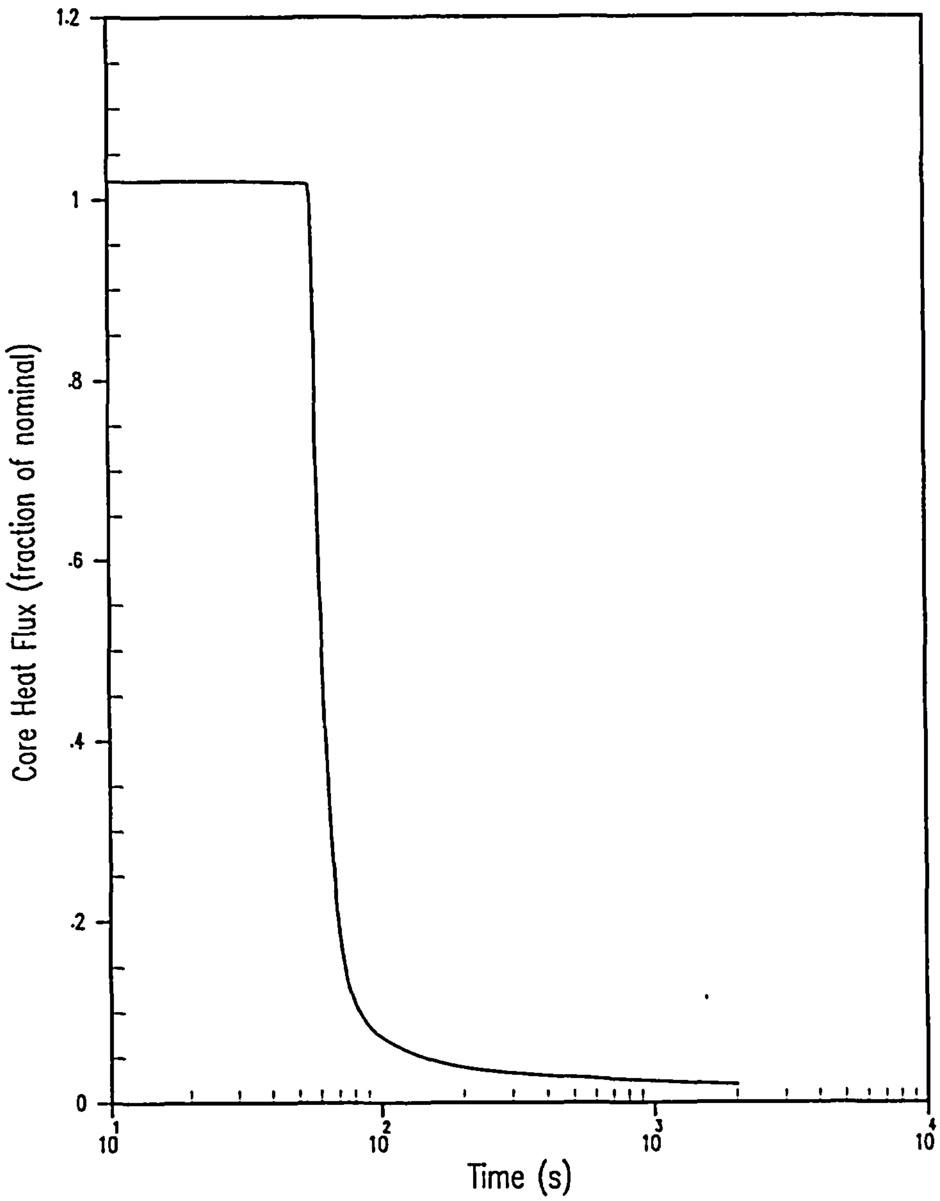


Figure 6.3-44

LONF (Core Heat Flux vs. Time)

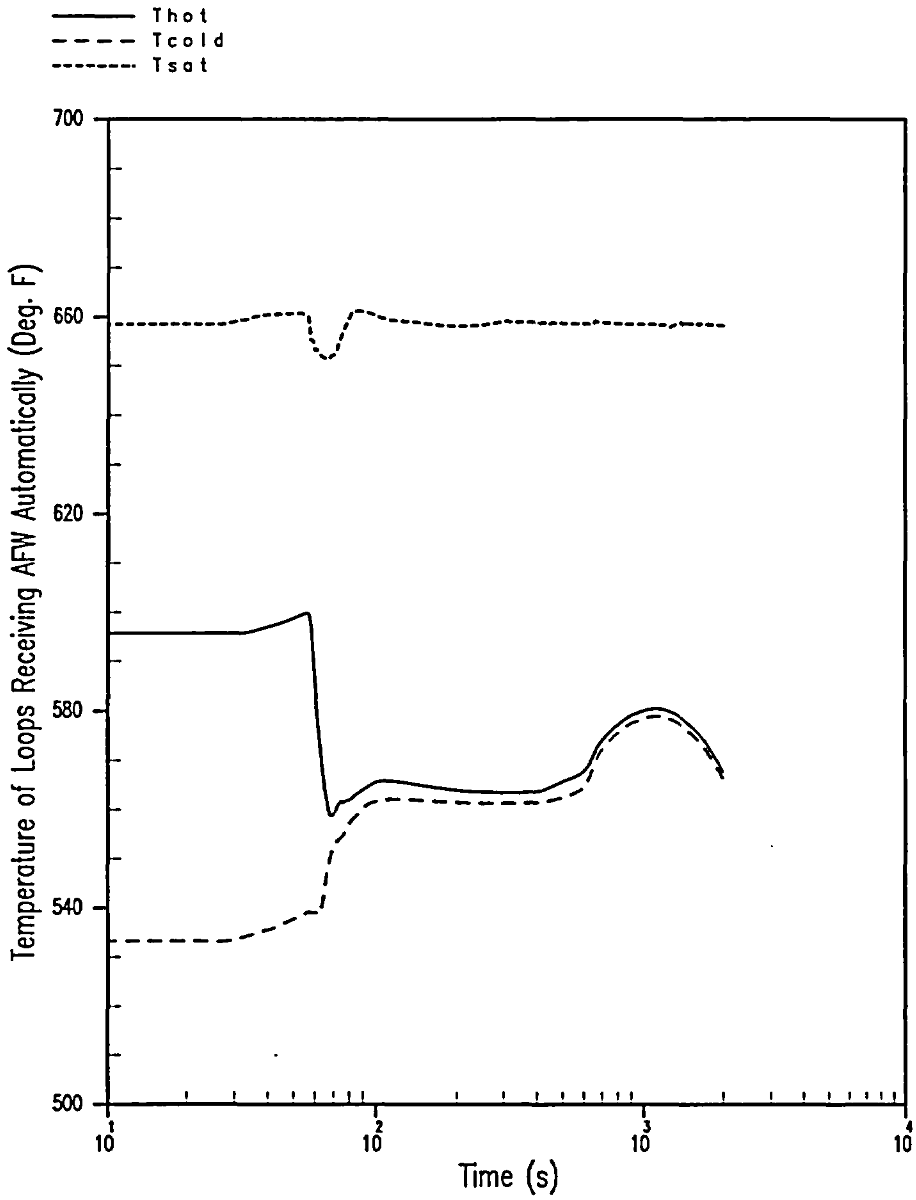


Figure 6.3-45

LONF (RCS Temperatures for Loops Receiving Automatic AFW Flow vs. Time)

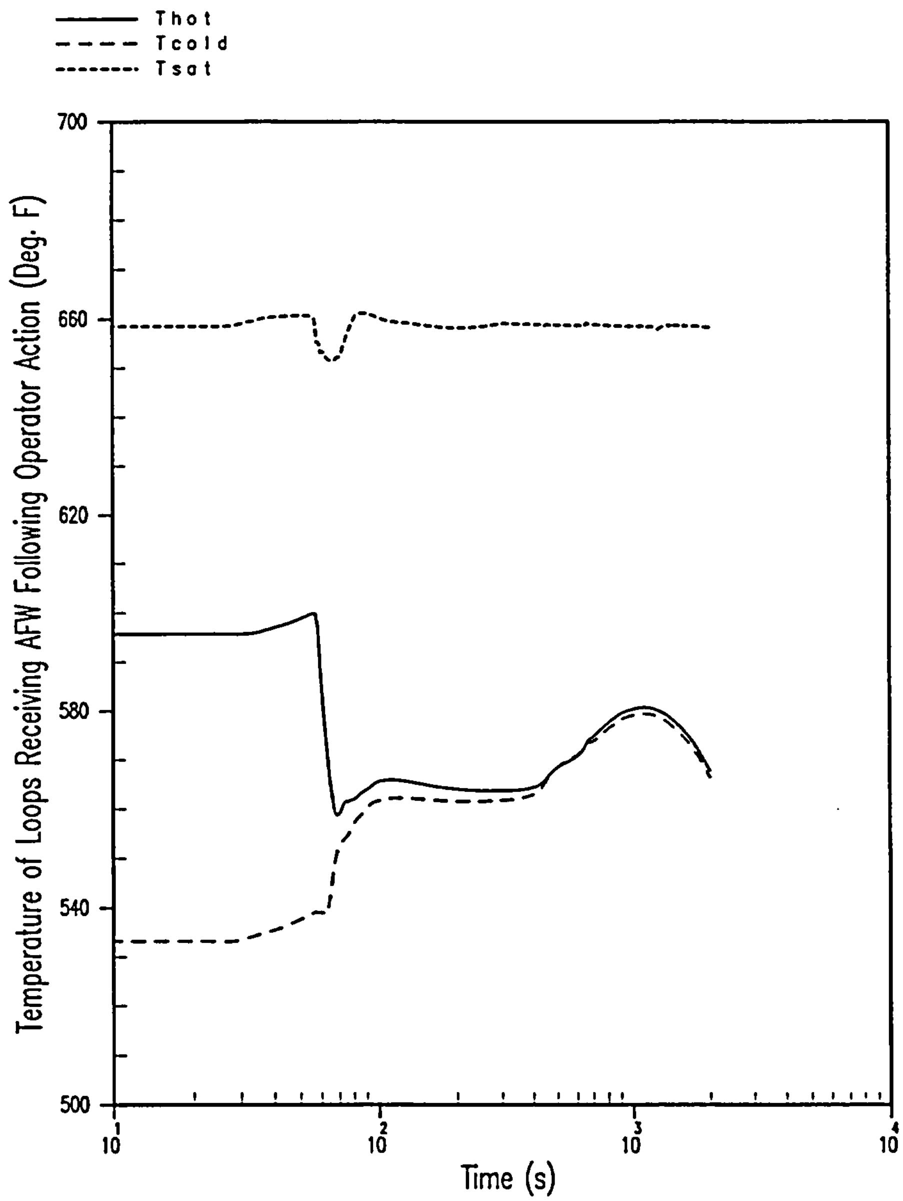


Figure 6.3-46

LONF (RCS Temperatures for Loops Receiving AFW Flow Following Operator Action vs. Time)

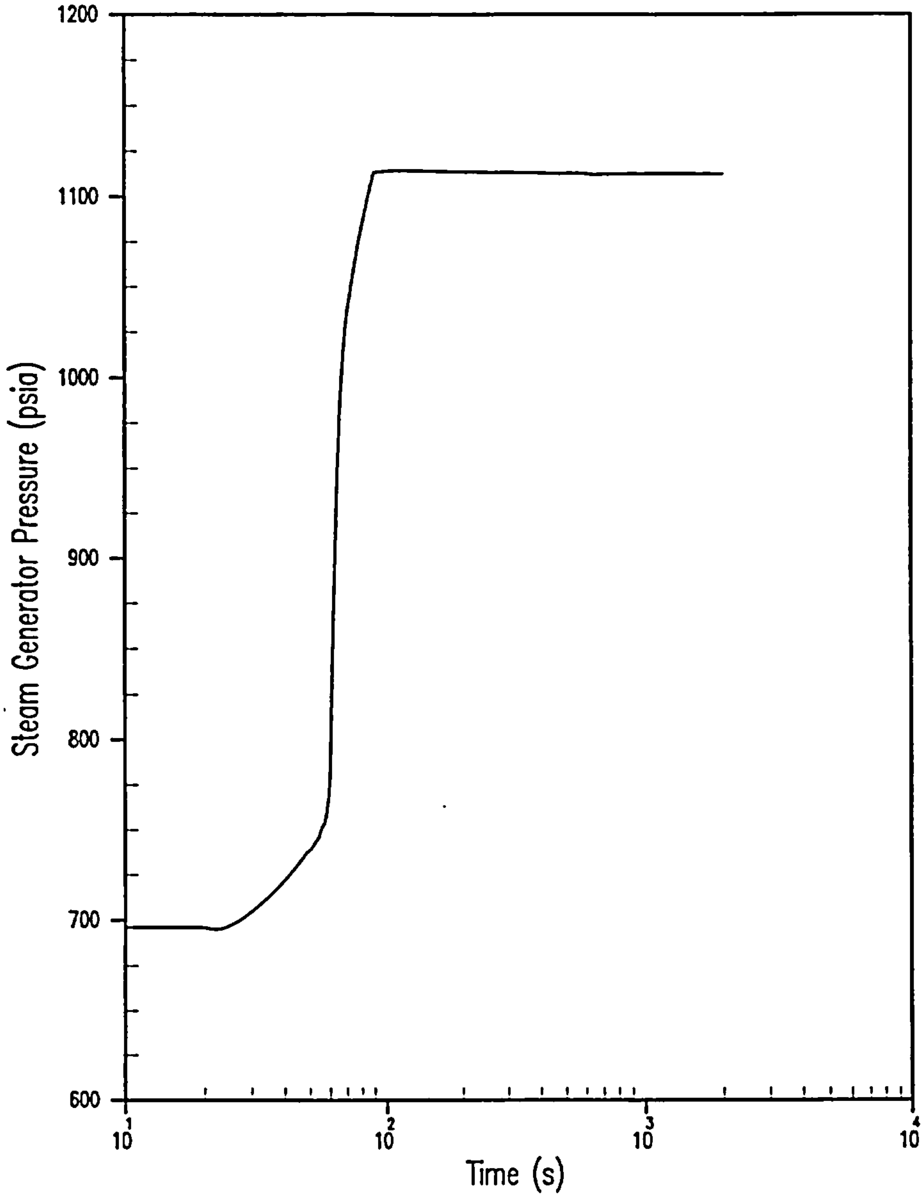


Figure 6.3-47

LONF (Steam Generator Pressure vs. Time)

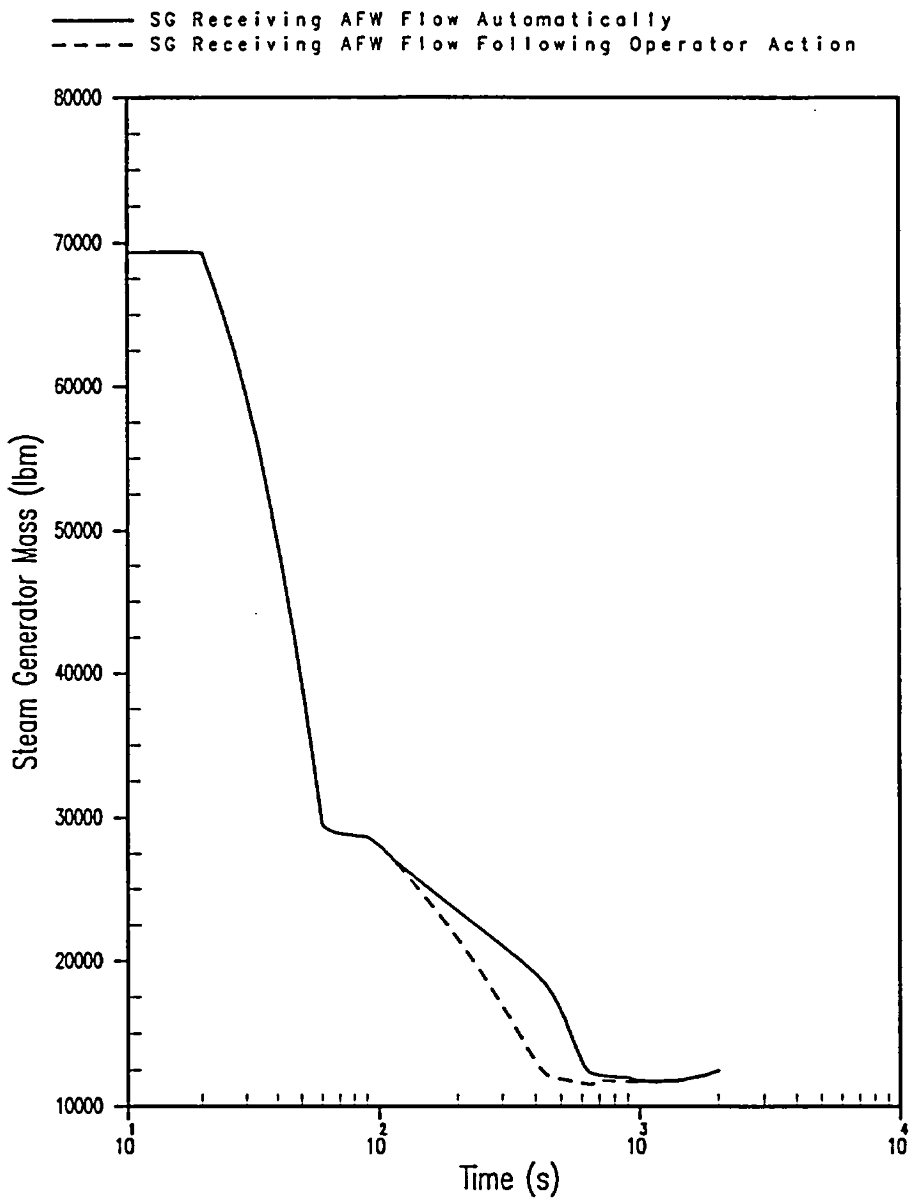


Figure 6.3-48

LONF (Steam Generator Mass vs. Time)

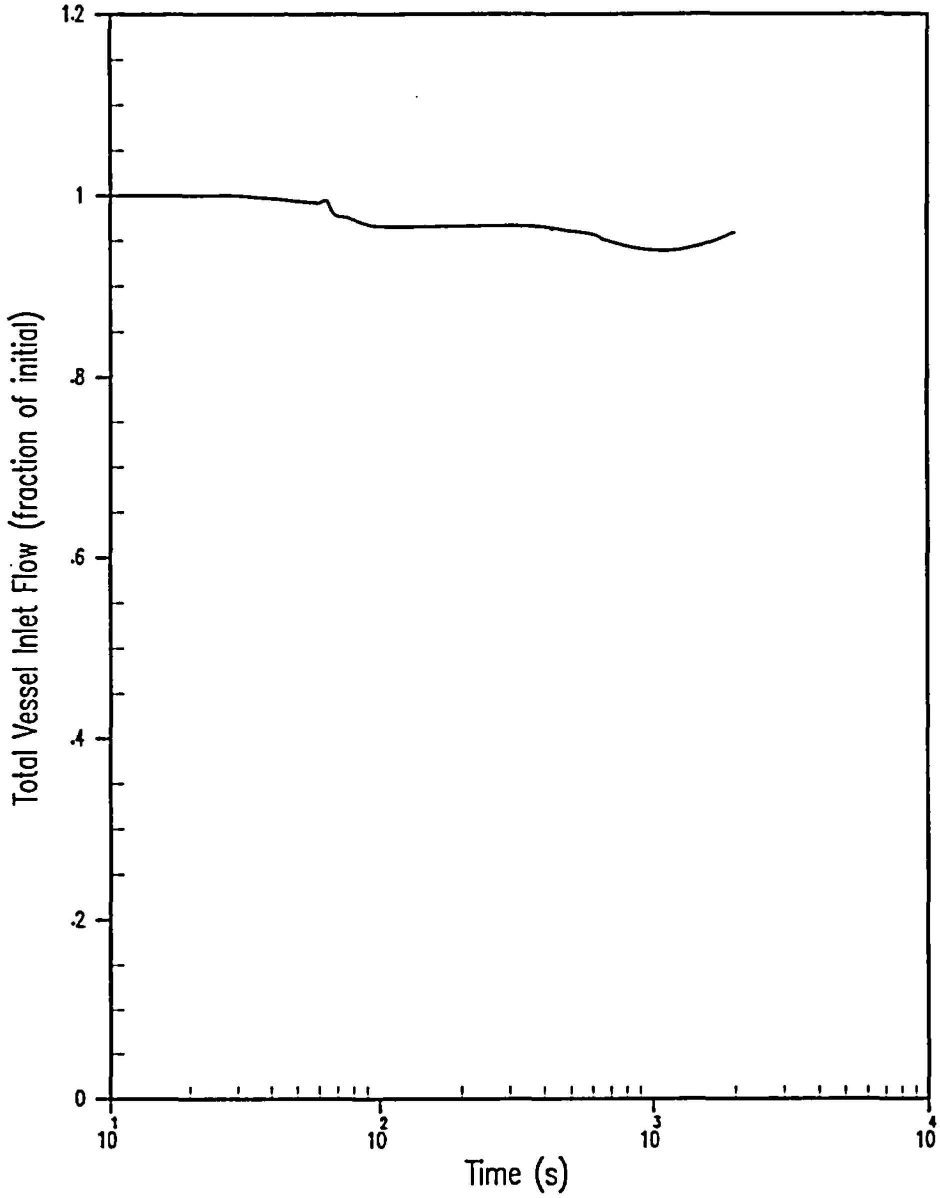


Figure 6.3-49

LONF (Total RCS Flow vs. Time)

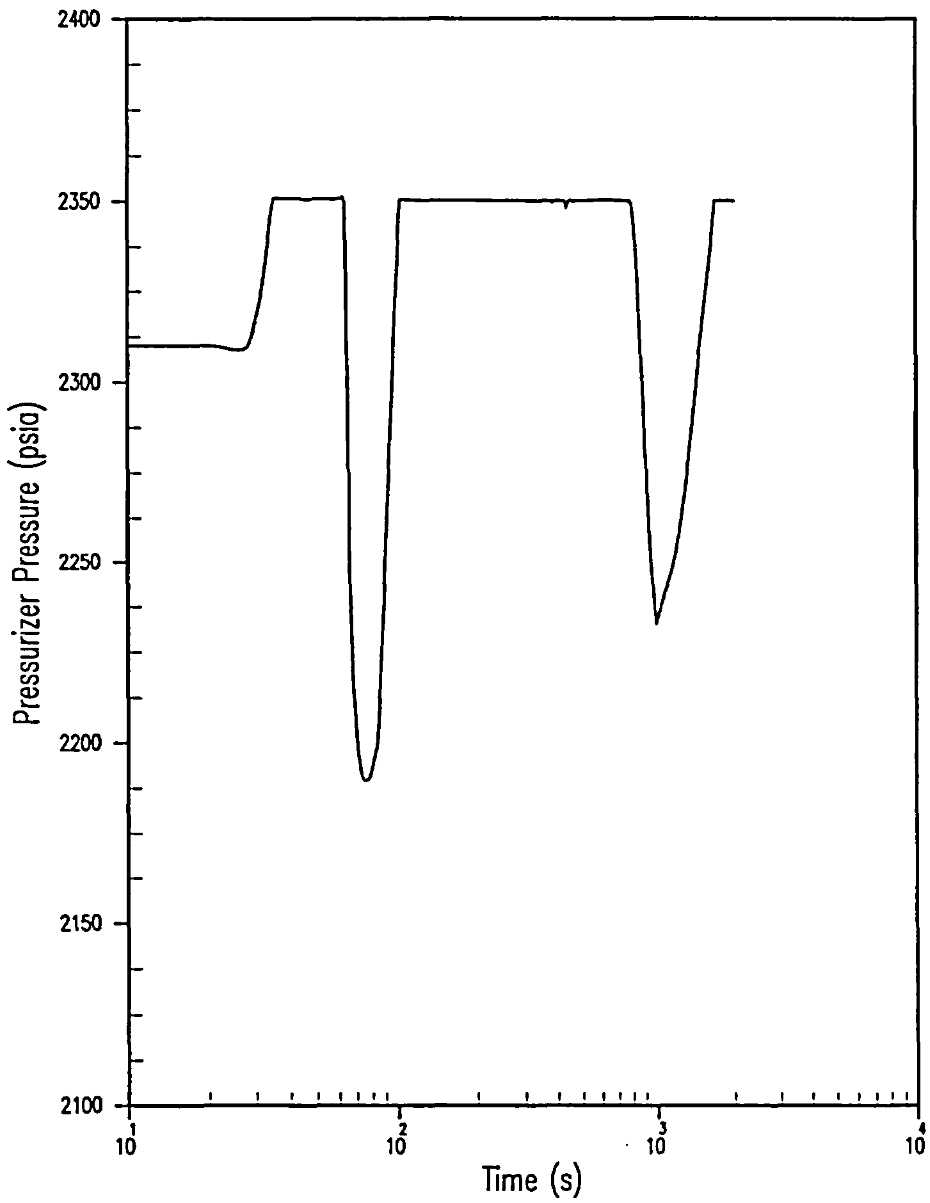


Figure 6.3-50

LOAC to the Plant Auxiliaries

(Pressurizer Pressure vs. Time)

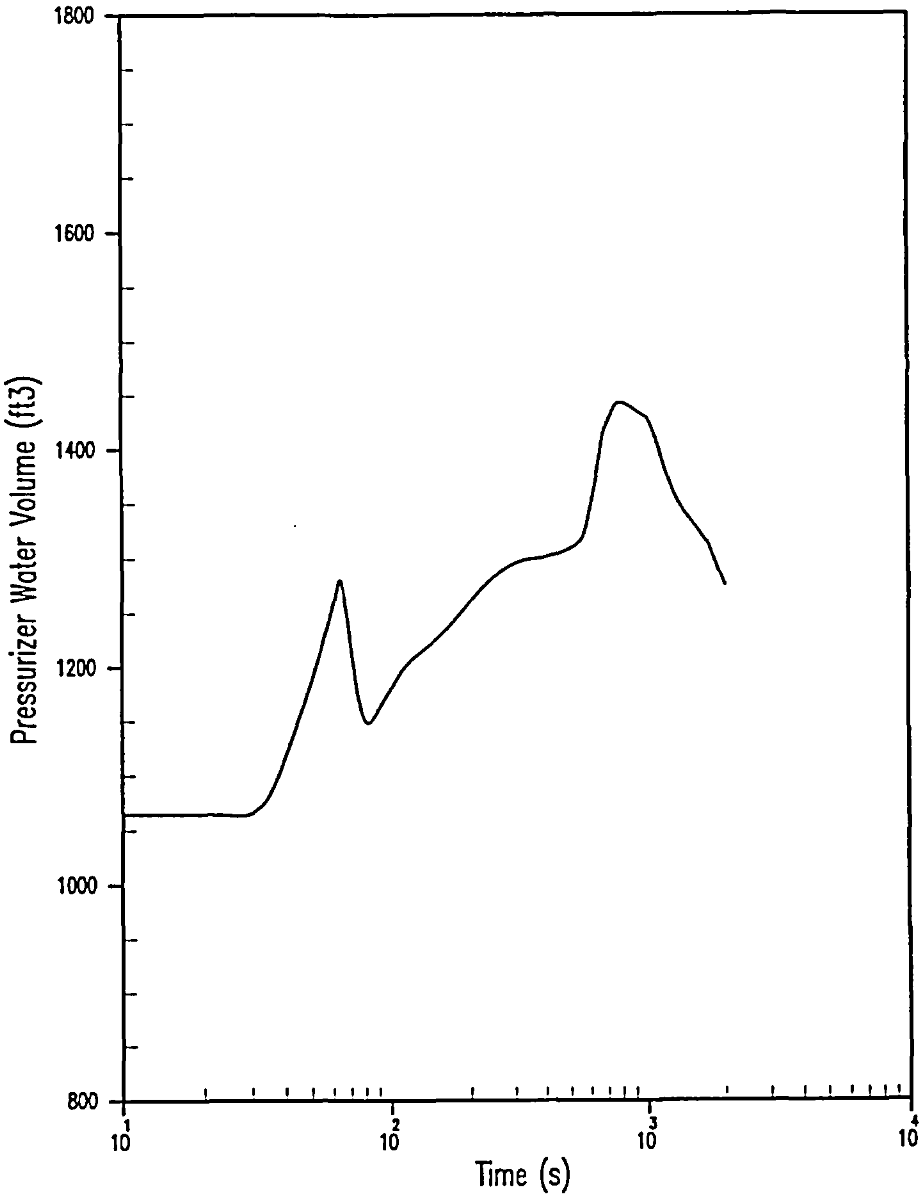


Figure 6.3-51

LOAC to the Plant Auxiliaries

(Pressurizer Water Volume vs. Time)

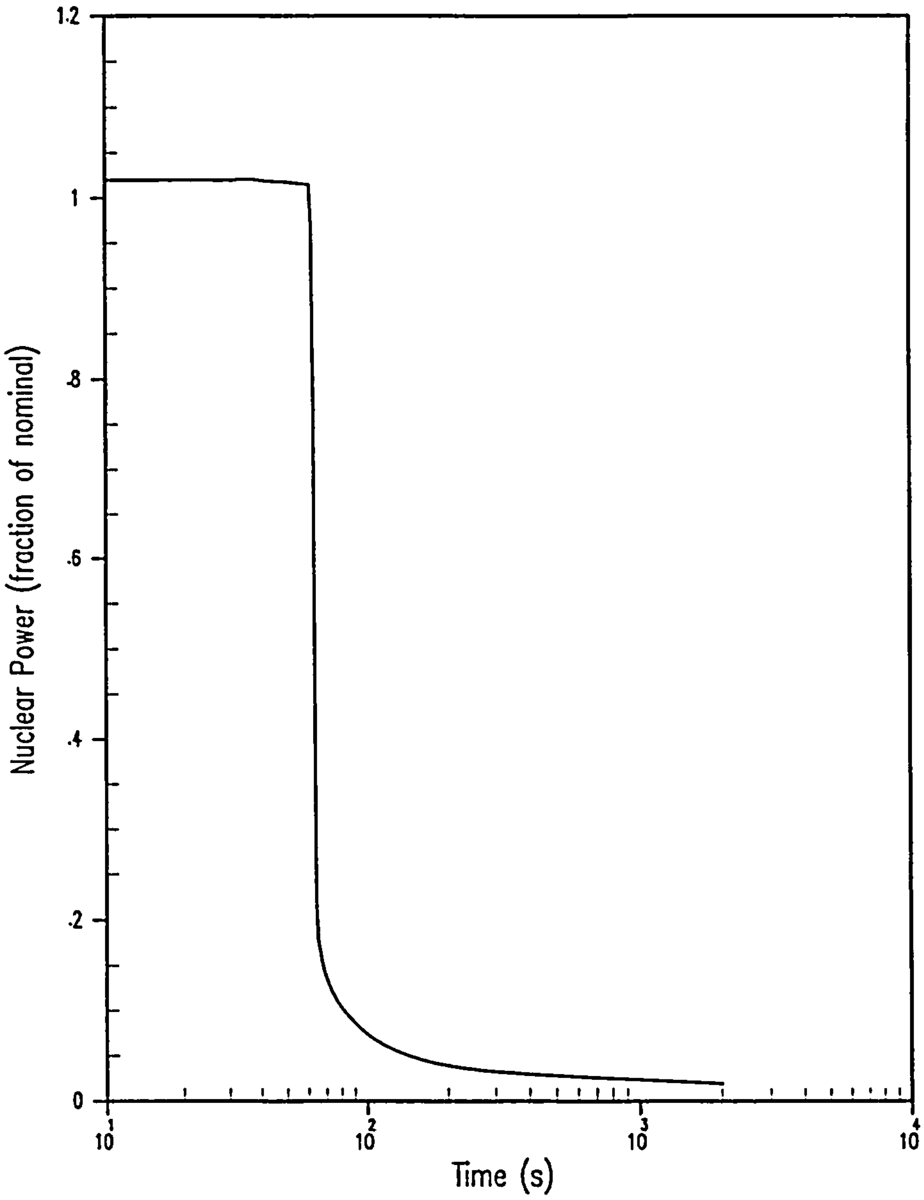


Figure 6.3-52

LOAC to the Plant Auxiliaries

(Nuclear Power vs. Time)

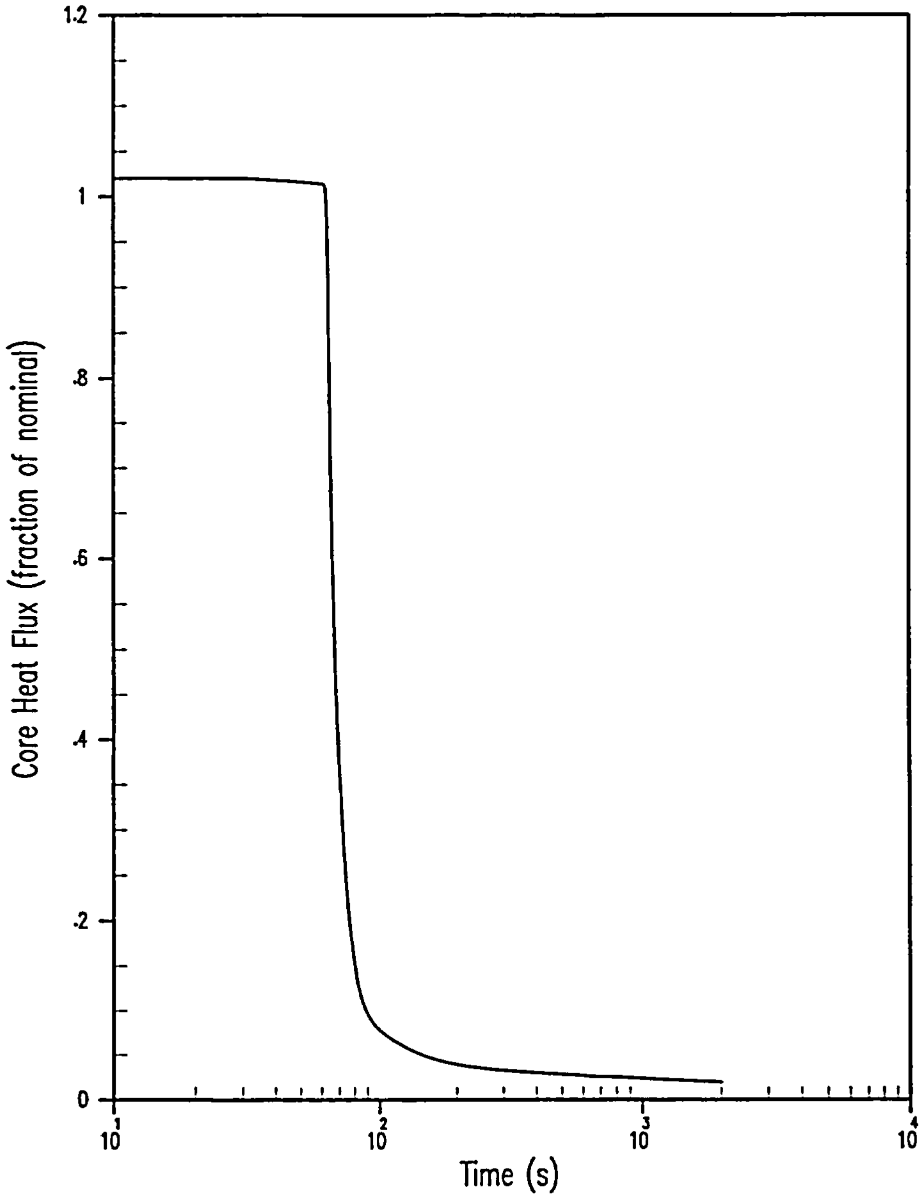


Figure 6.3-53

LOAC to the Plant Auxiliaries

(Core Heat Flux vs. Time)

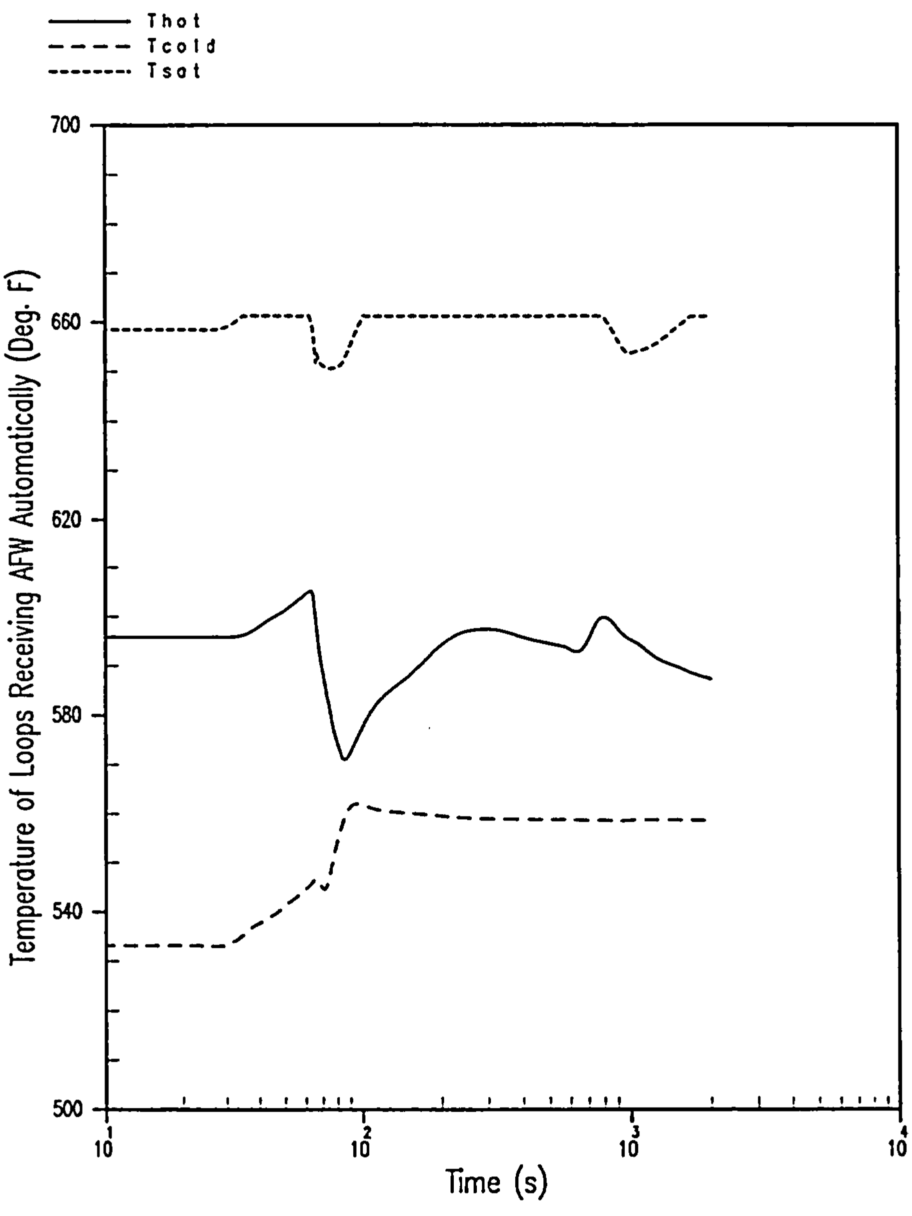


Figure 6.3-54

LOAC to the Plant Auxiliaries

(RCS Temperatures for Loops Receiving Automatic AFW Flow vs. Time)

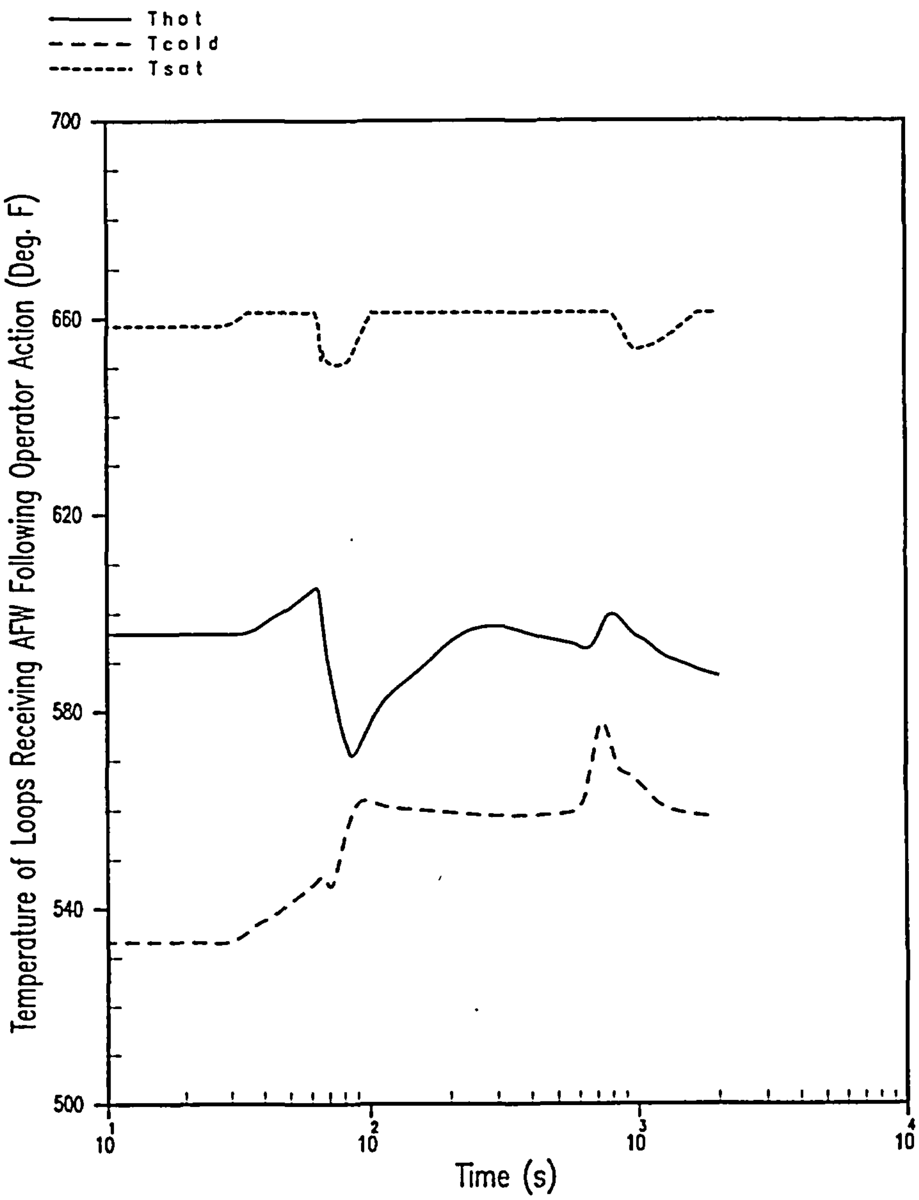


Figure 6.3-55

LOAC to the Plant Auxiliaries

(RCS Temperatures for Loops Receiving AFW Flow Following Operator Action vs. Time)

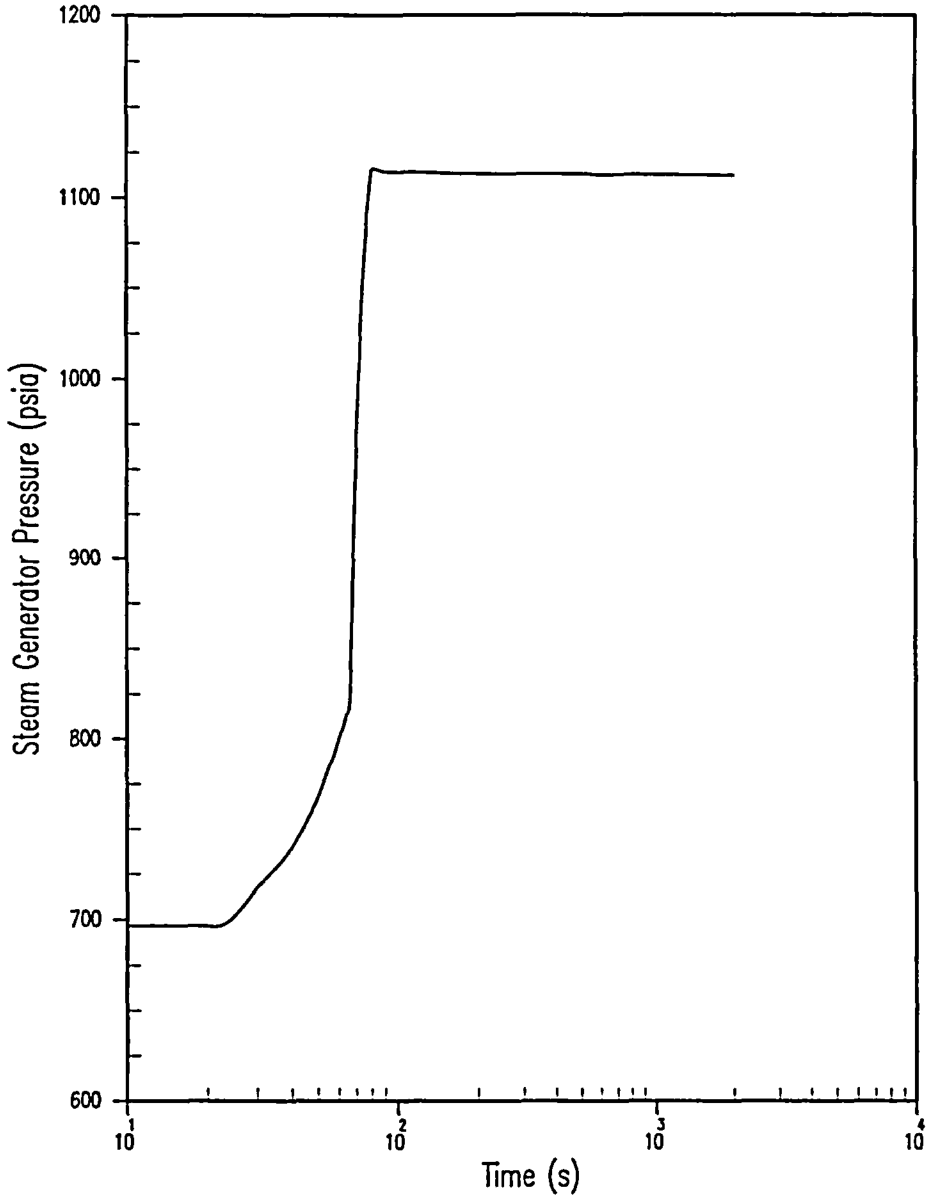


Figure 6.3-56

LOAC to the Plant Auxiliaries

(Steam Generator Pressure vs. Time)

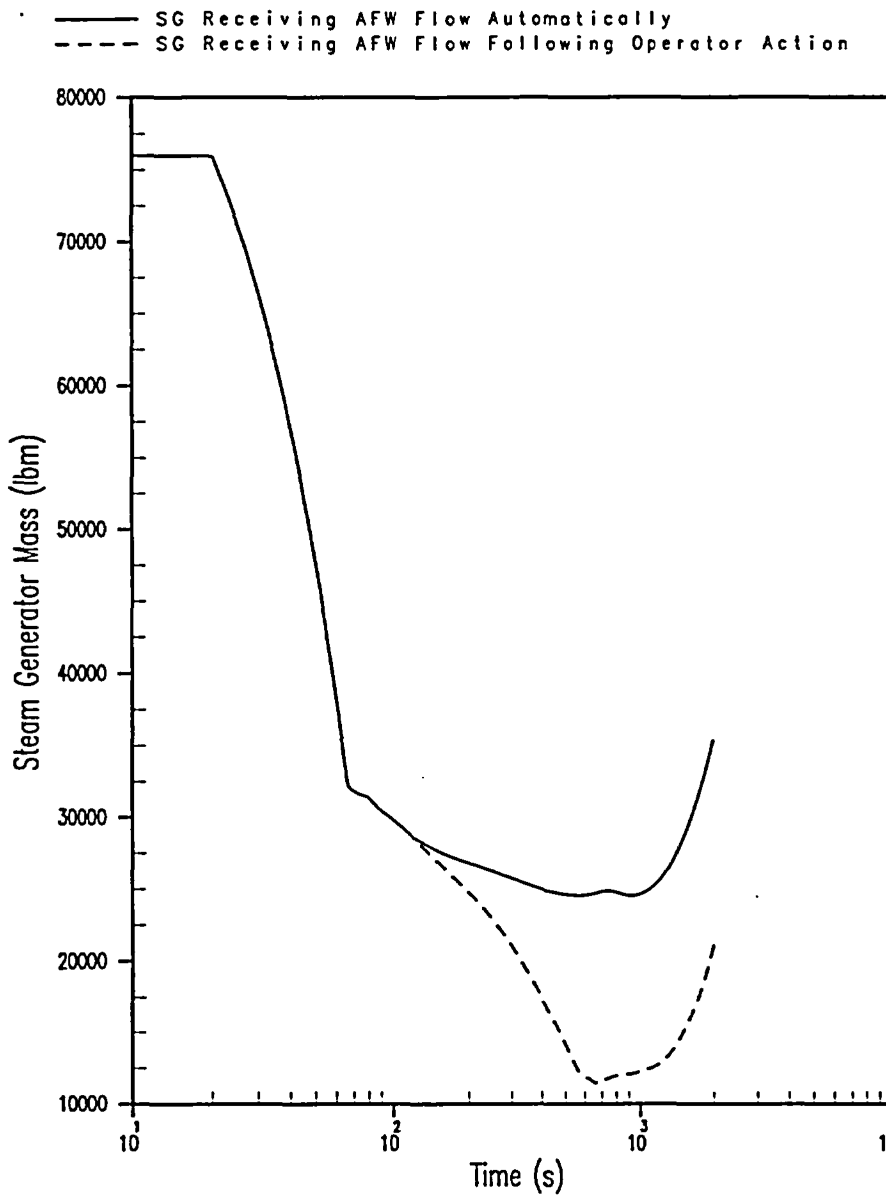


Figure 6.3-57

LOAC to the Plant Auxiliaries

(Steam Generator Mass vs. Time)

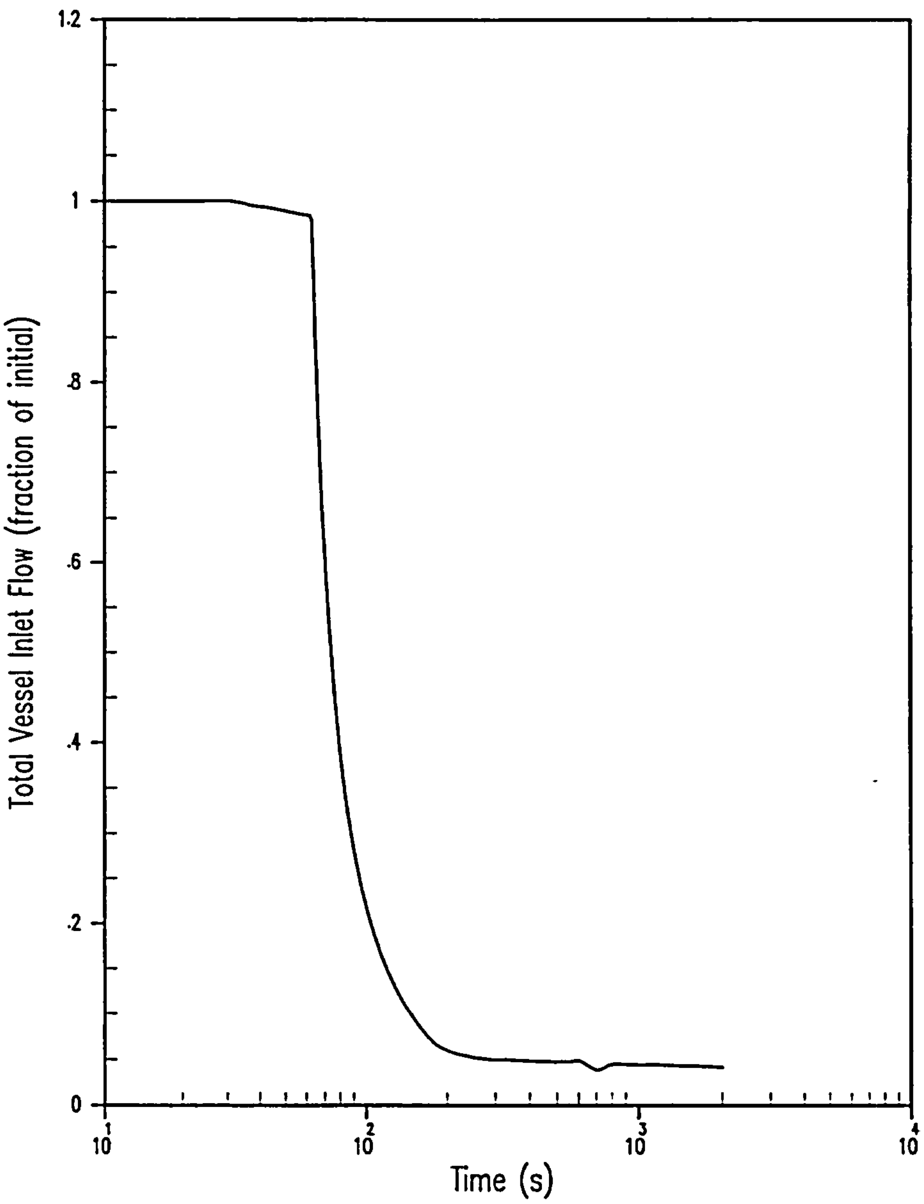
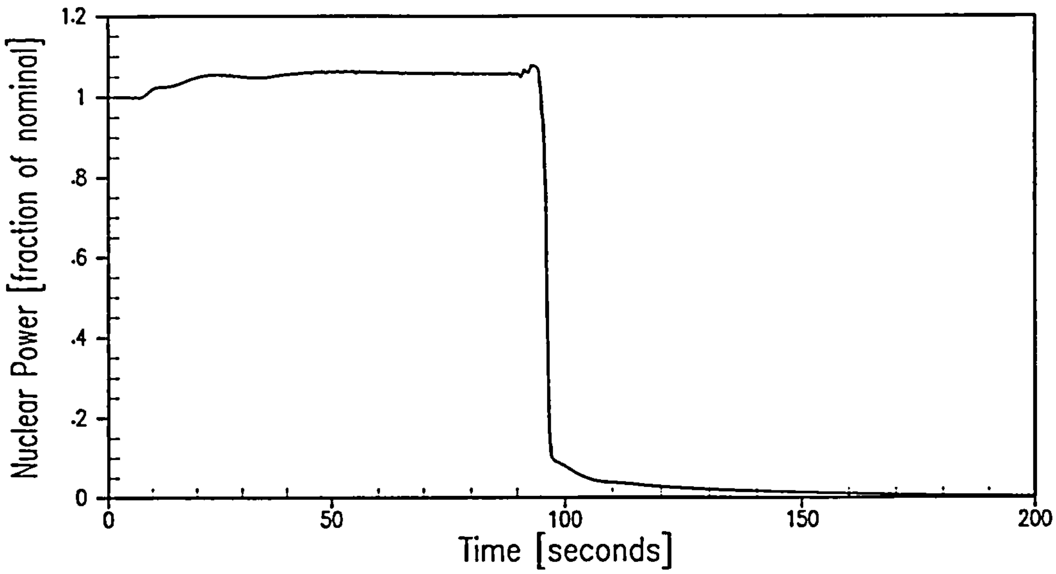


Figure 6.3-58

LOAC to the Plant Auxiliaries

(Total RCS Flow vs. Time)



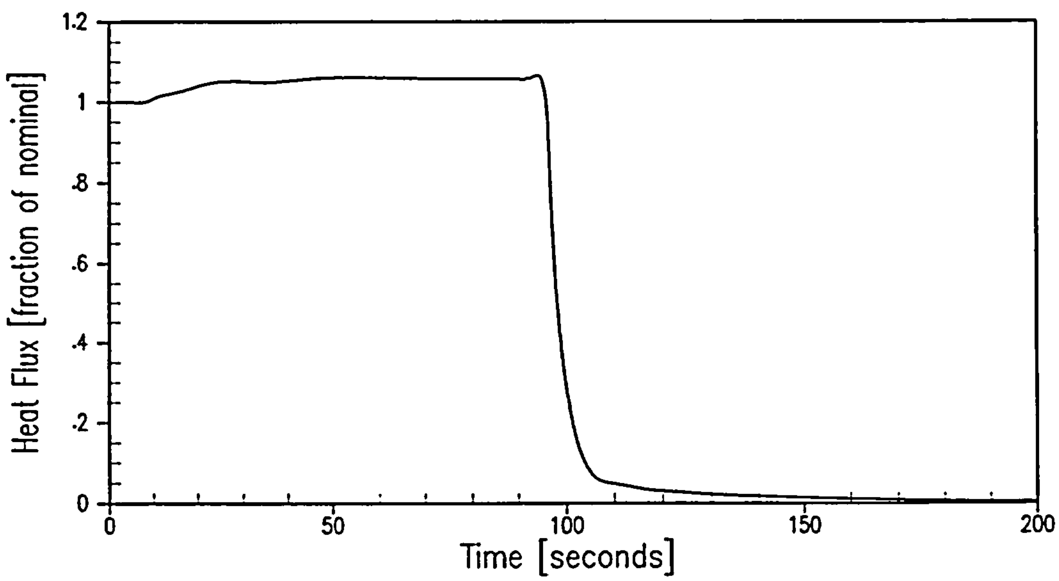


Figure 6.3-59

Feedwater System Malfunction at Full Power

(Nuclear Power and Core Heat Flux vs. Time)

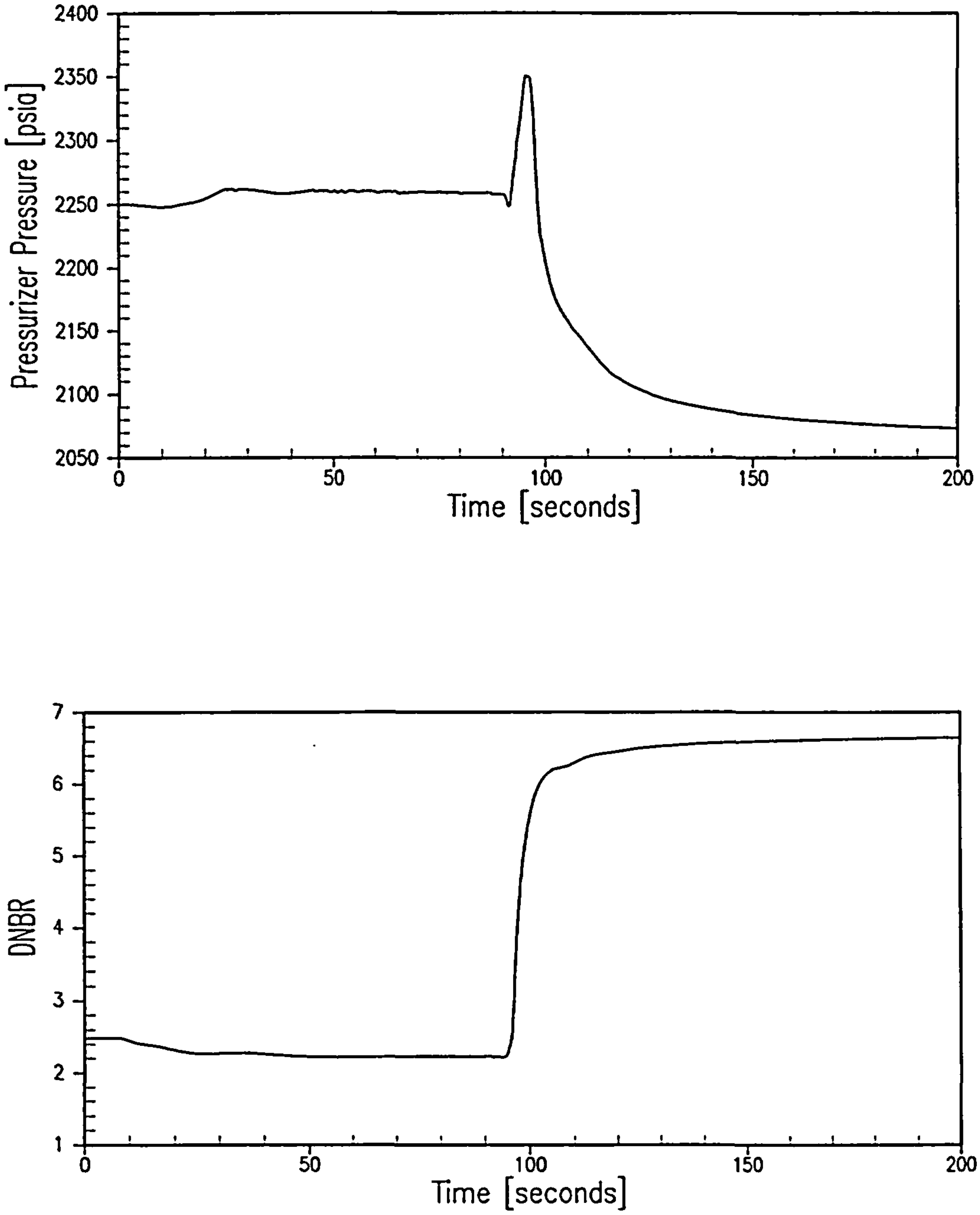
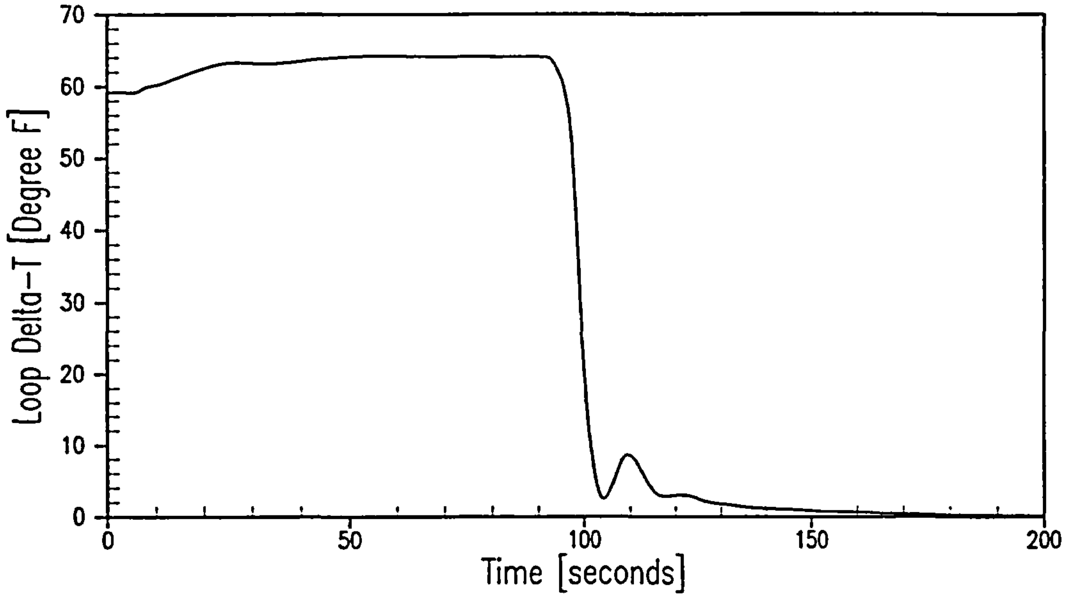


Figure 6.3-60

Feedwater System Malfunction at Full Power

(Pressurizer Pressure and DNBR vs. Time)



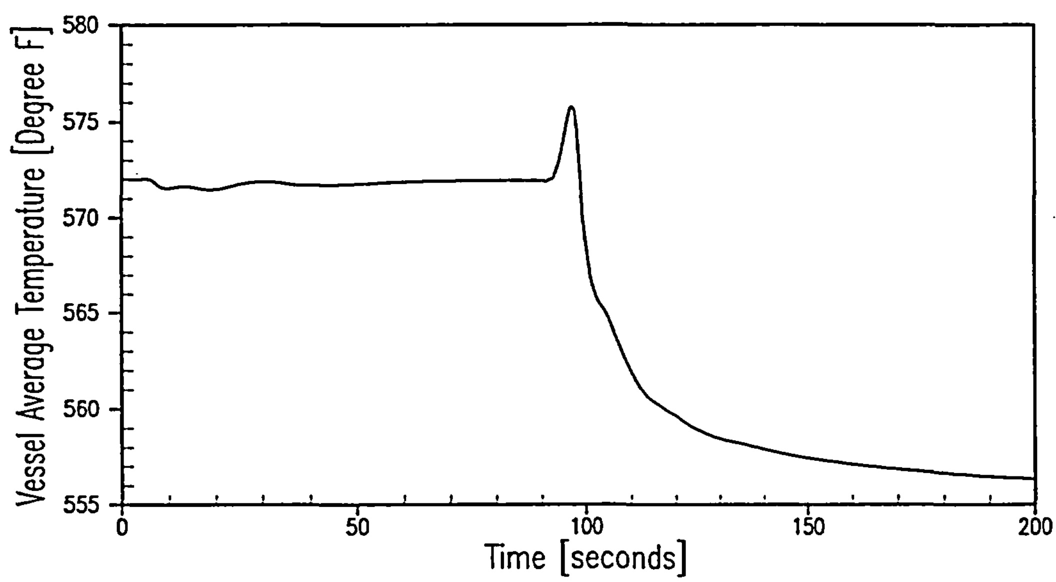


Figure 6.3-61

Feedwater System Malfunction at Full Power

(Loop Delta-T and Vessel Average Temperature vs. Time)

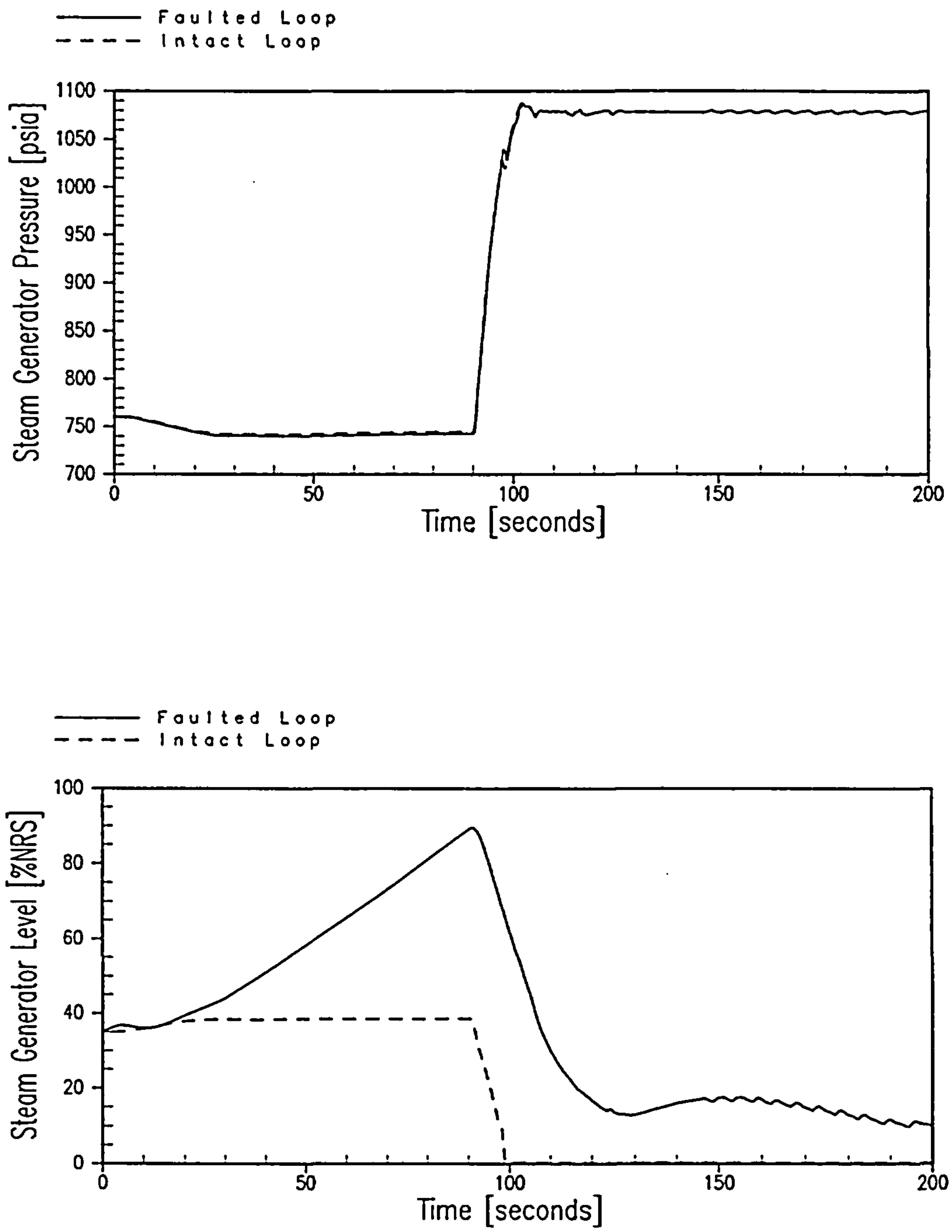


Figure 6.3-62

Feedwater System Malfunction at Full Power

(Steam Generator Pressure and Steam Generator Level vs. Time)

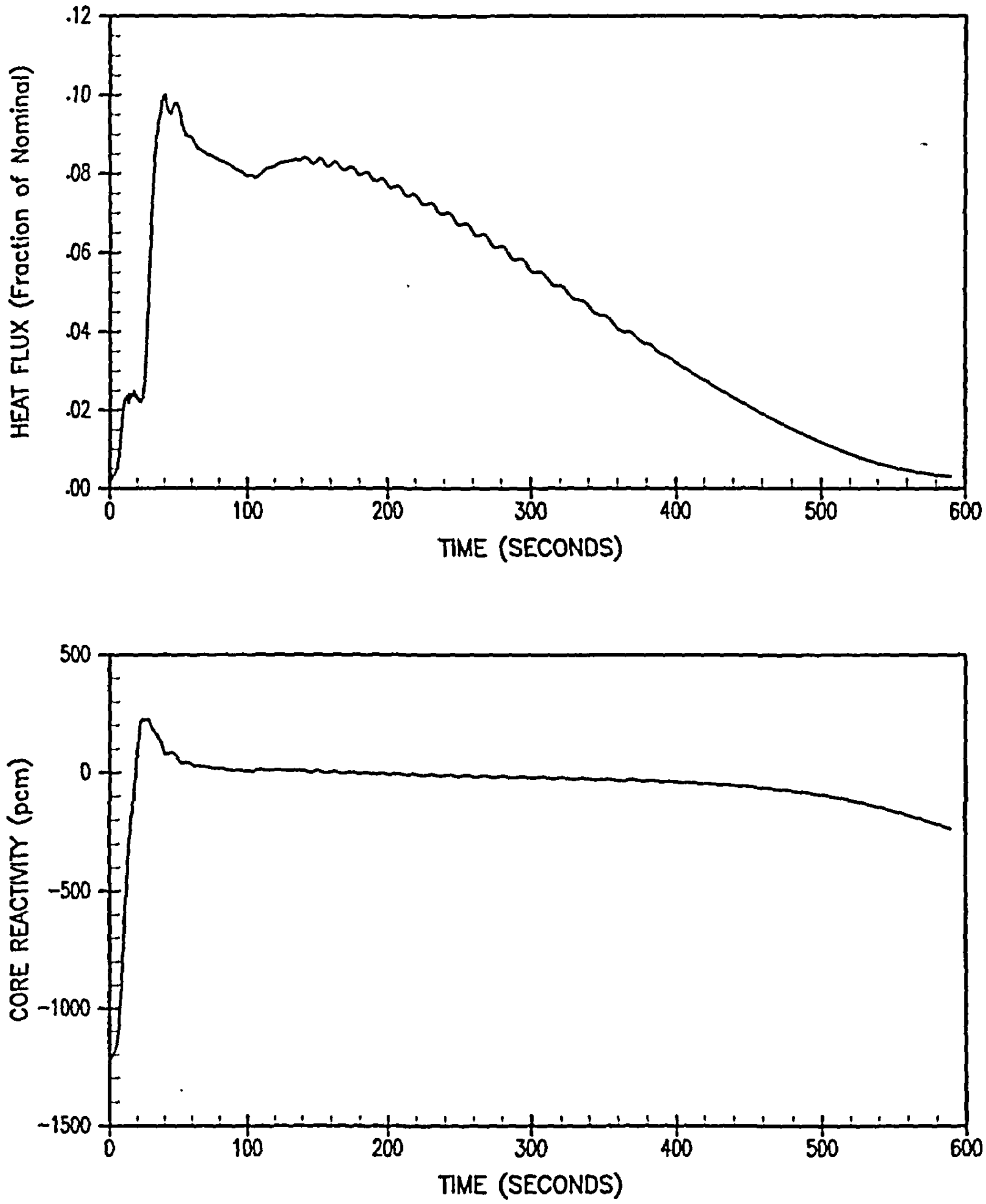


Figure 6.3-63

1.4 ft^2 Steamline Break, Offsite Power Available

(Core Heat Flux and Core Reactivity vs. Time)

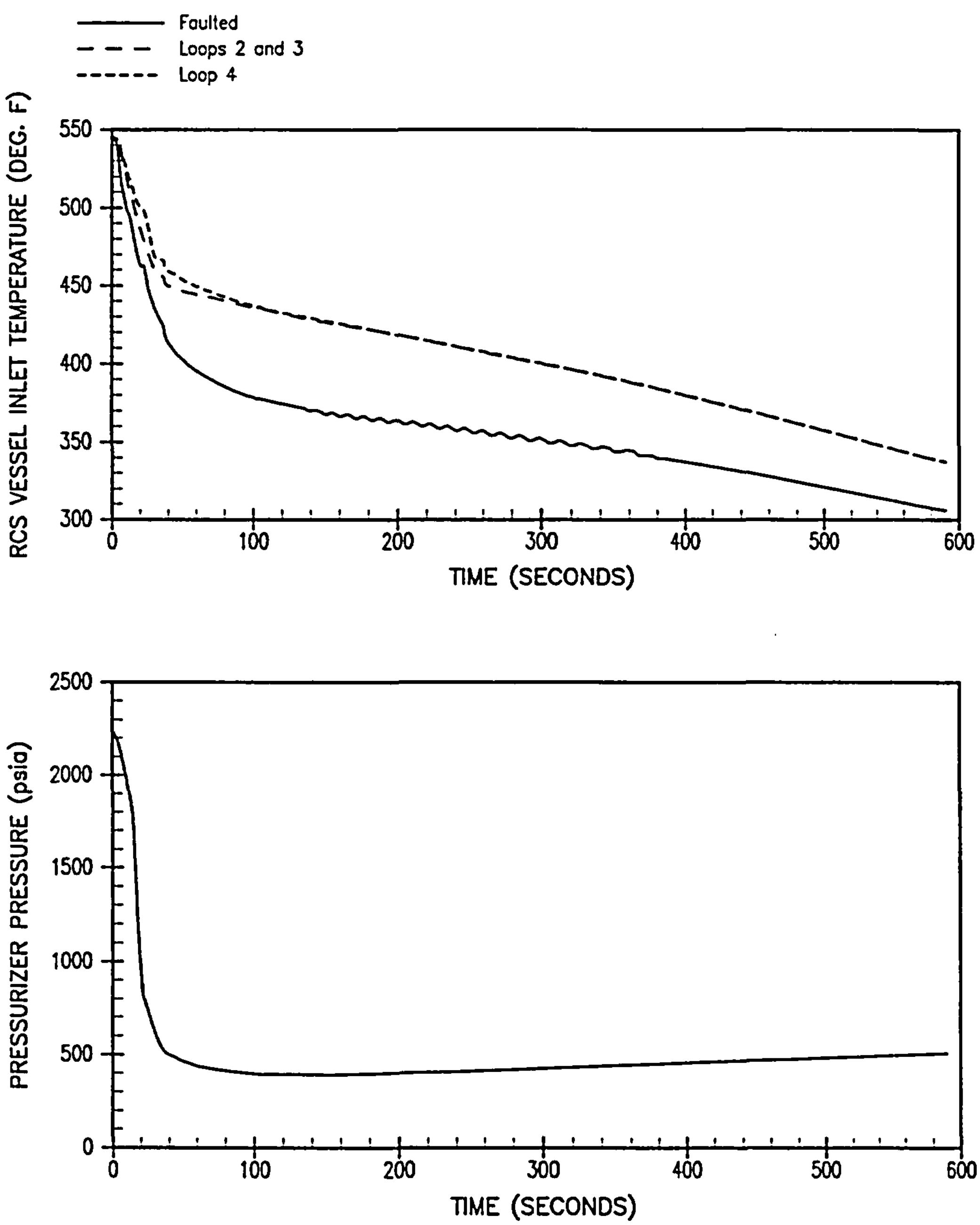
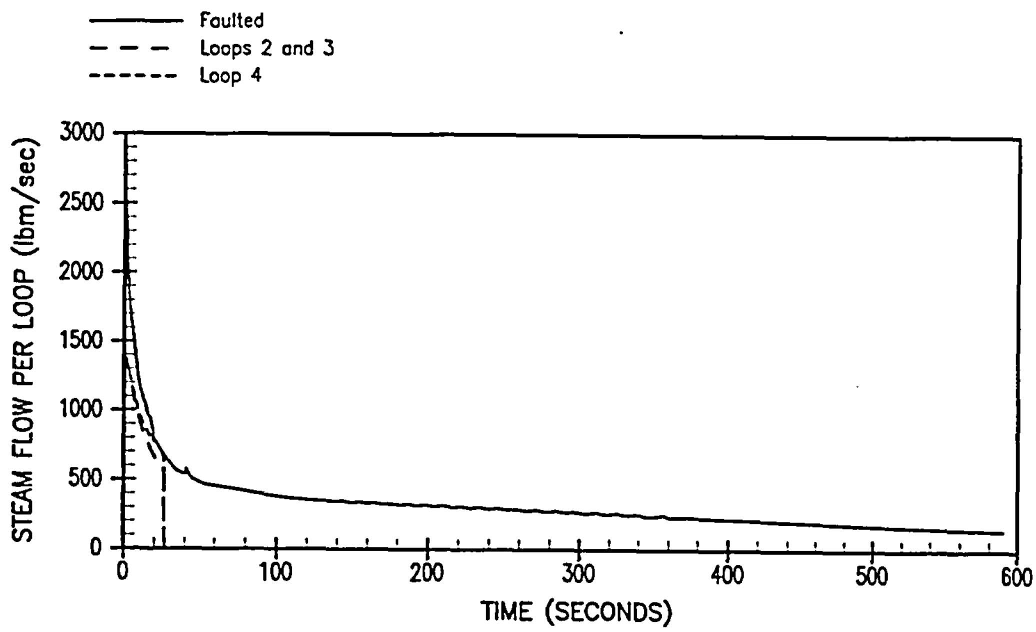


Figure 6.3-64

1.4 ft^2 Steamline Break, Offsite Power Available

(Reactor Vessel Inlet Temperature and Pressurizer Pressure vs. Time)



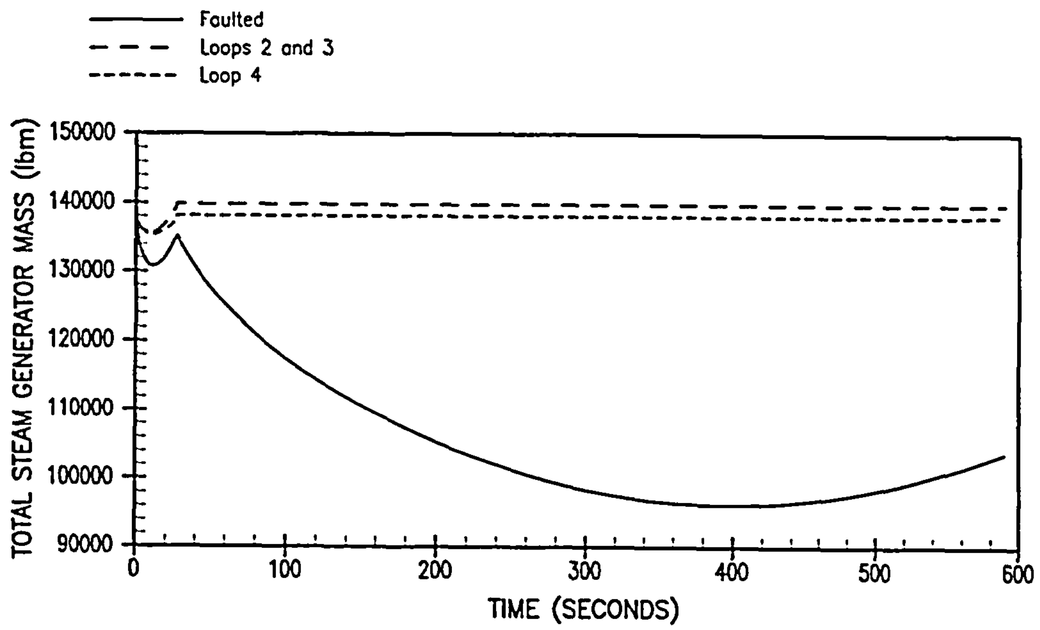


Figure 6.3-65

1.4 ft^2 Steamline Break, Offsite Power Available

(Steam Flow and Steam Generator Mass vs. Time)

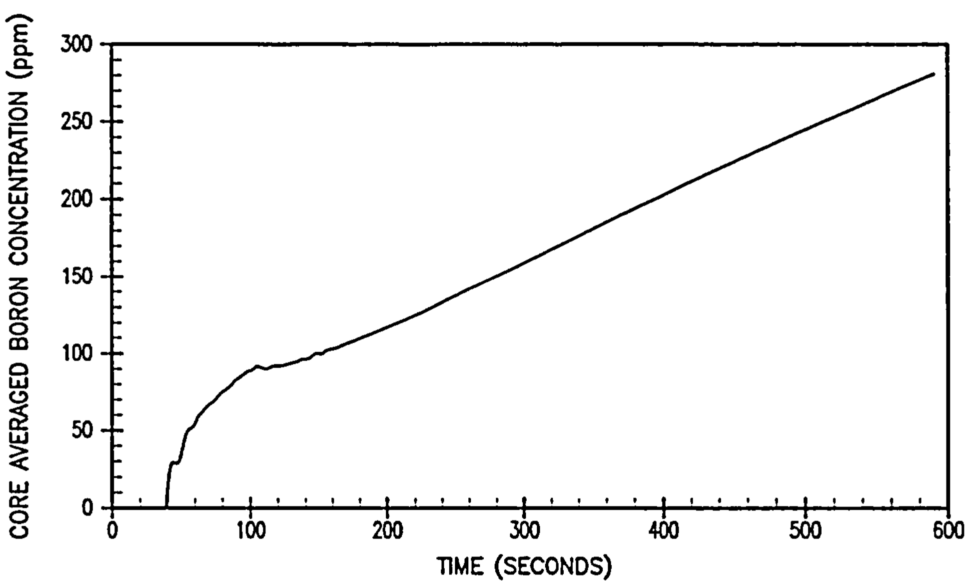


Figure 6.3-66

1.4 ft^2 Steamline Break, Offsite Power Available

(Core Averaged Boron Concentration vs. Time)

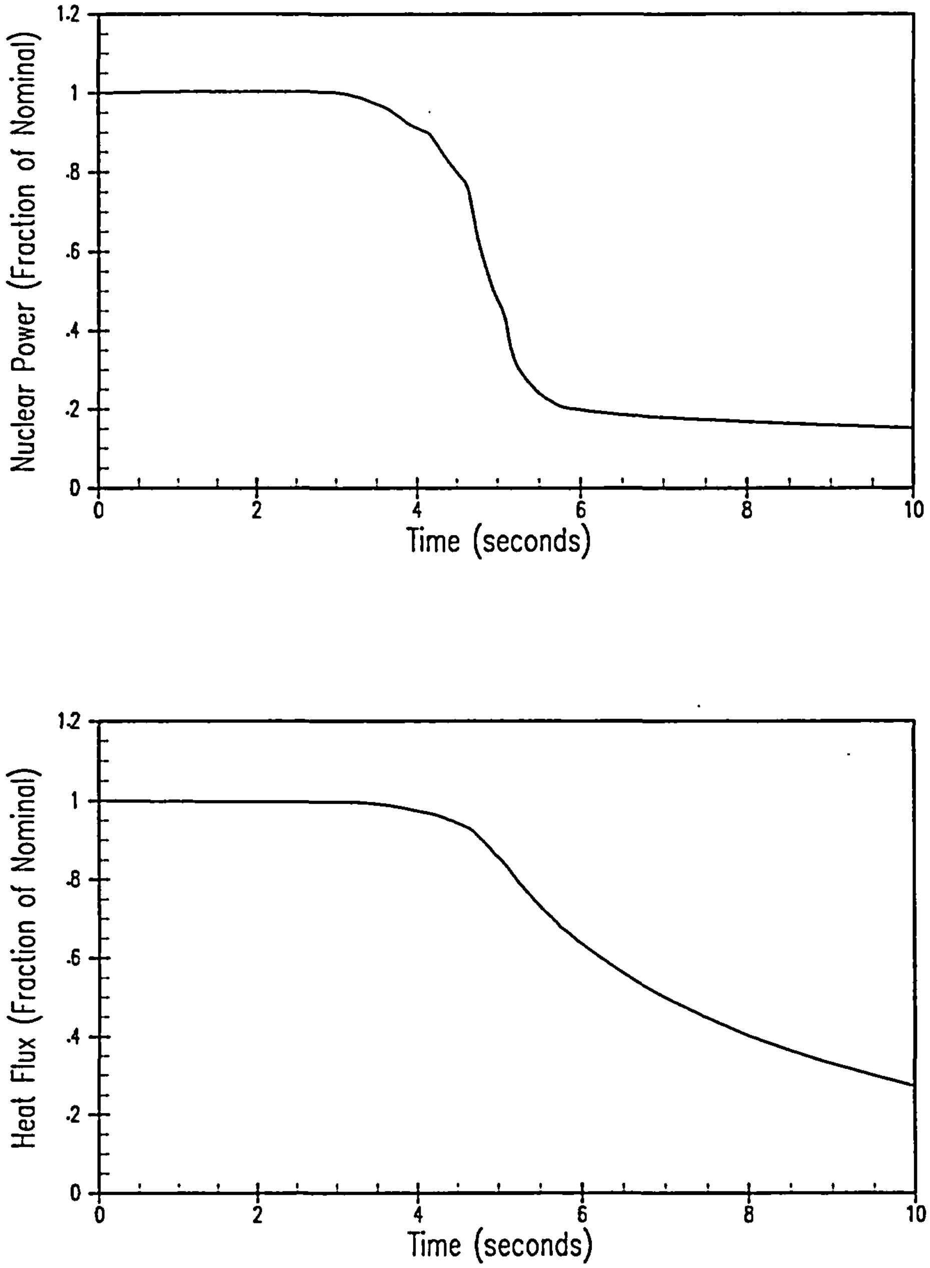


Figure 6.3-67

Partial Loss of Forced Reactor Coolant Flow

(Nuclear Power and Heat Flux vs. Time)

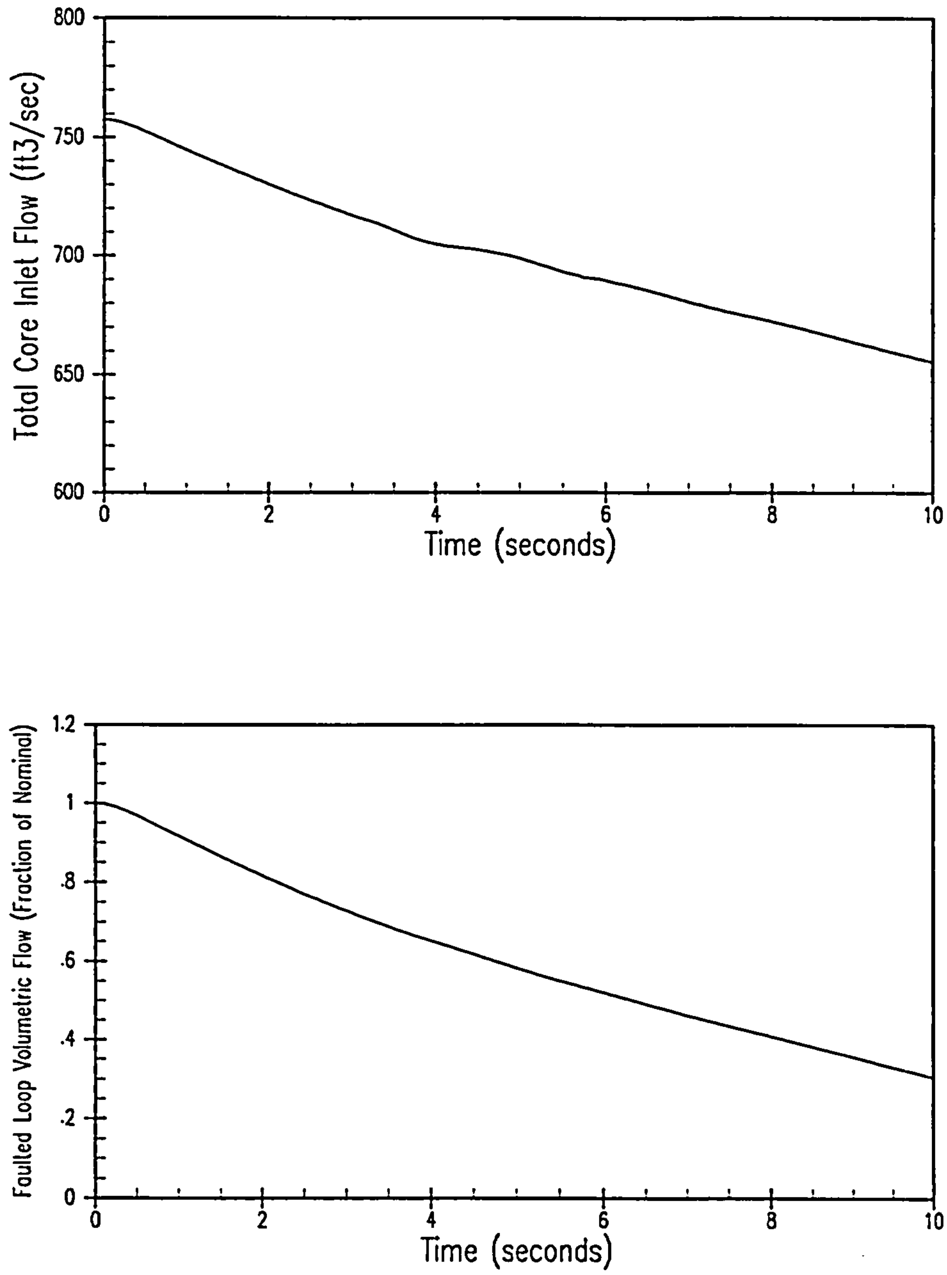
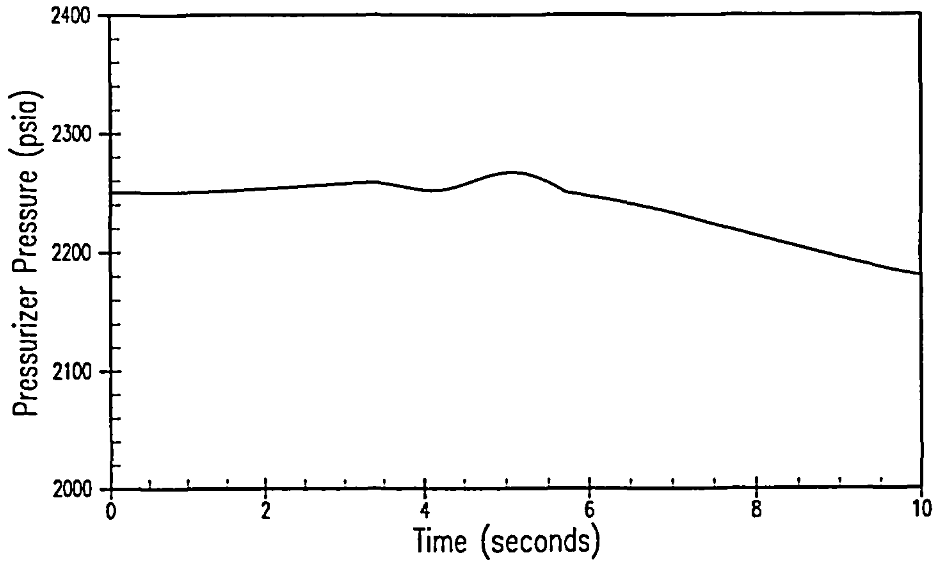


Figure 6.3-68

Partial Loss of Forced Reactor Coolant Flow

(Total Core Flow and Faulted Loop Flow vs. Time)



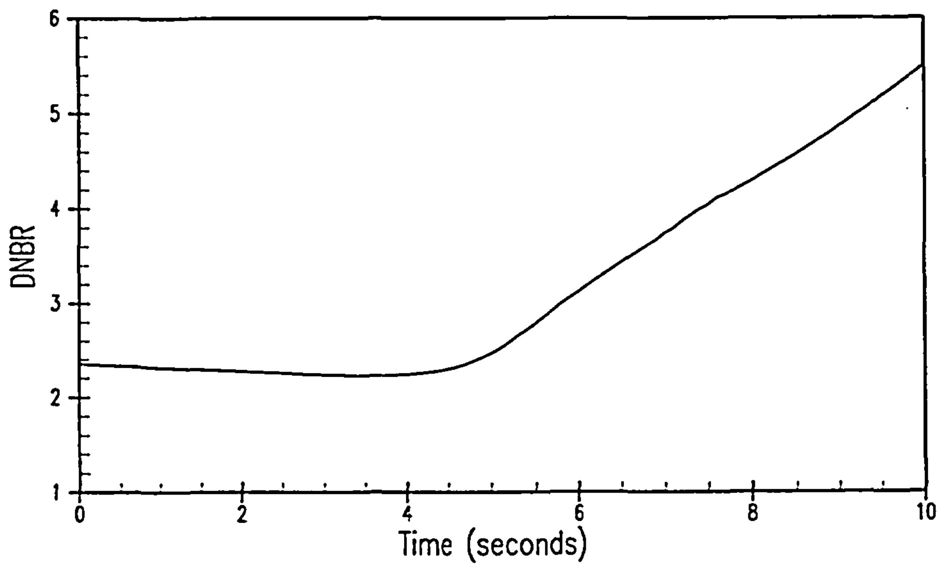


Figure 6.3-69

Partial Loss of Forced Reactor Coolant Flow

(Pressurizer Pressure and DNBR vs. Time)

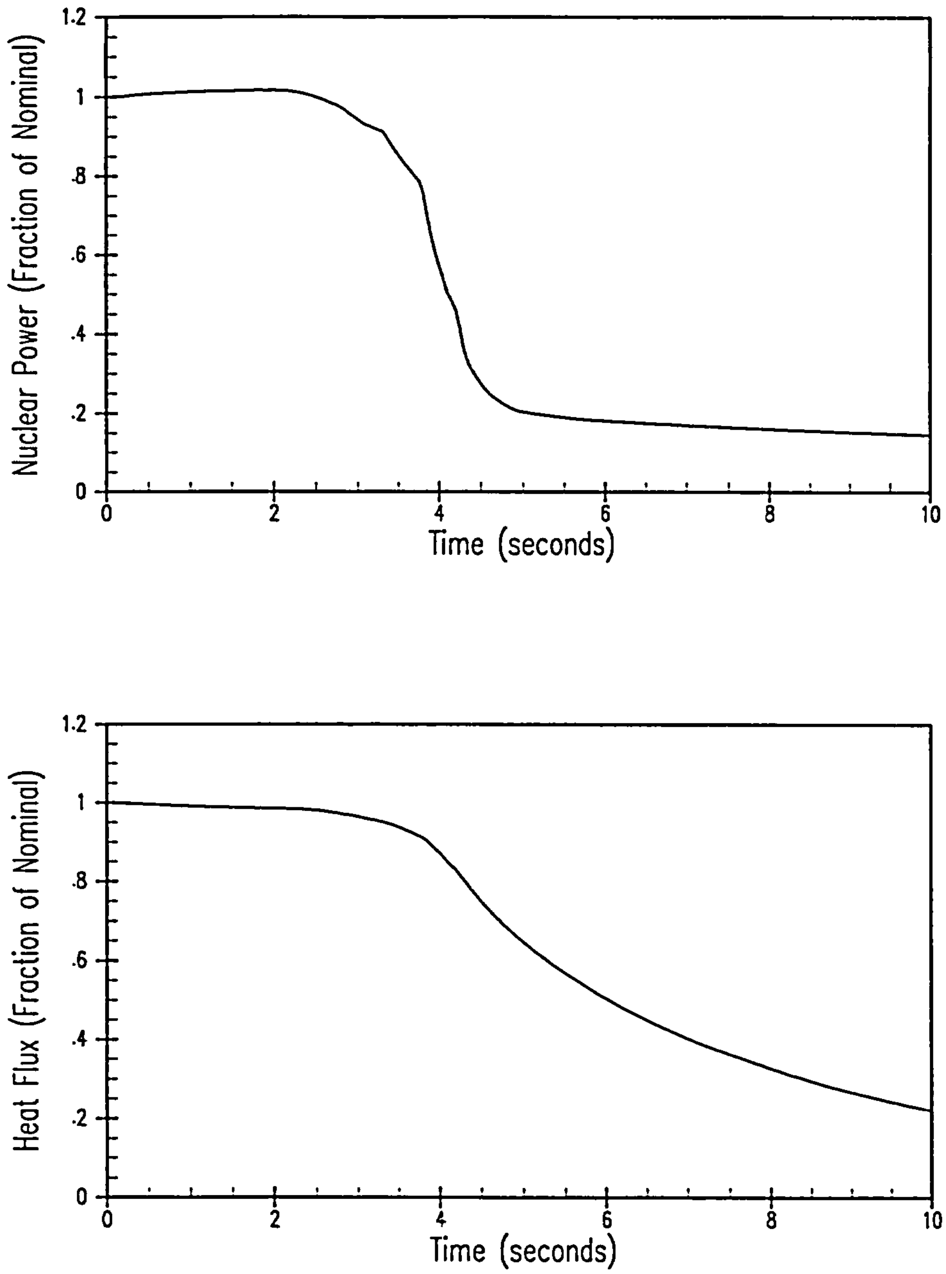


Figure 6.3-70

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Nuclear Power and Heat Flux vs. Time)

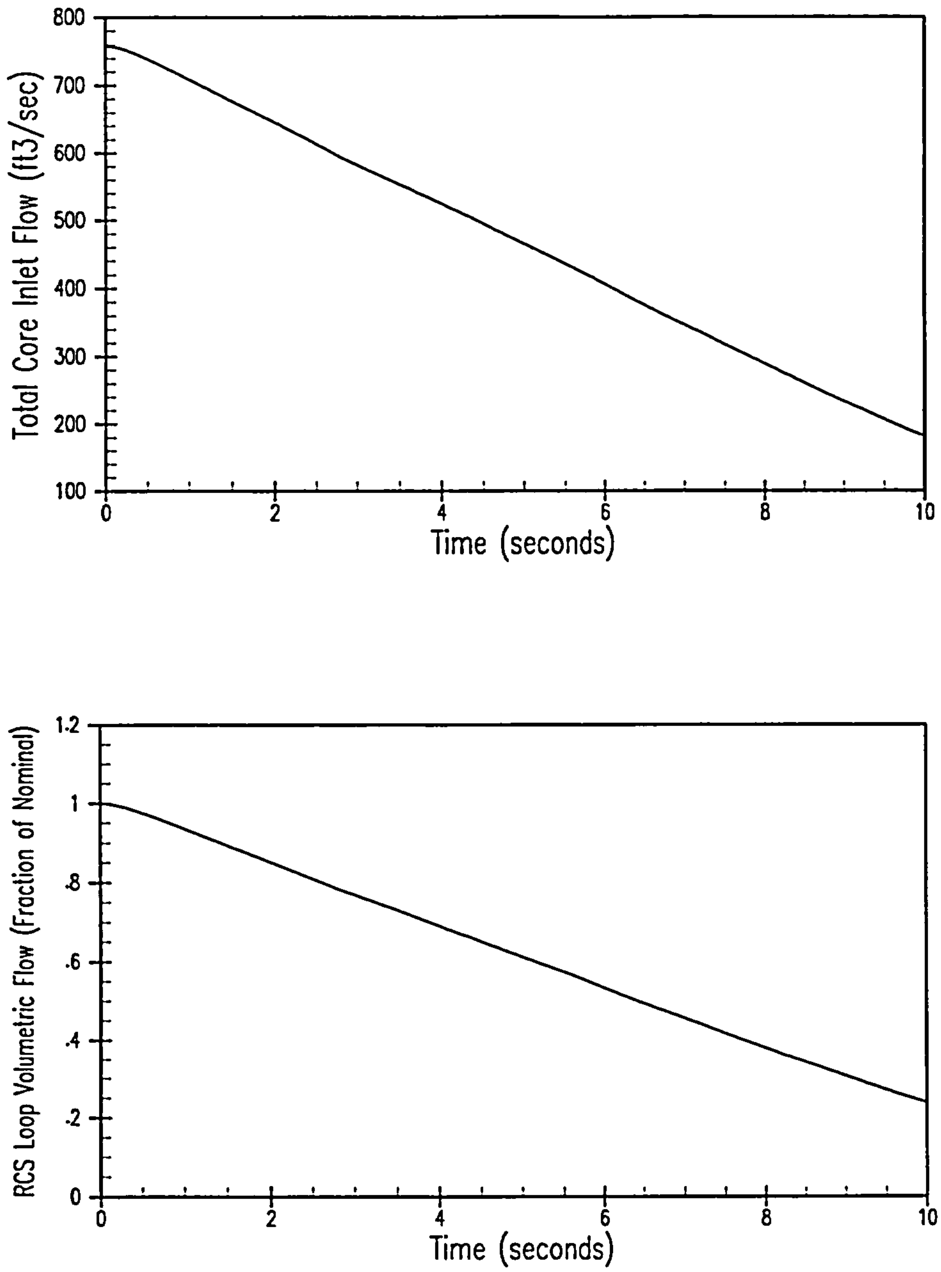


Figure 6.3-71

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Total Core Flow and RCS Loop Flow vs. Time)

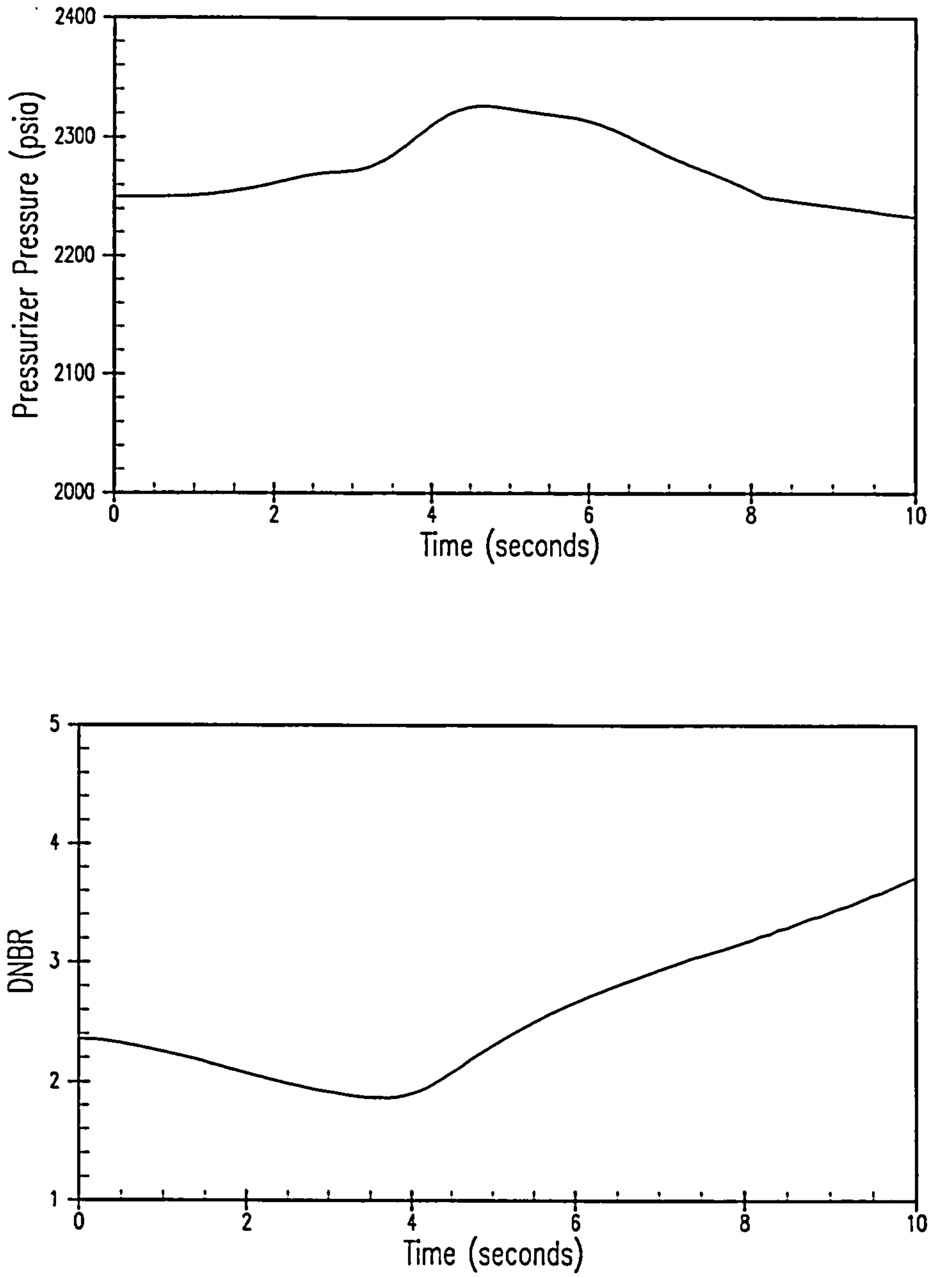
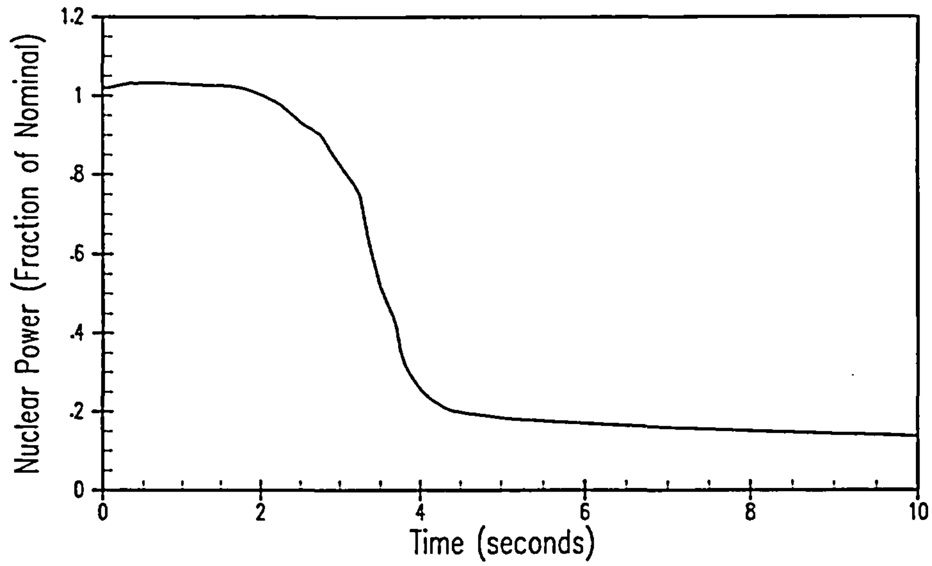


Figure 6.3-72

Complete Loss of Forced Reactor Coolant Flow – Frequency Decay

(Pressurizer Pressure and DNBR vs. Time)



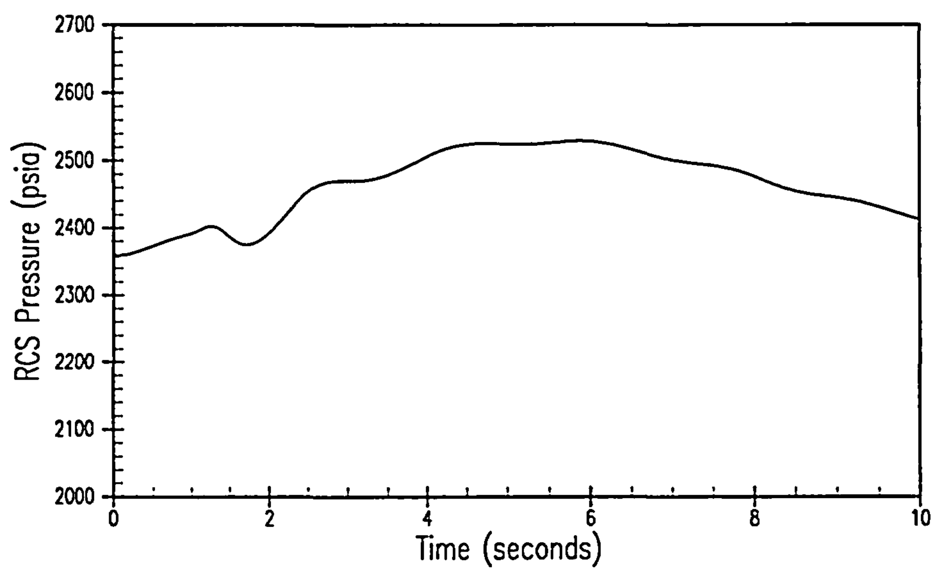


Figure 6.3-73

Locked Rotor/Shaft Break

(Nuclear Power and RCS Pressure vs. Time)

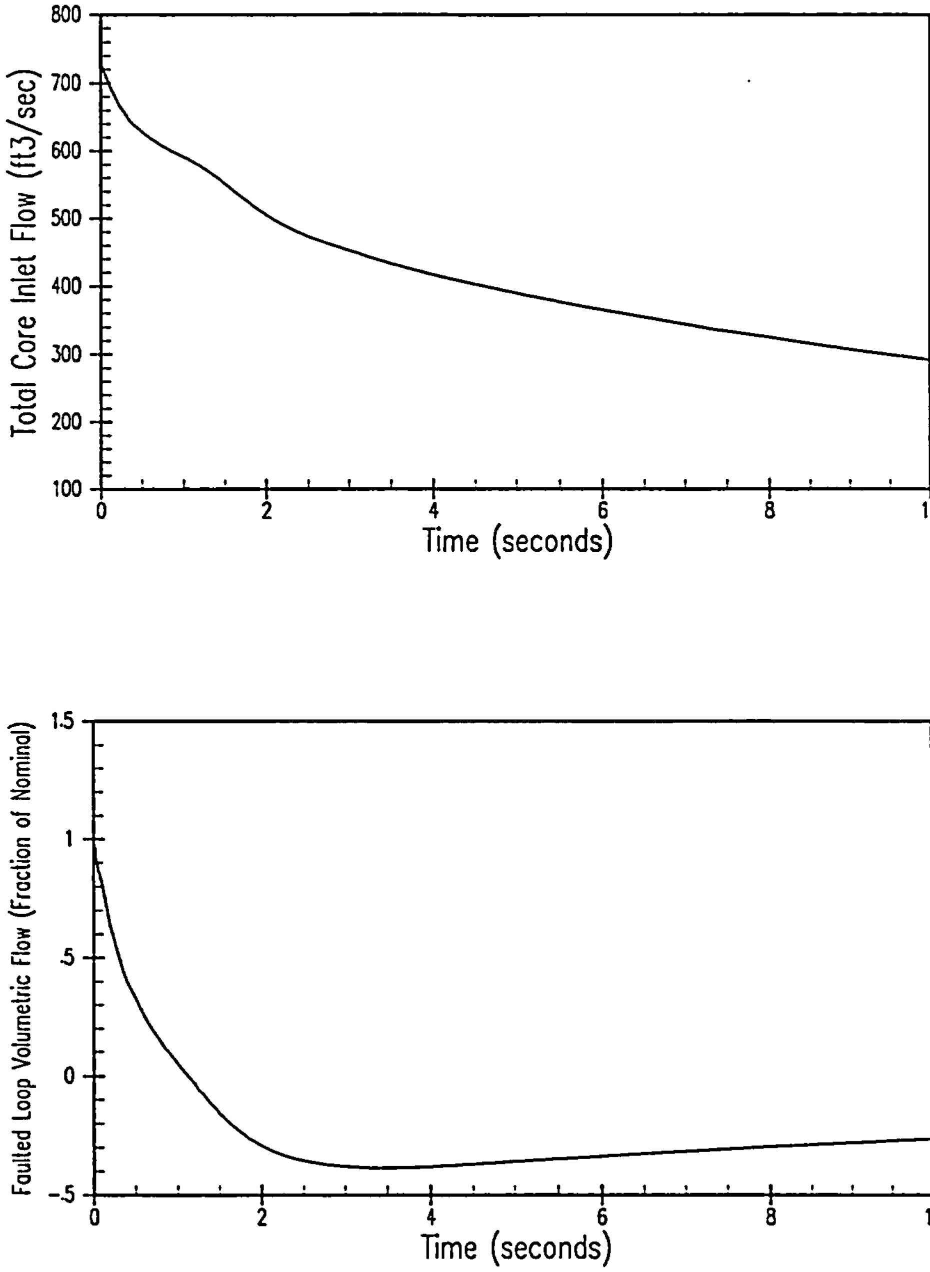


Figure 6.3-74

Locked Rotor/Shaft Break

(Total Core Flow and Faulted Loop Flow vs. Time)

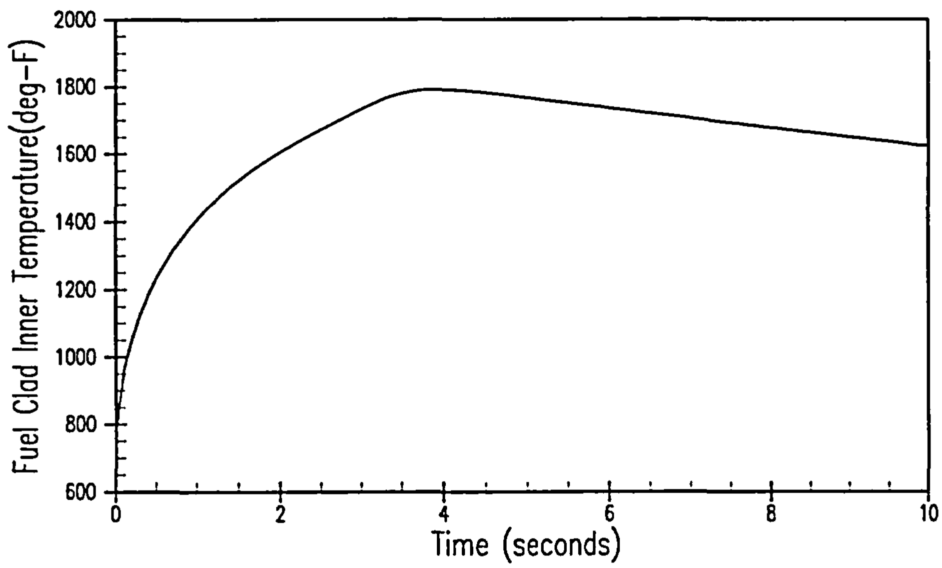


Figure 6.3-75

Locked Rotor/Shaft Break

(Fuel Clad Inner Temperature vs. Time)

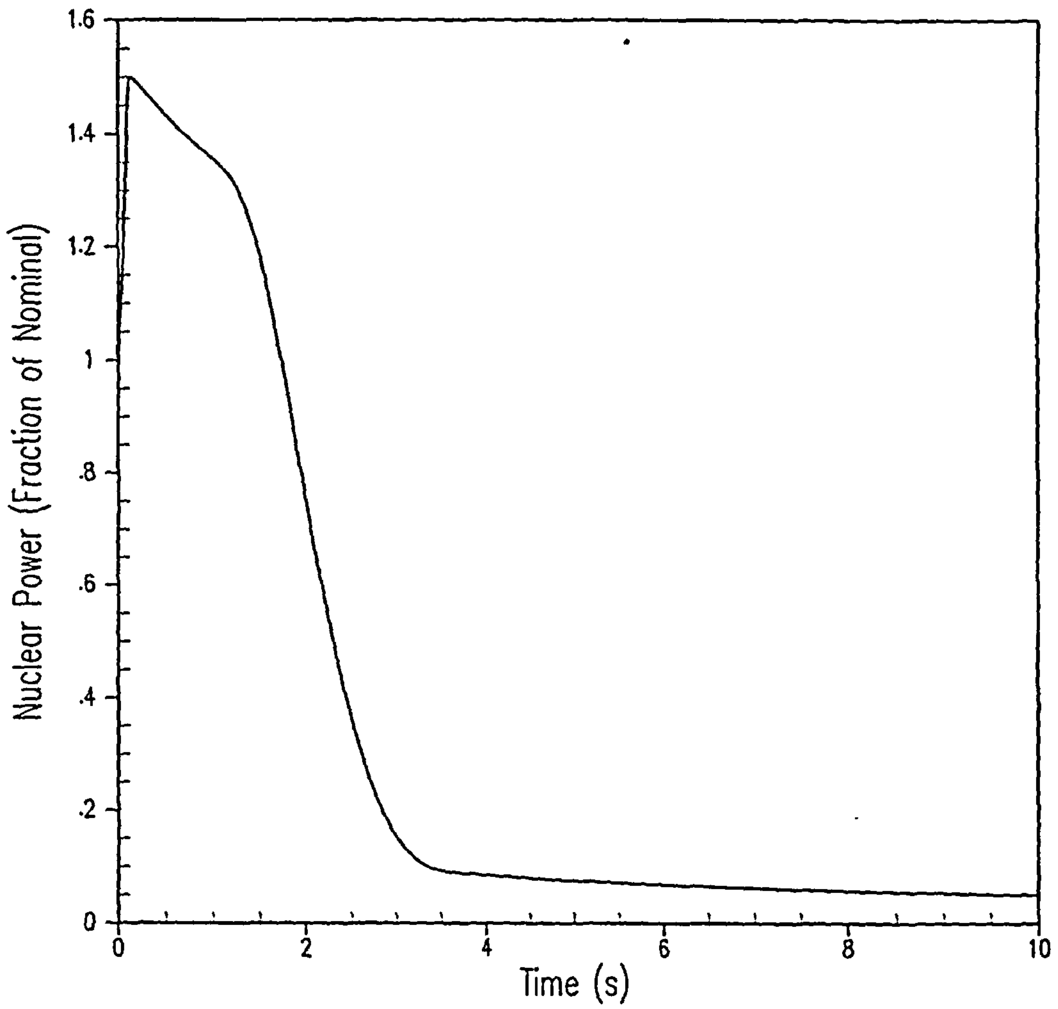


Figure 6.3-76

BOL HFP RCCA Ejection (Nuclear Power vs. Time)

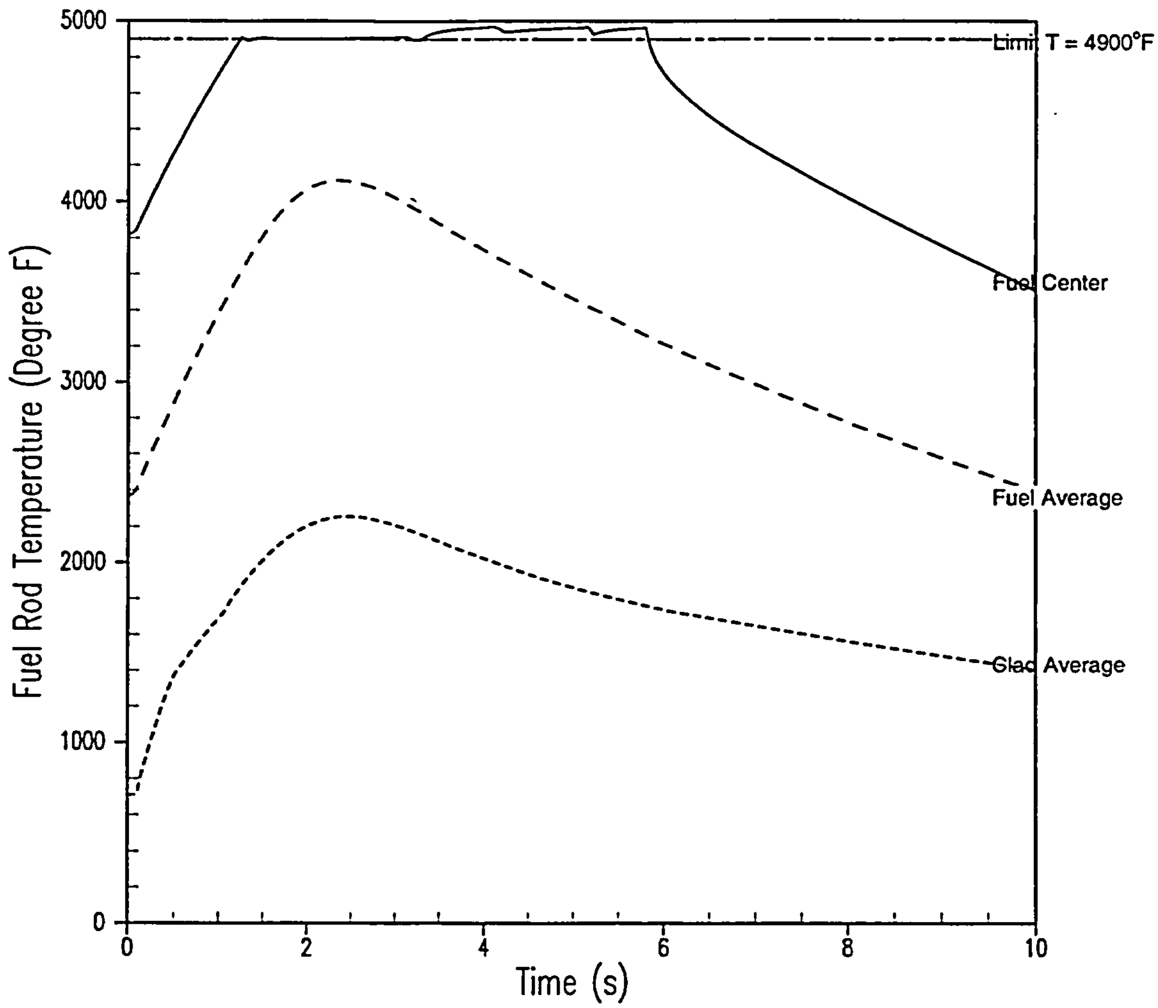


Figure 6.3-77

BOL HFP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

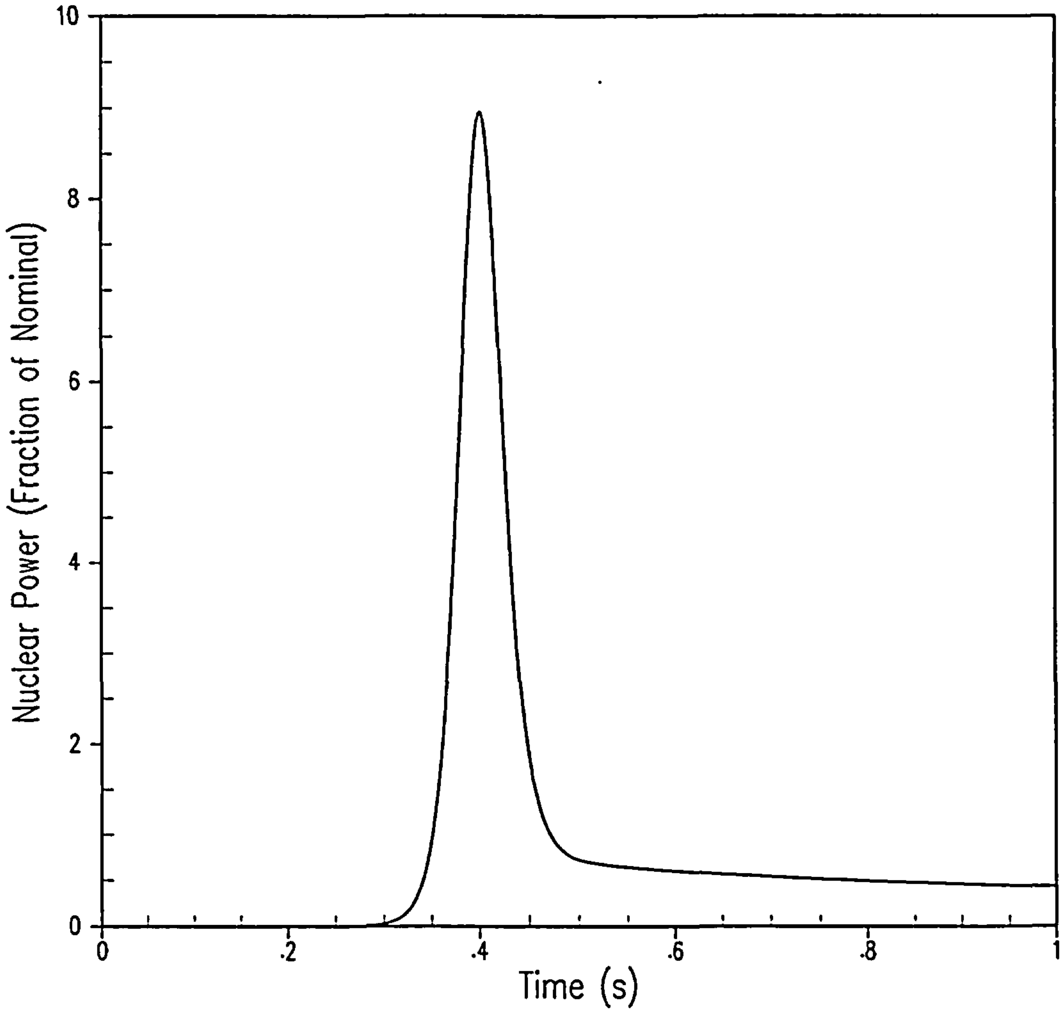


Figure 6.3-78
BOL HZP RCCA Ejection (Nuclear Power vs. Time)

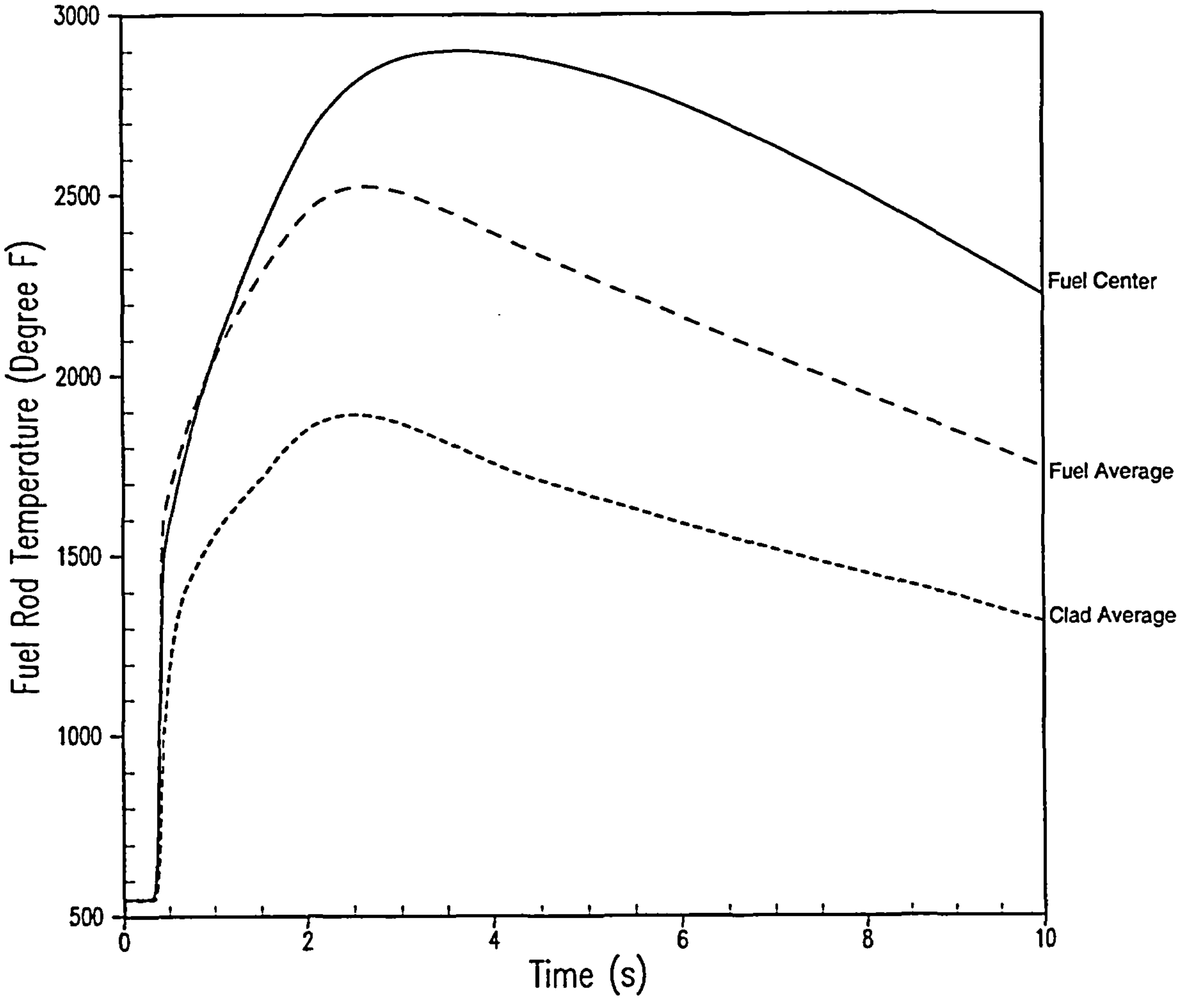


Figure 6.3-79

BOL HZP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

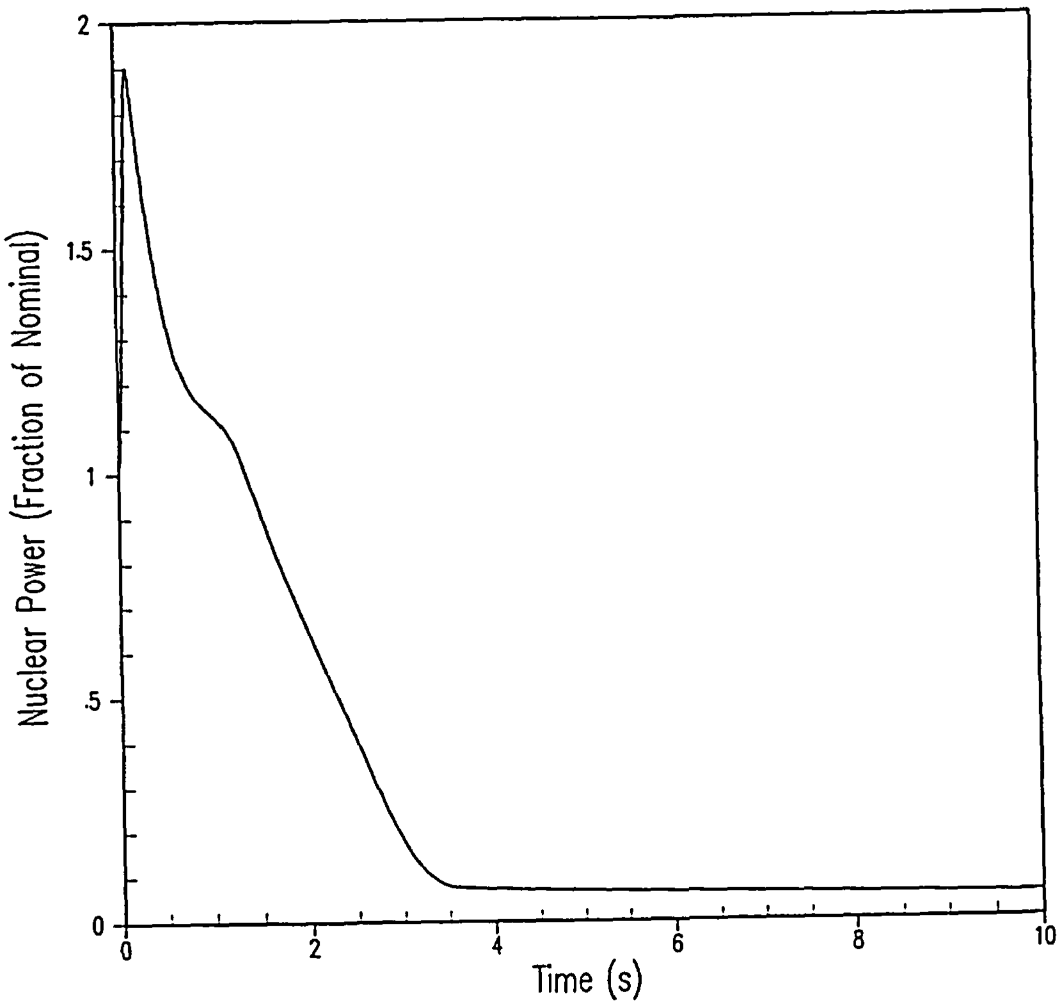


Figure 6.3-80
EOL HFP RCCA Ejection (Nuclear Power vs. Time)

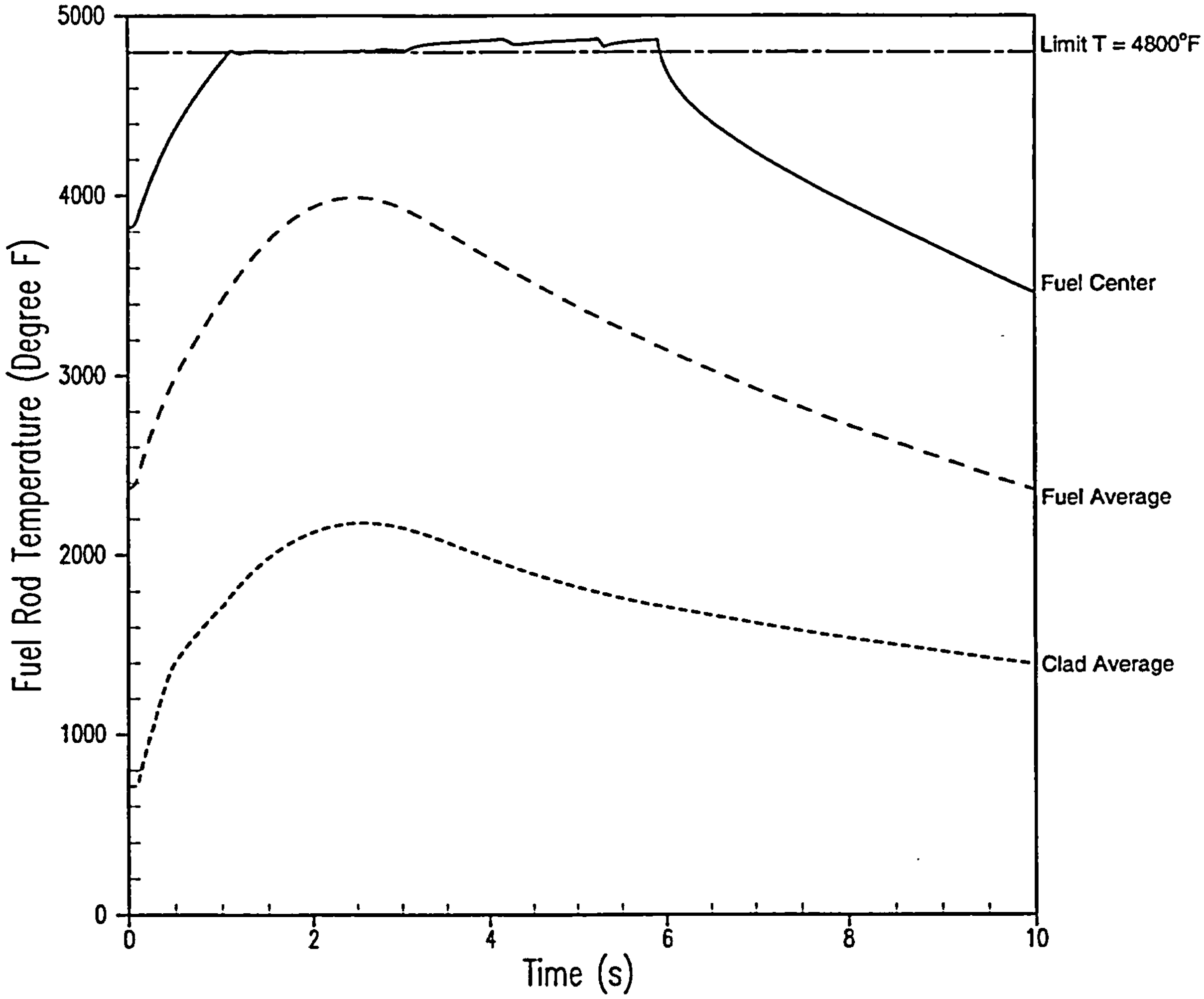


Figure 6.3-81

EOL HFP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

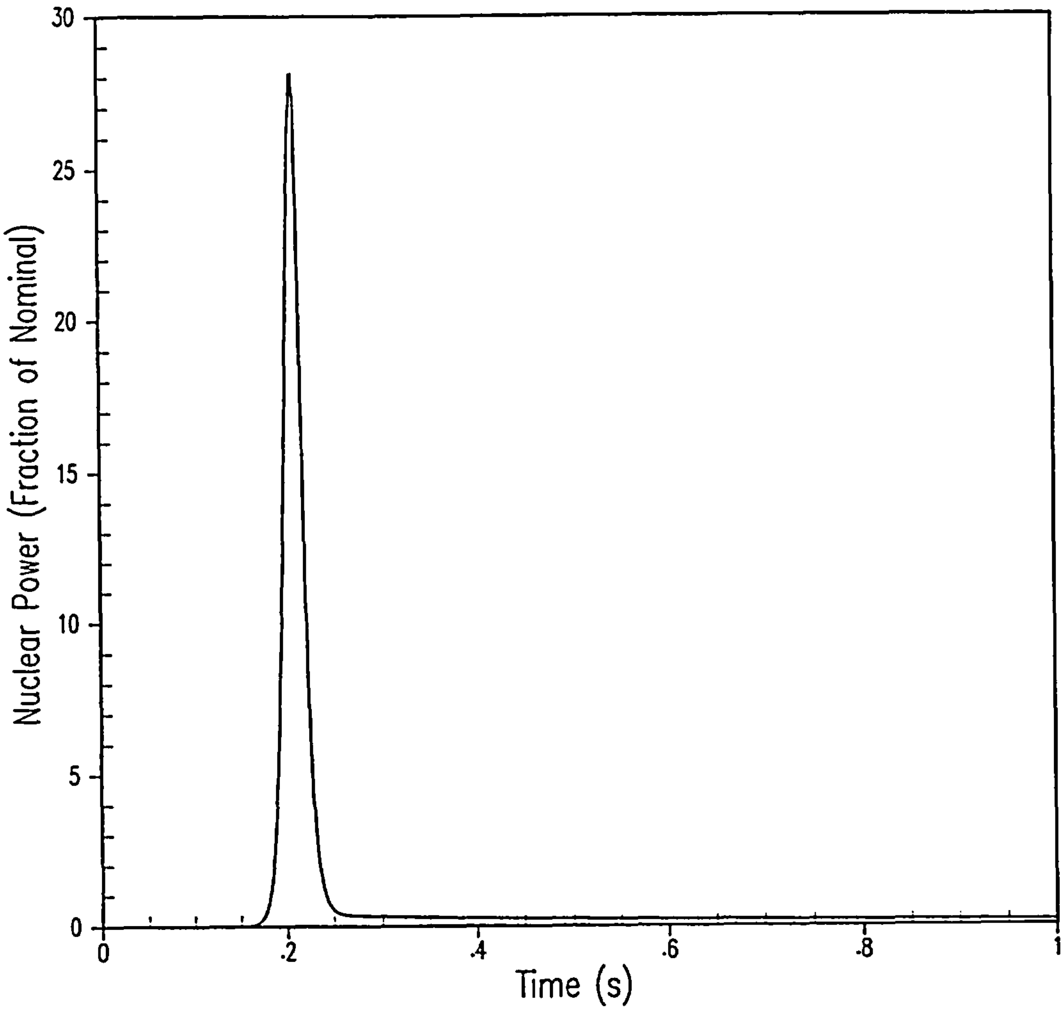


Figure 6.3-82

EOL HZP RCCA Ejection (Nuclear Power vs. Time)

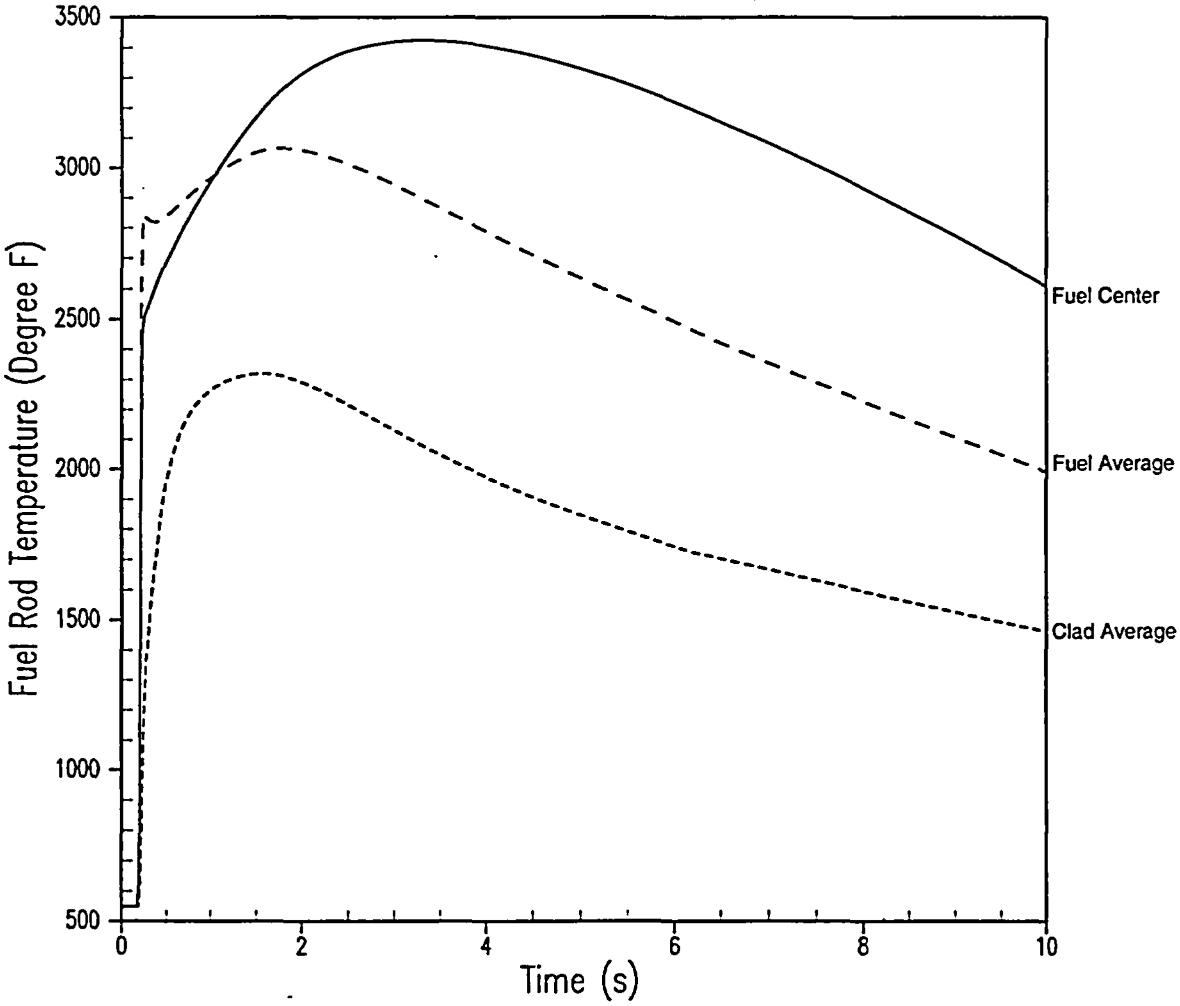


Figure 6.3-83

EOL HZP RCCA Ejection (Hot Spot Fuel and Clad Temperatures vs. Time)

6.4 Steam Generator Tube Rupture Transient

6.4.1 Thermal-Hydraulic Analysis for Offsite Radiological Consequences

In support of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), a steam generator tube rupture (SGTR) thermal-hydraulic analysis to calculate the radiological consequences has been performed. The analysis was performed using the Nuclear Steam Supply System (NSSS) design parameters for a power uprate to a nominal core power of 3216 MWt.

The major hazard associated with an SGTR event is the radiological consequences resulting from the transfer of radioactive reactor coolant to the secondary side of the ruptured steam generator and subsequent release of radioactivity to the atmosphere. The primary thermal-hydraulic parameters that affect the calculation of doses for an SGTR include the amount of reactor coolant transferred to the secondary side of the ruptured steam generator, the amount of primary-to-secondary break flow that flashes to steam and the amount of steam released from the ruptured steam generator to the atmosphere. The radiological consequences analysis will be discussed in subsection 6.11.9 of this report.

6.4.1.1 Input Parameters and Assumptions

The accident analyzed is the double-ended rupture of a single steam generator tube. It is assumed that the primary-to-secondary break flow following an SGTR results in depressurization of the Reactor Coolant System (RCS), and that reactor trip and safety injection (SI) are automatically initiated on low-pressurizer pressure. Loss-of-offsite power (LOOP) is assumed to occur at reactor trip resulting in the release of steam to the atmosphere via the steam generator atmospheric relief valves (ARVs) and/or safety valves. After plant trip and SI actuation, it is assumed that the RCS pressure stabilizes and the break flow equilibrates at the point where incoming SI flow is balanced by outgoing break flow as shown in Figure 6.4-1. The equilibrium primary-to-secondary break flow is assumed to persist until 30 minutes after the initiation of the SGTR, at which time it is assumed that the operators have completed the necessary actions to terminate the break flow and the steam releases from the ruptured steam generator.

The current analysis does not require that the operators demonstrate the ability to terminate break flow within 30 minutes from the start of the event. It is recognized that the operators may not be able to terminate break flow within 30 minutes for all postulated SGTR events. As discussed in the following paragraphs, the LOFTTR2 analysis supports operator actions to terminate break flow at 60 minutes. The purpose of the calculation is to provide conservatively high mass-transfer rates for use in the radiological consequences analysis. This is achieved by assuming a constant break flow at the equilibrium flow rate, with a constant flashing fraction that

does not credit the plant cooldown, for a relatively long time period. Thirty minutes was selected for this purpose. This modeling is consistent with the SGTR analysis presented in Section 14.2.4 of the current *Updated Final Safety Analysis Report* (UFSAR) (Reference 1).

In addition to the previously discussed licensing basis analysis, a supplemental plant response to the event was modeled using the LOFTTR2 computer code with conservative assumptions of break size and location, and condenser availability. The analysis methodology includes the simulation of the operator actions for recovery from an SGTR based on the IP3 Emergency Operating Procedures (EOPs), which are based on the Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs). Conservative operator action times were assumed for analysis purposes and are not intended to serve as a basis for actual operator action times in procedures or training.

The LOFTTR2 analyses were performed for the time period from the SGTR initiation until the primary and secondary pressures were equalized (break flow termination at 60 minutes). The water volume in the secondary side of the ruptured steam generator was calculated as a function of time to demonstrate that overfill does not occur. The primary-to-secondary break flow and steam releases to the atmosphere from both the ruptured and intact steam generators were calculated for use in determining the activity released to the atmosphere. The mass releases were calculated with the LOFTTR2 program from the initiation of the event until termination of the break flow. The mass release information was compared to the licensing basis analysis to verify that the licensing basis analysis modeling break flow for only 30 minutes is limiting with respect to offsite and control room doses.

After 30 minutes, it is assumed in the licensing basis analysis that steam is released only from the intact steam generators to dissipate the core decay heat and to subsequently cool the plant down to the Residual Heat Removal System (RHRS) operating conditions. It is assumed that the RHRS is capable of removing core decay heat within 29 hours after the SGTR initiation, and that steam releases are terminated at that time. A primary and secondary side mass and energy (M&E) balance is used to calculate the steam release for the intact steam generators from 0 to 2 hours, from 2 to 8 hours, and from 8 to 29 hours.

The following analysis assumptions and input parameters were used.

- Analysis methodology is consistent with current UFSAR analysis.
- LOOP is assumed to occur concurrent with the reactor trip.
- The core power is 3216 MWt.

- The RCS average temperature range is 549.0° to 572.0°F.

- The steam generator tube plugging (SGTP) range is 0 to 10 percent.

- The main feedwater temperature range is 390° to 433.6°F

- The low-pressurizer pressure SI actuation setpoint is 1734.7psia.

- The lowest steam generator safety valve reseat pressure is 885.4 psia. This includes an 18-percent main steam safety valve (MSSV) blowdown, which covers the -3-percent safety valve setpoint tolerance.

- The maximum high-head safety injection (HHSI) flow rates from all 3 HHSI pumps are shown below:

RCS Pressure (psia)	HHSI Flow Rate (gpm)
1014.7	834.9
1214.7	656.9
1414.7	420.6
1614.7	0.0

- In addition to the HHSI flow, the analysis models a charging flow of 108 gpm per pump for a total of 324 gpm from 3 pumps.

- The time the RHR is capable of removing all decay heat (termination of steam releases) is less than 29 hours after event initiation.

- The break-flow flashing fraction is calculated based on the initial hot leg temperature (603.0°F) for the pre-reactor trip break-flow flashing fraction. Following reactor trip, the break-flow flashing fraction is based upon a hot leg temperature equal to the saturation temperature of the RCS pressure where the break-flow rate equals SI flow rate (T_{sat}(1600 psia) = 604.9°F).

- The break-flow to the ruptured steam generator and steam releases from the ruptured steam generator is assumed to be terminated at 30 minutes.

- The minimum total auxiliary feedwater (AFW) flow rate supplied to the plant is 600 gpm.

6.4.1.2 Description of Analyses and Evaluations

The SGTR analysis supports an average temperature (T_{avg}) window range of 549.0°F up to 572.0°F. Plant secondary side conditions (for example, steam pressure, flow, and temperature) are based on high and low tube plugging (0-percent up to 10-percent average/peak) to bound all possible conditions. Four separate cases have been analyzed as follows:

1. T_{avg} = 549.0°F and SGTP = 0 percent
2. T_{avg} = 549.0°F and SGTP = 10-percent average/peak
3. T_{avg} = 572.0°F and SGTP = 0 percent
4. T_{avg} = 572.0°F and SGTP = 10-percent average/peak

In total, four cases were considered in the SGTR thermal-hydraulic analysis to bound the operating conditions for the uprate. Note that these four cases are individually analyzed to determine the limiting steam release and limiting break flow between 0 and 30 minutes (break-flow termination) for the radiological consequences calculation.

A portion of the break flow will flash directly to steam upon entering the secondary side of the ruptured steam generator. Since a transient break-flow calculation is not performed for IP3, a detailed time-dependent flashing fraction that incorporates the expected changes in primary side temperatures cannot be calculated. Instead, a conservative calculation of the flashing fraction is performed using the limiting conditions from the break-flow calculation cases. Two time intervals are considered, as in the break-flow calculations: pre- and post-reactor trip (SI initiation occurs concurrently with reactor trip). Since the RCS and steam generator conditions are different before and after the trip, different flashing fractions would be expected.

The flashing fraction is based on the difference between the primary side fluid enthalpy and the saturation enthalpy on the secondary side. Therefore, the highest flashing will be predicted for the case with the highest primary side temperatures. For the flashing-fraction calculations, it is conservatively assumed that all of the break flow is at the hot leg temperature (T_{hot}) (the break is assumed to be on the hot-leg side of the steam generator). Similarly, a lower secondary side pressure maximizes the difference in the primary and secondary enthalpies, resulting in more flashing. The highest possible pre-trip flashing fraction, based on the range of operating conditions covered by this analysis, is for a case with a T_{hot} of 603.0°F, an initial RCS pressure of 2250 psia, and an initial secondary pressure of 567 psia. All cases consider the same post-trip RCS pressure of 1600 psia and post-trip steam generator pressure of 885.4 psia. The post-trip flashing fraction is based on a hot leg temperature at saturation conditions with the RCS at the equilibrium pressure of 1600 psia.

A single calculation is performed to determine long-term steam releases from the intact steam generators for the time interval from the start of the event (0 hours) to 2 hours, 2 hours to 8 hours, and from 8 hours to RHR conditions at 29 hours. The 0- to 2-hour calculations use the 0- to 30-minute intact steam generators' steam release results from the case that resulted in the highest intact steam generators' steam flow rates.

A simple mass and energy (M&E) balance is assumed in the calculation of the break flow and steam releases. The energy balance is based on the following assumed conditions at 30 minutes:

- The RCS fluid is at the equilibrium pressure and no-load temperature.

- The pressurizer fluid and steam generator secondary fluid for both the ruptured and intact steam generators is at saturation conditions at the no-load temperature.

- The fuel and clad, primary system metal, pressurizer metal, and steam generator secondary metal are at no-load temperature. Since the RCS fluid is not at a consistent energy state with the ruptured steam generator and the remainder of the primary and secondary systems, energy must be dissipated to reduce the RCS fluid from equilibrium pressure and no-load temperature to saturation at no-load temperature.

It is assumed that the plant is then maintained stable at the no-load temperature until 2 hours, and that steam will be released from only the intact steam generators to dissipate the energy from the reduction in the RCS fluid energy state and the core decay heat from 30 minutes to 2 hours.

After 2 hours, it is assumed that plant cooldown to RHR cut-in conditions is initiated by releasing steam from only the intact steam generators. It is assumed that cooldown to RHR cut-in conditions is completed within 8 hours after the SGTR since the cooldown should be accomplished within this time period. However, at 8 hours the RHRS may not be capable of removing all the residual decay heat. Therefore, between 8 and 29 hours steam is released from the intact steam generators to remove the residual decay heat. After the RHR is capable of removing all decay heat, it is assumed that further cooldown is performed using the RHRS, and that the steam release from the intact steam generators is terminated. The energy to be dissipated from 2 to 8 hours and 8 to 29 hours is calculated from an energy balance for the primary and secondary systems between no-load conditions at 2 hours, and the RHR entry conditions at 8 hours, plus the core decay heat load from 2 to 8 hours and 8 to 29 hours. The amount of steam released from the intact steam generators is calculated from an M&E balance for the intact steam generators.

6.4.1.3 Acceptance Criteria

There are no criteria associated with the thermal-hydraulic calculations. The results of the calculations are used in the determination of the offsite and control room dose. Acceptance criteria for offsite and control room doses are discussed in subsection 6.11.9 of this report.

6.4.1.4 Results

The tube rupture break flow and ruptured steam generator atmospheric steam releases from 0 to 30 minutes for the four different SGTR cases (discussed in subsection 6.4.1.2 of this report) are summarized in Table 6.4-1. Based on the results of these four SGTR cases, bounding values for break flow and steam releases are provided in Table 6.4-2, along with the long-term steam releases, and steam generator water mass data to be used in radiological consequences analysis. For an SGTR event, the amount of radioactivity released to the atmosphere is highly dependent on the amount of steam released through the safety valves associated with the ruptured steam generator. Therefore, the worst radiological consequences result from the SGTR case with the greatest amount of steam released. Likewise, a greater break flow results in greater radiological contamination of the secondary side that, in turn, results in a greater amount of activity released along with the steam. Maximum break flow and steam release, therefore, represent bounding values that are conservative for an offsite and control room dose evaluation. An additional 10-percent margin has been added to the primary-to-secondary break flow and steam releases to allow for design changes.

The results of the radiological consequences analysis of an SGTR are discussed in subsection 6.11.9 of this document.

6.4.1.5 Conclusions

The SGTR thermal-hydraulic analysis to be used in the radiological consequences calculation has been completed in support of the IP3 SPU. Subsection 6.11.9 of this report presents the offsite and control room dose consequences based in the thermal-hydraulic data in Table 6.4-2.

6.4.2 References

1. *Indian Point Nuclear Generating Unit No.3, Updated Final Safety Analysis Report,* Docket No. 50-286.

Table 6.4-1

Case-Specific SGTR Thermal-Hydraulic Results[1]

Tube Rupture Break Flow for 0 - 30 min.	
T_{avg} = 549.0°F, 0% SGTP	124,901 lbm
T_{avg} = 549.0°F, 10% SGTP	125,118 lbm
T_{avg} = 572.0°F, 0% SGTP	122,401 lbm
T_{avg} = 572.0°F, 10% SGTP	123,213 lbm
Steam Release from Ruptured Steam Generator for Reactor Trip - 30 min.[2]	
T_{avg} = 549.0°F, 0% SGTP	51,922 lbm
T_{avg} = 549.0°F, 10% SGTP	50,768 lbm
T_{avg} = 572.0°F, 0% SGTP	65,192 lbm
T_{avg} = 572.0°F, 10% SGTP	62,002 lbm

Notes:

1. No margin added.
2. Prior to reactor trip, the steam flow rate is unaffected by the SGTR.

Table 6.4-2 **Bounding SGTR Thermal-Hydraulic Results for Radiological Dose Analysis[1]**	
Reactor Trip, SI Actuation, and LOOP	392 seconds
Pre-Trip (less than 392 sec)	
Tube Rupture Break Flow[1]	38,500 lbm
Percentage of Break Flow which Flashes	21.0%
Steam Release Rate to Condenser[1]	1070.21 lbm/sec for each steam generator
Post-Trip (after 392 sec)	
Tube Rupture Break Flow[1]	99,500 lbm
Percentage of Break Flow which Flashes	15.0%
Steam Release from Ruptured Steam Generator up to 30 minutes[1]	72,000 lbm
Steam Release from Intact Steam Generators up to 2 Hours[1]	526,000 lbm
Steam Release from Intact Steam Generator from 2 - 8 Hours[1]	1,160,000 lbm
Steam Release from Intact Steam Generator from 8 - 29 Hours[1]	1,580,000 lbm
Steam Generator Maximum Mass	90,000 lbm/steam generator
Steam Generator Minimum Mass	63,500 lbm/steam generator

Note:

1. 10-percent margin added on break flow and steam releases.

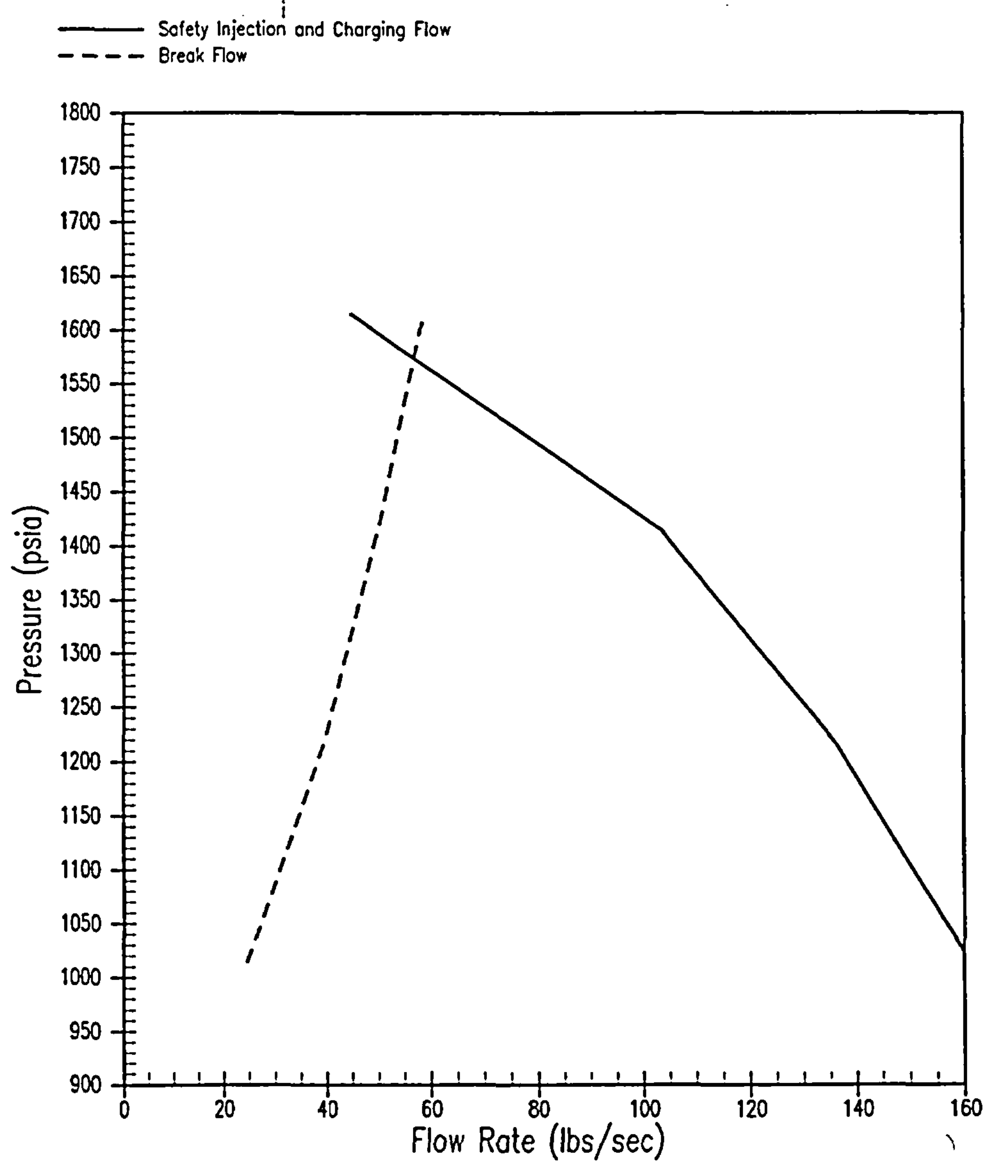


Figure 6.4-1

SI and Charging Flow and Break Flow versus RCS Pressure

6.5 Loss-of-Coolant Accident Containment Integrity

The uncontrolled release of pressurized high-temperature reactor coolant, termed a loss-of-coolant accident (LOCA), will result in release of steam and water into the containment. This, in turn, will result in increases in the local subcompartment pressures and an increase in the global containment pressure and temperature. Both the long-term and short-term effects on containment resulting from a postulated LOCA were considered for the stretch power uprate (SPU) at Indian Point Unit 3 (IP3).

To demonstrate the acceptability of the containment safeguards systems to mitigate the consequences of a hypothetical large-break LOCA (LBLOCA), the long-term LOCA mass and energy (M&E) releases were analyzed to approximately 10^7 seconds and used as input to the containment integrity analysis. The containment safeguards systems must be capable of limiting the peak containment pressure to less than the design pressure and to limit the temperature excursion to less than the Environmental Qualification (EQ) acceptance limits. In addition, the integrated leak rate test (ILRT) limit must not be exceeded. For this program, Westinghouse generated the M&E releases using the March 1979 model, described in WCAP-10325-P-A and WCAP-10326-A (Reference 1), which include the NRC review and approval letter. This methodology has previously been applied to IP3 and has also been used and approved on many plant-specific dockets. Subsection 6.5.1 of this report discusses the long-term LOCA M&E releases generated for this program. The results of this analysis were used in the containment integrity analysis (see subsection 6.5.3).

The short-term LOCA-related M&E releases are used as input to the subcompartment analyses, which are performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) accompanying a high-energy-line pipe rupture within that subcompartment. The subcompartments evaluated include the steam generator compartment, loop compartments, and the pressurizer compartment. The fact that IP3 is approved for leak-before-break (LBB) methodology was used to qualitatively demonstrate that any changes associated with the SPU are offset by the LBB benefit of using the smaller Reactor Coolant System (RCS) nozzle breaks, thus demonstrating that the current licensing bases for these subcompartments remain bounding. Any changes associated with the SPU will be offset by the LBB benefit and the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 2) will not change. Subsection 6.5.2 discusses the short-term evaluation conducted for this program.

6.5.1 Long-Term LOCA M&E Releases

The revised M&E release rates described in this section were used as input for the containment pressure calculations discussed in subsection 6.5.3. The M&E releases were revised using the *Westinghouse LOCA Mass and Energy Release Model for Containment Design, March 1979 Version* (Reference 1). The long-term LOCA M&E releases are provided for the hypothetical double-ended pump suction (DEPS) rupture and double-ended hot leg (DEHL) rupture cases for IP3 at the SPU conditions.

6.5.1.1 Input Parameters and Assumptions

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs were used and instrumentation uncertainties were included. For example, the RCS operating temperatures were chosen to bound the highest average coolant temperature range of all operating cases, and a temperature uncertainty allowance of +7.5°F was then added. Nominal parameters were used in certain instances. For example, the RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an uncertainty allowance (+49 psi). All input parameters were consistent with accepted analysis methodology.

Some of the most critical items were the RCS initial conditions, core decay heat, safety injection (SI) flow, and primary and secondary metal mass and steam generator heat release modeling. Specific assumptions concerning each of these items are discussed below. Tables 6.5-1 through 6.5-3 present key data assumed in the analysis.

The core-rated power of 3216 MWt was used in the analysis. The core-rated power uncertainty used in the long-term LOCA M&E analysis is 2 percent. As previously noted, RCS operating temperatures bounding the highest average coolant temperature range were used in the analysis. The use of higher temperatures is conservative because the initial fluid energy is based on coolant temperatures, which are at the maximum levels attained in steady-state operation. Additionally, an allowance to account for instrument error and deadband was reflected in the initial RCS temperatures. As previously discussed, the initial RCS pressure in this analysis was based on a nominal value of 2250 psia, plus an allowance that accounts for the measurement uncertainty on pressurizer pressure. The selection of 2299 psia as the limiting pressure is considered to affect the blowdown phase results only, since this represents the initial pressure of the RCS. The RCS rapidly depressurizes from this value to the point at which it equilibrates with containment pressure.

The rate at which the RCS blows down is initially more severe at the higher RCS pressure. Additionally, the RCS has a higher fluid density at the higher pressure (assuming a constant

temperature) and subsequently has a higher RCS mass available for releases. Thus, 2250 psia plus uncertainty was selected for the initial pressure as the limiting case for the long-term M&E release calculations.

The selection of the fuel design features for the long-term M&E release calculation is based on the need to conservatively maximize the energy stored in the fuel at the beginning of the postulated accident (that is, the core-stored energy). The core stored energy used is 4.90 full power seconds.

The RCS volume is increased by 3 percent, which is composed of a 1.6-percent allowance for thermal expansion and a 1.4-percent allowance for uncertainty.

A uniform steam generator tube plugging (SGTP) level of 0 percent was modeled. This assumption maximized the reactor coolant volume and fluid release by including the RCS fluid in all steam generator tubes. During the post-blowdown period, the steam generators are active heat sources since significant energy remains in the secondary metal and secondary mass that has the potential to be transferred to the primary side. The 0-percent SGTP assumption maximized heat transfer area and, therefore, the transfer of secondary heat across the steam generator tubes. Additionally, this assumption reduced the reactor coolant loop (RCL) resistance, which reduced the ΔP upstream of the break for the pump suction breaks and increased break flow. Thus, the analysis very conservatively modeled the effects related to SGTP.

The M&E release analyses modeled configurations and failure assumptions that conservatively bound alignments for SI flows. The minimum safeguards case that has a single failure of a diesel generator (DG) 32 (two high-head safety injection [HHSI] pumps and one low-head safety injection [LHSI] pump available). The maximum safeguards case has a single failure of one containment spray pump (three HHSI pumps and two LHSI pumps available).

The following assumptions were used to ensure that the M&E releases were conservatively calculated, thereby maximizing energy release to containment.

- Maximum expected operating temperature of the RCS (100 percent, full-power conditions)
- Allowance for RCS temperature uncertainty (+7.5°F)
- Margin in RCS volume of 3 percent (which is composed of a 1.6-percent allowance for thermal expansion, and 1.4 percent for uncertainty)

- Core-rated power of 3216 MWt
- Conservative heat transfer coefficient (that is, steam generator primary-to-secondary heat transfer and RCS metal heat transfer)
- Allowance in core-stored energy for the effect of fuel densification
- An allowance for RCS initial pressure uncertainty (+49 psi)
- A maximum containment backpressure equal to design pressure (61.7 psia)
- Minimum RCS loop flow (88,600 gpm/loop)
- Main feedwater addition following a signal to close the flow control valve
- SGTP leveling (0 percent uniform)
  - Maximizes reactor coolant volume and fluid release
  - Maximizes heat transfer area across the steam generator tubes
  - Reduces coolant loop resistance, which reduces the ΔP upstream of the break for the pump suction breaks, and increases break flow

Based on these conditions and assumptions, a bounding analysis of IP3 was made for the release of M&E from the RCS for a postulated LOCA at the SPU core power of 3216 MWt.

6.5.1.2 Description of Analyses

The evaluation model (EM) used for the long-term LOCA M&E release calculations is the March 1979 model described in WCAP-10325-P-A (Reference 1). This EM has been reviewed and approved generically by the NRC. The approval letter is included with WCAP-10325-P-A. This model has previously been applied to IP3, and also has been used and approved on the plant-specific dockets for other Westinghouse pressurized water reactors (PWRs).

This report section presents the long-term LOCA M&E releases generated in support of the IP3 SPU. These M&E releases were used in the containment integrity analysis discussed in subsection 6.5.3.

6.5.1.3 LOCA M&E Release Phases

The containment system receives M&E releases following a postulated rupture in the RCS. These releases continue over a time period that, for the LOCA M&E analysis, is typically divided into four phases.

1. **Blowdown** - the period of time from accident initiation (when the reactor is at steady-state operation) to the time that the RCS and containment reach an equilibrium state.

2. **Refill** - the period of time when the lower plenum is being filled by accumulator and Emergency Core Cooling System (ECCS) water. At the end of blowdown, a large amount of water remains in the cold legs, downcomer, and lower plenum. To conservatively consider the refill period for the purpose of containment M&E releases, it is assumed that this water is instantaneously transferred to the lower plenum along with sufficient accumulator water to completely fill the lower plenum. This allows an uninterrupted release of M&E to containment because the lower plenum is not filled over time. Thus, the refill period is conservatively neglected in the M&E release calculation because there is an instantaneous rather than mechanistic transfer of water to the lower plenum.

3. **Reflood** - begins when the water from the lower plenum enters the core and ends when the core is completely quenched.

4. **Post-Reflood (FROTH)** - the period following the reflood phase. For the pump suction break, a two-phase mixture exits the core, passes through the hot legs, and is superheated in the steam generators prior to exiting the break as steam. After the broken-loop steam generator cools, the break flow becomes two-phase.

6.5.1.4 Computer Codes

The M&E release evaluation model in WCAP-10325-P-A (Reference 1) comprises M&E release versions of the following codes: SATAN VI, WREFLOOD, FROTH, and EPITOME. These codes were used to calculate the long-term LOCA M&E releases for IP3.

SATAN VI calculates blowdown; the first portion of the thermal-hydraulic transient following break initiation, including pressure, enthalpy, density, M&E flowrates; and energy transfer between primary and secondary systems as a function of time.

The WREFLOOD code addresses the portion of the LOCA transient in which the core reflooding phase occurs after the primary coolant system has depressurized (blowdown) due to the loss of water through the break and water supplied by the ECCS refills the reactor vessel and provides

cooling to the core. The most important feature of WREFLOOD is the steam/water mixing model (see subsection 6.5.1.8.2 of this report).

FROTH models the post-reflood portion of the transient. The FROTH code is used for the steam generator heat addition calculation from the broken-loop and intact-loop steam generators.

EPITOME continues the FROTH post-reflood portion of the transient from the time at which the secondary equilibrates to containment design pressure to the end of the transient. It also compiles a summary of data on the entire transient, including formal instantaneous M&E release tables and M&E balance tables with data at critical times.

6.5.1.5 Break Size and Location

Generic studies have been performed to determine the limiting postulated break size for LOCA M&E releases. The double-ended guillotine break has been determined to be limiting due to larger mass flow rates during the blowdown phase of the transient. During the reflood and post-reflood phases, the break size has little effect on the releases.

Three distinct locations in the RCS loop can be postulated for pipe rupture for any release purposes:

- Hot leg (between vessel and steam generator)
- Cold leg (between pump and vessel)
- Pump suction (between steam generator and pump)

The break locations analyzed for the SPU are the DEPS rupture (10.48 ft^2), and the DEHL rupture (9.18 ft^2). Break M&E releases have been calculated for the blowdown, reflood, and post-reflood phases of the LOCA for the DEPS cases. For the DEHL case, the releases were calculated only for the blowdown. The following information provides a discussion for each break location.

The DEHL rupture has been shown in previous studies to result in the highest blowdown M&E release rates. Although the core flooding rate would be the highest for this break location, the amount of energy transferred from the steam generator secondary side is minimal because the majority of the fluid that exits the core vents directly to containment, bypassing the steam generators. As a result, the reflood M&E releases were reduced significantly as compared to either the pump suction or cold leg break locations for which the core exit mixture must pass through the steam generators before venting through the break. For the hot leg break, generic studies have confirmed that there is no reflood peak (that is, from the end of the blowdown

period the containment pressure would continually decrease). Therefore, only the M&E releases for the hot leg break blowdown phase were calculated and presented in this section of the report.

The cold leg break location has also been determined in previous studies to be much less limiting in terms of the overall containment energy releases. The cold leg blowdown is faster than that of the pump suction break, and more mass is released into the containment. However, the core heat transfer is greatly reduced, and this results in a considerably lower energy release into containment. Studies have determined that the blowdown transient for the cold leg is, in general, less limiting than that for the pump suction break. During reflood, the flooding rate is greatly reduced and the energy release rate into the containment is reduced. Therefore, the cold leg break is bounded by other breaks and no further evaluation is necessary.

The pump suction break combines the effects of the relatively high core flooding rate, as in the hot leg break, and the addition of the stored energy in the steam generators. As a result, the pump suction break yields the highest energy flow rates during the post-blowdown period by including all of the available energy of the RCS in calculating the releases to containment.

6.5.1.6 Application of Single-Failure Criterion

An analysis of the effects of the single-failure criterion has been performed on the M&E release rates for each break analyzed. An inherent assumption in the generation of the M&E release is that offsite power is lost. This results in the actuation of the emergency diesel generators (DGs), which are required to power the Safety Injection System (SIS). This is not an issue for the blowdown period, which is limited by the DEHL break.

Two cases have been analyzed to assess the effects of a single failure. The first case assumes minimum ECCS SI flow based on the postulated single failure of a DG. This results in the loss of one train of safeguards equipment. The other case assumes maximum ECCS SI flow based on no postulated failures that would affect the amount of ECCS flow; one containment spray pump is failed. The analysis of these two cases provides confidence that the effect of credible single failures is bounded.

6.5.1.7 Acceptance Criteria for Analyses

An LBLOCA is classified as an American Nuclear Society (ANS) Condition IV event—an infrequent fault. Although IP3 is not a *Standard Review Plan* (SRP) plant, for completeness, the SRP long-term cooling criterion is also examined. To satisfy the NRC acceptance criteria presented in the SRP, Section 6.2.1.3, the relevant requirements are as follows:

- 10CFR50, Appendix A (Reference 3)
- 10CFR50, Appendix K, paragraph I.A (Reference 4)

To meet these requirements, the following must be addressed:

- Sources of energy
- Break size and location
- Calculation of each phase of the accident

6.5.1.8 M&E Release Data

6.5.1.8.1 Blowdown M&E Release Data

The SATAN-VI code is used for computing the blowdown transient. The code uses the control volume (element) approach with the capability for modeling a large variety of thermal fluid system configurations. The fluid properties are considered uniform and thermo-dynamic equilibrium is assumed in each element. A point kinetics model is used with weighted feedback effects. The major feedback effects include moderator density, moderator temperature, and Doppler broadening. A critical flow calculation for sub-cooled (modified Zaloudek), two-phase (Moody), or superheated break flow is incorporated into the analysis. The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1).

Table 6.5-4 presents the calculated M&E release for the blowdown phase of the DEHL break. For the hot leg break M&E release tables, break path 1 refers to the M&E exiting from the reactor vessel side of the break, and break path 2 refers to the M&E exiting from the steam generator side of the break. Table 6.5-5 presents the mass balance for the DEHL break. Table 6.5-6 presents the energy balance for the DEHL break.

Table 6.5-7 presents the calculated M&E releases for the blowdown phase of the DEPS break with minimum ECCS flows. Table 6.5-8 presents the calculated M&E releases for the blowdown phase of the DEPS break with maximum ECCS flows. For the pump suction breaks, break path 1 in the M&E release tables refers to the M&E exiting from the steam-generator side of the break; break path 2 refers to the M&E exiting from the pump side of the break.

6.5.1.8.2 Reflood M&E Release Data

The WREFLOOD code is used for computing the reflood transient. The WREFLOOD code consists of two basic hydraulic models: one for the contents of the reactor vessel, and one for the coolant loops. The two models are coupled through the interchange of the boundary conditions applied at the vessel outlet nozzles and at the top of the downcomer. Additional transient phenomena, such as pumped SI and accumulators, reactor coolant pump (RCP) performance, and steam generator releases are included as auxiliary equations that interact with the basic models as required. The WREFLOOD code permits the capability to calculate variations during the core reflooding transient of basic parameters, such as core flooding rate, core and downcomer water levels, fluid thermo-dynamic conditions (pressure, enthalpy, density) throughout the primary system, and mass flow rates through the primary system. The code permits hydraulic modeling of the two flow paths available for discharging steam and entrained water from the core to the break; that is, the path through the broken loop and the path through the unbroken loops.

A complete thermal equilibrium mixing condition for the steam and ECCS injection water during the reflood phase has been assumed for each loop receiving ECCS water. This is consistent with the use and application of the M&E release evaluation model (Reference 1) in recent analyses, for example, D. C. Cook Docket (Reference 5). Even though the WCAP-10325-P-A (Reference 1) model credits steam/water mixing only in the intact loop and not in the broken loop, the justification, applicability, and NRC approval for using the mixing model in the broken loop has been documented (Reference 5). Moreover, this assumption is supported by test data and is further discussed below.

The model assumes a complete mixing condition (that is, thermal equilibrium) for the steam/water interaction. The complete mixing process, however, is made up of two distinct physical processes. The first is a two-phase interaction with steam condensation by cold ECCS water. The second is a single-phase mixing of condensate and ECCS water. Since the steam release is the most important influence to the containment pressure transient, the steam condensation part of the mixing process is the only part that must be considered. (Any spillage directly heats only the sump.)

The most applicable steam/water mixing test data have been reviewed for validation of the containment integrity reflood steam/water mixing model. These data were generated in 1/3-scale tests (Reference 6) and are the largest scale data available and, thus, most clearly simulate the flow regimes and gravitational effects that would occur in a PWR. These tests were designed specifically to study the steam/water interaction for PWR reflood conditions.

A group of 1/3-scale tests corresponds directly to containment integrity reflood conditions. The injection flowrates for this group cover all phases and mixing conditions calculated during the reflood transient. The data from these tests were reviewed and discussed in detail in WCAP-10325-P-A (Reference 1). For all of these tests, the data clearly indicate the occurrence of very effective mixing with rapid steam condensation. The mixing model used in the containment integrity reflood calculation is, therefore, wholly supported by the 1/3-scale steam/water mixing data.

Additionally, the following justification is also noted. The post-blowdown limiting break for the containment integrity peak pressure analysis is the DEPS rupture. For this break, there are two flow paths available in the RCS by which M&E can be released to containment. One is through the outlet of the steam generator, the other via reverse flow through the RCP. Steam that is not condensed by ECCS injection in the intact RCS loops passes around the downcomer and through the broken-loop cold leg and pump-in venting to containment. This steam also encounters ECCS injection water as it passes through the broken-loop cold leg, where complete mixing occurs, and a portion of it is condensed. It is this portion of steam, which is condensed, that is credited in this analysis. Based upon the postulated break location and the actual physical presence of the ECCS injection nozzle, this assumption is justified. A description of the test and the test results are contained in WCAP-10325-P-A and EPRI 294-2 (References 1 and 6).

Tables 6.5-9 and 6.5-10 present the calculated M&E releases for the reflood phase of the DEPS minimum ECCS and maximum ECCS cases, respectively.

The transient response of the principal parameters during reflood are given in Tables 6.5-11 and 6.5-12 for the DEPS cases.

6.5.1.8.3 Post-Reflood M&E Release Data

The FROTH code (Reference 7) is used for computing the post-reflood transient. The FROTH code calculates the heat release rates from the steam generator metal and secondary side water to the two-phase mixture present in the steam generator tubes. The M&E releases that occur during this phase are typically superheated due to the depressurization and equilibration of the broken-loop and intact-loop steam generators. During this phase of the transient, the RCS has equilibrated with the containment pressure, but the steam generators contain a secondary inventory at an enthalpy that is much higher than the primary side, therefore, a significant amount of reverse heat transfer occurs. Steam is produced in the core due to core decay heat. For a pump suction break, a two-phase fluid exits the core, flows through the hot legs and becomes superheated as it passes through the steam generator. Once the broken loop cools, the break flow becomes two-phase. In the FROTH calculation, ECCS injection is

addressed for both the injection phase and the recirculation phase. The FROTH code calculation stops when the secondary side equilibrates to the saturation temperature (T_{sat}) at the containment design pressure. After this point, the EPITOME code completes the steam generator depressurization (see subsection 6.5.1.8.5 of this document for additional information).

The methodology for the use of this model is described in WCAP-10325-P-A (Reference 1). The M&E release rates are calculated by FROTH and EPITOME until the time of containment depressurization. After containment depressurization (14.7 psia), the M&E release available to containment is generated directly from core boil off/decay heat.

Tables 6.5-13 and 6.5-14 present the two-phase post-reflood M&E release data for the DEPS cases, minimum and maximum ECCS assumptions, respectively.

6.5.1.8.4 Decay Heat Model

On November 2, 1978, the Nuclear Power Plant Standards Committee (NUPPSCO) of the ANS approved ANS Standard 5.1 (Reference 8) for the determination of decay heat. This standard was used in the M&E release. Table 6.5-15 lists the decay heat curve used in the M&E release analysis, post-blowdown, for the IP3 SPU.

Significant assumptions in the generation of the decay heat curve for use in the LOCA M&E releases analysis include the following:

- Decay heat sources considered are fission product decay and heavy element decay of U-239 and Np-239.
- Decay heat power from fissioning isotopes other than U-235 is assumed to be identical to that of U-235.
- Fission rate is constant over the operating history of maximum power level.
- The factor accounting for neutron capture in fission products has been taken from Equation 11 up to 10,000 seconds and from Table 10, both of ANSI/ANS-5.1 (Reference 8), beyond 10,000 seconds.
- The fuel has been assumed to be at full power for 10^8 seconds.
- The number of atoms of U-239 produced per second has been assumed to be equal to 70 percent of the fission rate.

- The total recoverable energy associated with one fission has been assumed to be 200 MeV/fission.

- Two-sigma uncertainty (two times the standard deviation) has been applied to the fission product decay.

Based upon the NRC staff review as indicated in the *Safety Evaluation Report* (SER) of WCAP-10325-P-A (Reference 1), use of the ANS Standard-5.1, November 1979 decay heat model was approved for the calculation of M&E releases to the containment following a LOCA.

6.5.1.8.5 Steam Generator Equilibration and Depressurization

Steam generator equilibration and depressurization is the process by which secondary side energy is removed from the steam generators in stages. The FROTH computer code calculates the heat removal from the secondary mass until the secondary temperature is the saturation temperature (T_{sat}) at the containment design pressure. After the FROTH calculations, the EPITOME code continues the calculation for steam generator cooldown by removing steam generator secondary energy at different rates (that is, first and second stage rates). The first stage rate is applied until the steam generator reaches T_{sat} at the user-specified intermediate equilibration pressure, when the secondary pressure is assumed to reach the actual containment pressure. Then, the second stage rate is used until the final depressurization, when the secondary reaches the reference temperature of T_{sat} at 14.7 psia, or 212°F. The heat removal of the broken-loop and intact-loop steam generators are calculated separately.

In the FROTH calculations, steam generator heat removal rates were calculated using the secondary side temperature, primary side temperature, and a secondary side heat transfer coefficient determined using a modified McAdam's correlation. Steam generator energy is removed during the FROTH transient until the secondary side temperature reaches the saturation temperature at the containment design pressure (61.7 psia). The constant heat removal rate used during the first heat removal stage is based on the final heat removal rate calculated by FROTH. The steam generator energy available to be released during the first stage interval is determined by calculating the difference in secondary energy available at the containment design pressure, and that at the (lower) user-specified intermediate equilibration pressure, assuming saturated conditions. This energy is then divided by the first stage energy removal rate, resulting in an intermediate equilibration time. At this time, the rate of energy release drops substantially to the second stage rate. The second stage rate is determined as the fraction of the difference in secondary energy available between the intermediate equilibration and final depressurization at 212°F, and the time difference from the time of the intermediate equilibration to the user-specified time of the final depressurization at 212°F. With the current methodology, all of the secondary energy remaining after the intermediate

equilibration is conservatively assumed to be released by imposing a mandatory cooldown and subsequent depressurization down to atmospheric pressure at 3600 seconds, that is, 14.7 psia and 212°F.

6.5.1.8.6 Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are given in Tables 6.5-5, 6.5-16, and 6.5-17. These sources are the RCS, accumulators, and pumped SI.

The energy inventories considered in the LOCA M&E release analysis are given in Tables 6.5-6, 6.5-18, and 6.5-19. The energy sources include:

- RCS water
- Accumulator water (all four inject)
- Pumped SI water
- Decay heat
- Core-stored energy
- RCS metal (includes steam generator tubes)
- Steam generator metal (includes transition cone, shell, wrapper, and other internals)
- Steam generator secondary energy (includes fluid mass and steam mass)
- Secondary transfer of energy (feedwater into and steam out of the steam generator secondary; feedwater pump coastdown after the signal to close the flow control valve)

Energy reference points are the following:

- Available energy: 212°F, 14.7 psia
- Total energy content: 32°F, 14.7 psia

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions)
- End-of-blowdown time
- End-of-refill time
- End-of-reflood time
- Time of broken-loop steam generator equilibration to pressure setpoint
- Time of intact-loop steam generator equilibration to pressure setpoint
- Time of full depressurization (3600 seconds)

In the M&E release data presented, no zirconium-water reaction heat was considered because the clad temperature is assumed not to rise high enough for the zirconium-water reaction heat to be of any significance.

The sequence of events for the LOCA transients are shown in Tables 6.5-20 through 6.5-22.

6.5.1.8.7 Conclusions

The consideration of the various energy sources in the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. Thus, the review guidelines presented in SRP Section 6.2.1.3 have been satisfied. The results of this analysis are used in the containment integrity analysis, as shown in subsection 6.5.3.

6.5.2 Short-Term LOCA M&E Releases

6.5.2.1 Purpose

An evaluation was conducted to determine the effect of the IP3 SPU on the short-term LOCA-related M&E releases that support subcompartment analyses discussed in the IP3 UFSAR (Reference 2). IP3 has been licensed for the application of LBB technology (Reference 9).

6.5.2.2 Discussion and Evaluation

The subcompartment analysis is performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 3 seconds) that accompanies a high-energy line pipe rupture within the subcompartment. The magnitude of the pressure differential across the walls is a function of several parameters, which include the blowdown M&E release rates, the subcompartment volume, vent areas, and vent flow behavior. The blowdown M&E release rates are affected by the initial RCS temperature conditions. Since short-term releases are linked directly to the critical mass flux, which increases with decreasing temperatures, the short-term LOCA releases would be expected to increase due to any reductions in RCS coolant temperature conditions. Short-term blowdown transients are characterized by a peak M&E release rate that occurs during a sub-cooled condition; thus, the Zaloudek correlation, which models this condition, is currently used in the short-term LOCA M&E release analyses with the SATAN computer program.

This calculation was used to conservatively evaluate the effect of the changes in RCS temperature conditions due to the SPU conditions on the short-term releases. This was accomplished by maximizing the reservoir pressure and minimizing the RCS inlet and outlet temperatures for the original Analysis of Record (AOR), and by minimizing the RCS inlet and

outlet temperatures for the SPU data. Since this maximizes the change in short-term LOCA M&E releases, data representative of the lowest inlet and outlet temperatures with uncertainty subtracted were used for the SPU evaluation of short-term M&E releases.

For this evaluation, an RCS pressure of 2299 psia, a vessel/core inlet temperature of 511.8°F, and a hot leg temperature of 574.8°F were used.

Current Licensing Basis Analyses

IP3 is approved for LBB (Reference 9) for the primary loop, and LBB eliminates the dynamic effects of these pipe ruptures from the design basis. This means that the current RCL breaks no longer have to be considered for subcompartment short-term effects. Since these breaks have been eliminated, the next largest branch nozzles must be considered for design verification. The LBB cases that have been evaluated for IP3 are a hot leg break, a cold leg break, a surge line break, an accumulator line break or a residual heat removal (RHR) line break. The evaluations determined that the increase in subcompartment pressurization due to the lower SPU RCS temperatures resulted in at least 72.9-percent margin to the current AOR.

6.5.2.3 Results and Conclusion

The short-term LOCA-related M&E releases discussed in Chapter 14.3 of the UFSAR (Reference 2) have been reviewed to assess the effects associated with the SPU conditions for IP3. Since IP3 is approved for LBB, the decrease in M&E releases associated with the smaller RCS branch line breaks, as compared to the larger RCS pipe breaks, more than offsets the effects associated with the IP3 SPU conditions.

6.5.3 Long-Term LOCA Containment Response

6.5.3.1 Accident Description

The IP3 containment systems are designed such that for all LOCA break sizes, up to and including the double-ended severance of a reactor coolant pipe, the containment peak pressure remains below the design pressure and the ILRT limit. This section discusses the containment response subsequent to a hypothetical LOCA. The containment response analysis uses the long-term M&E release data from subsection 6.5.1 of this document.

The containment response analysis demonstrates the acceptability of the containment safeguards systems to mitigate the consequences of a LOCA inside containment. The effect of LOCA M&E releases on the containment pressure is addressed to assure that the containment pressure remains below its design pressure and the ILRT limit at the SPU conditions. In

support of equipment design and licensing criteria (for example, qualified operating life), long-term containment pressure and temperature transients for post-accident environmental conditions are generated to conservatively bound the potential post-LOCA containment conditions.

6.5.3.2 Input Parameters and Assumptions

An analysis of containment response to the rupture of the RCS must start with knowledge of the initial conditions in the containment. The pressure, temperature, and humidity of the containment atmosphere prior to the postulated accident are specified for the analysis as shown in Table 6.5-23.

Values for the initial temperature of the service water (SW) and refueling water storage tank (RWST) water have been specified, along with containment spray (CS) pump flowrate and reactor containment fan cooler (RCFC) heat removal performance. These values (shown in Tables 6.5-23 and 6.5-24) are chosen conservatively. Long-term sump recirculation is addressed via Residual Heat Removal System (RHRS) heat exchanger performance. The primary function of the RHRS is to remove heat from the core by using the ECCS. Table 6.5-23 provides the RHRS parameters assumed in the analysis.

A series of cases were performed for the LOCA containment response. Subsection 6.5.1 documented the M&E releases for the minimum and maximum ECCS cases for a DEPS break and the releases from the blowdown of a DEHL break.

For the maximum ECCS DEPS case, the failure of a containment spray pump was assumed as the single failure, which leaves available as active heat removal systems one containment spray pump and five RCFCs. Table 6.5-25 provides the performance data for one spray pump in operation. Emergency safeguards equipment data are given in Table 6.5-23.

The minimum ECCS DEPS case was based upon a diesel train failure, DG 32, (which leaves available as active heat removal systems one containment spray pump and four RCFCs). The failure of each DG (31, 32 and 33) was analyzed to determine the most limiting case; the single failure of DG 32 resulted in the highest peak pressure, so the single failure of DG 32 was used in all of the minimum ECCS cases.

Due to the duration of the DEHL transient (that is, blowdown only), no containment safeguards equipment is modeled.

The calculations for the DEPS minimum ECCS and maximum ECCS cases were performed for 10^7 seconds (approximately 115 days). The DEHL cases were terminated soon after the end of

the blowdown. The sequence of events for each of these cases is shown in Tables 6.5-26 through 6.5-28.

The following are the major assumptions made in the analysis.

- The M&E released to the containment for LOCA are described in subsection 6.5.1 of this document.

- Homogeneous mixing is assumed. The steam-air mixture and the water phases each have uniform properties. More specifically, thermal equilibrium between the air and the steam is assumed. However, this does not imply thermal equilibrium between the steam-air mixture and the water phase.

- Air is taken as an ideal gas, while compressed water and steam tables are used for water and steam thermodynamic properties.

- For the blowdown portion of the LOCA analysis, the discharge flow separates into steam and water phases at the breakpoint. The saturated water phase is at the total containment pressure, while the steam phase is at the partial pressure of the steam in the containment. For the post-blowdown portion of the LOCA analysis, steam and water releases are input separately.

- The saturation temperature at the partial pressure of the steam is used for heat transfer to the heat sinks and the containment fan coolers.

6.5.3.3 Description of COCO Model

Calculation of containment pressure and temperature is accomplished by use of the digital computer code COCO (Reference 10). COCO is a mathematical model of a generalized containment; the proper selection of various options in the code allows the creation of a specific model for particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and determined to be acceptable to calculate containment pressure transients for many dry containment plants, most recently including Vogtle Units 1 and 2, Turkey Point Unit 3, Salem Units 1 and 2, Diablo Canyon Units 1 and 2, IP3, and Indian Point Unit 2 (IP2). Transient phenomena within the RCS affect containment conditions by means of convective M&E transport through the pipe break.

For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water-phase and a steam-air phase. Sufficient relationships to describe the transient are

provided by the equations of conservation of M&E as applied to each system, together with appropriate boundary conditions. As thermodynamic equations of state and conditions may vary during the transient, the equations have been derived for possible cases of superheated or saturated steam, and subcooled or saturated water. Switching between states is handled automatically by the code.

Passive Heat Removal

The significant heat removal source during the early portion of the transient is the containment structural heat sinks. Provision is made in the containment pressure response analysis for heat transfer through, and heat storage in, both interior and exterior walls. Each wall is divided into a large number of nodes. For each node, a conservation of energy equation expressed in finite-difference form accounts for heat conduction into and out of the node and temperature rise of the node. Table 6.5-29 is the summary of the containment structural heat sinks used in the analysis. The thermal properties of each heat sink material are shown in Table 6.5-30.

The heat transfer coefficient to the containment structure for the early part of the event is calculated based primarily on the work of Tagami (Reference 11). From this work, it was determined that the value of the heat transfer coefficient can be assumed to increase parabolically to a peak value. In COCO, the value then decreases exponentially to a stagnant heat transfer coefficient that is a function of steam-to-air-weight ratio. The heat transfer coefficient (h) for stagnant conditions is based upon Tagami's steady state results.

Tagami presents a plot of the maximum value of the heat transfer coefficient, (h), as function of "coolant energy transfer speed," defined as follows:

$$h = \frac{\text{total coolant energy transferred in to containment}}{(\text{containment volume})(\text{time interval to peak pressure})}$$

From this, the maximum heat transfer coefficient of steel is calculated:

$$h_{max} = 75\left(\frac{E}{t_p V}\right)^{0.60} \qquad \text{(Equation 1)}$$

where:

h_{max} = maximum value of h (Btu / hr ft^2 °F)

t_p = time from start of accident to end of blowdown for LOCA and steam line isolation for secondary breaks (sec)

V = containment net free volume (ft^3)
E = total coolant energy discharge from time zero to t_p (Btu)
75 = material coefficient for steel

(Note: Paint is addressed by the thermal conductivity of the material [paint] on the heat sink structure, not by an adjustment on the heat transfer coefficient.) The basis for the equations is a Westinghouse curve fit to the Tagami data.

The parabolic increase to the peak value is calculated by COCO according to the following equation:

$$h_s = h_{max}\left(\frac{t}{t_p}\right)^{0.5}, 0 \le t \le t_p \qquad \text{(Equation 2)}$$

where:

h_s = heat transfer coefficient between steel and air/steam mixture (Btu / hr ft^2 °F)
t = time from start of event (sec)

For concrete, the heat transfer coefficient is taken as 40 percent of the value calculated for steel during the blowdown phase.

The exponential decrease of the heat transfer coefficient to the stagnant heat transfer coefficient is given by:

$$h_s = h_{stag} + (h_{max} - h_{stag})e^{-0.05(t-t_p)} \qquad t > t_p \qquad \text{(Equation 3)}$$

where:

h_{stag} = $2 + 50X, 0 < X < 1.4$
h_{stag} = h for stagnant conditions (Btu / hr ft^2 °F)
X = steam-to-air weight ratio in containment

Active Heat Removal

For a large break, the engineered safety features (ESFs) are quickly brought into operation. Because of the brief period of time required to depressurize the RCS or the main steam system, the containment safeguards are not a major influence on the blowdown peak pressure;

however, they reduce the containment pressure after the blowdown and maintain a low, long-term pressure and a low, long-term temperature.

RWST, Injection

During the injection phase of post-accident operation, the ECCS pumps water from the RWST into the reactor vessel. Since this water enters the vessel at RWST temperature, which is less than the temperature of the water in the vessel, it is modeled as absorbing heat from the core until the saturation temperature is reached. SI and CS can be operated for a limited time, depending on the RWST capacity.

RHR, Sump Recirculation

After the supply of refueling water is exhausted, the recirculation system is operated to provide long term cooling of the core. In this operation, water is drawn from the sump, cooled in an RHR heat exchanger then pumped back into the reactor vessel to remove core residual heat and energy stored in the vessel metal. The heat is removed from the RHR heat exchanger by the component cooling water (CCW). The RHR heat exchangers and CCW heat exchangers are coupled in a closed-loop system, for which the ultimate heat sink (UHS) is the SW cooling to the CCW heat exchangers.

Containment Spray

CS is an active removal mechanism, which is used for rapid pressure reduction and for containment iodine removal. During the injection phase of operation, the CS pumps draw water from the RWST and spray it into the containment through nozzles mounted high above the operating deck. As the spray droplets fall, they absorb heat from the containment atmosphere. Since the water comes from the RWST, the entire heat capacity of the spray from the RWST temperature to the temperature of the containment atmosphere is available for energy absorption. During the recirculation phase, the spray is provided by diverting some of the LHSI to the spray rings. However, no credit was taken for recirculation spray in calculating the peak containment pressure.

When a spray droplet enters the hot, saturated steam-air containment environment, the vapor pressure of the water at its surface is much less than the partial pressure of the steam in the atmosphere. Hence, there will be diffusion of steam to the drop surface and condensation on the droplet. This mass flow will carry energy to the droplet. Simultaneously, the temperature difference between the atmosphere and the droplet will cause the droplet temperature and vapor pressure to rise. The vapor pressure of the droplet will eventually become equal to the

partial pressure of the steam, and the condensation will cease. The temperature of the droplet will essentially equal the temperature of the steam-air mixture.

The equations describing the temperature rise of a falling droplet are as follows:

$$\frac{d}{dt}(Mu) = mh_g + q \qquad \text{(Equation 4)}$$

where:

M	=	droplet mass (lbm)
u	=	internal energy (Btu)
m	=	diffusion rate (lbm/sec)
h_g	=	steam enthalpy (Btu/lbm)
q	=	heat flow rate (Btu/sec)
t	=	time (sec)

Note that

$$\frac{d}{dt}(M) = m \qquad \text{(Equation 5)}$$

where:

q	=	$h_c A * (T_s - T)$
q	=	heat flow rate (Btu/hr)
m	=	$k_g A * (P_s - P_v)$
m	=	mass flow rate (lbm/hr)
A	=	drop surface area (ft^2)
h_c	=	coefficient of heat transfer (Btu / hr ft^2 °F)
k_g	=	coefficient of mass transfer (lbm / hr ft^2 psi)
T	=	droplet temperature (°F)
T_s	=	steam temperature (°F)
P_s	=	steam partial pressure (psi)
P_v	=	droplet vapor pressure (psi)

The coefficients of heat transfer (h_c) and mass transfer (k_g) are calculated from the Nusselt number for heat transfer, Nu, and the Nusselt number for mass transfer, Nu'.

Both Nu and Nu' may be calculated from the equations of Ranz and Marshall (Reference 12).

$$Nu = 2 + 0.6(Re)^{1/2}(Pr)^{1/3} \qquad \text{(Equation 6)}$$

where:

Nu = Nusselt number for heat transfer
Pr = Prandtl number
Re = Reynolds number

$$Nu' = 2 + 0.6(Re)^{1/2}(Sc)^{1/3} \quad \text{(Equation 7)}$$

where,

Nu' = Nusselt number for mass transfer
Sc = Schmidt number

Thus, Equations 4 and 5 can be integrated numerically to find the internal energy and mass of the droplet as a function of time as it falls through the atmosphere. Analysis shows that the temperature of the (mass) mean droplet produced by the spray nozzles rises to a value within 99 percent of the bulk containment temperature in less than 2 seconds. Detailed calculations of the heatup of spray droplets in post-accident containment atmospheres by Parsly (Reference 13) show that droplets of the size encountered in the containment spray reach equilibrium in a fraction of their residence time in a typical PWR containment. These results confirm the assumption that the containment spray will be 100-percent effective in removing heat from the atmosphere.

RCFC

The RCFCs are another means of heat removal. Each RCFC has a fan that draws in the containment atmosphere from the upper volume of the containment via a return air riser. The RCFCs are cooled by the SW. The steam/air mixture is routed through the enclosed RCFC unit past essential SW cooling coils. The RCFC then discharges the air through ducting containing a check damper. The discharged air is directed at the lower containment volume. See Table 6.5-24 for the assumed RCFC heat removal capability for the containment response analyses.

6.5.3.4 Acceptance Criteria

A LOCA is an ANS Condition-IV event—an infrequent fault. The relevant requirements for the containment response for containment integrity to a design-basis LOCA are shown below.

- General Design Criteria (GDC) 10 (7/11/67) and GDC 49 (7/11/67) from the UFSAR (Reference 2), Chapter 5.1 requires that the peak calculated containment pressure does not exceed the containment design pressure of 47 psig.

- GDC 52 (7/11/67) from the UFSAR (Reference 2), Chapter 9.1 requires modeling of an active single failure to determine the response of the active heat removal systems.

- The UFSAR (Reference 2), Chapter 14.3 requires that the calculated pressure at 24 hours is less than 50 percent of the peak calculated pressure.

6.5.3.5 Analysis Results

The containment pressure, steam temperature, and water (sump) temperature profiles for the DEPS LOCA cases are shown in Figures 6.5-1 through 6.5-4. The results of the DEHL break are shown in Figures 6.5-5 through 6.5-6. Tables 6.5-31 through 6.5-33 provide detailed results for the analyses.

6.5.3.5.1 DEPS Break with Minimum ECCS

This analysis assumes a loss-of-offsite power (LOOP) in coincidence with a DEPS rupture. The associated single-failure assumption is the failure of a diesel to start, resulting in one train of ECCS and containment safeguards equipment being available. This combination results in a minimum set of safeguards equipment being available. Furthermore, LOOP delays the actuation times of the safeguards equipment due to the time required for diesel startup after receiving the SI signal.

The postulated RCS break results in a rapid release of M&E to the containment with a resulting rapid rise in the containment pressure and temperature. This rapid rise in containment pressure results in the generation of a fan cooler initiation signal at 1 second, and a containment spray initiation signal at 8 seconds. The containment pressure continues to rise rapidly in response to the release of M&E, reaching the peak blowdown pressure of 38.9 psig at 24 seconds, and then decreasing slightly as the end of blowdown occurs at 27.2 seconds (pressure = 38.5 psig). The end of blowdown marks a time when the initial inventory in the RCS has been exhausted and a slow process of filling the RCS downcomer in preparation for reflood has begun. During the reflood period, the RCFCs start at approximately 49 seconds. Since the M&E release during this period is low and the RCFCs are removing heat, the pressure decreases slightly to 36.1 psig at approximately 67 seconds, the time at which the intact loop accumulators have emptied. The pressure then starts to slowly rise in response to the loss of steam condensation in the RCS loops and the introduction of the accumulator nitrogen gas to the containment.

CS initiation occurs at approximately 68 seconds. Reflood continues at a reduced flooding rate due to the buildup of mass in the RCS core, which offsets the downcomer head. This reduction in flooding rate and the continued action of the RCFCs and CS leads to a slowly decreasing

pressure as the end of reflood is reached at 182.1 seconds. At this time in the transient simulation, by design of the WCAP-10325-P-A (Reference 1) model, energy removal is initiated from the steam generator secondary side at a very increased rate, resulting in a rise in containment pressure from 182.1 seconds until sufficient energy has been removed from the steam generators to bring the intact loops' steam generator secondary pressure down to 20 psi below the containment design pressure of 47 psig. The steam generator secondary energy release results in a peak containment pressure of 42.00 psig at 1118 seconds. After this peak is reached, the M&E release is reduced since the large energy removal from the steam generators has been accomplished.

Containment pressure slowly decreases until the cold leg recirculation time is reached at 1623.8 seconds. After the RHRS is realigned for cold leg recirculation, an increase in the SI temperature (due to water delivery from the hot sump and reduction in steam condensation) results in an increase in containment pressure. Containment spray is terminated at 3355 seconds. By 3600 seconds, the steam generator secondary energy has been reduced to a low value and the containment pressure begins a steady decline. This trend continues until the end of the transient at 10^7 seconds (approximately 115 days).

6.5.3.5.2 DEPS Break with Maximum ECCS

The DEPS break with maximum ECCS has a transient history similar to the minimum ECCS case discussed in subsection 6.5.3.5.1 of this report. Table 6.5-27 provides the key sequence of events and Table 6.5-34 shows that a peak pressure of 38.94 psig was calculated at 23.7 seconds.

6.5.3.5.3 DEHL Break

This analysis assumes a LOOP in coincidence with a DEHL rupture. The associated single failure assumption is the component failure of one CS pump. Furthermore, LOOP delays the actuation times of the safeguards equipment due to the time required for diesel startup after receipt of the SI signal.

The postulated RCS break results in a rapid release of M&E to the containment with a resulting rapid rise in both the containment pressure and temperature. This rapid rise in containment pressure results in the generation of a fan cooler initiation signal at 1 second and a containment spray initiation signal at 8 seconds. The containment pressure continues to rise rapidly in response to the release of M&E, reaching the peak blowdown pressure of 40.38 psig at 24.2 seconds and then decreasing slightly as the end of blowdown occurs at 25.6 seconds. The end of blowdown marks a time when the initial inventory in the RCS has been exhausted, and the process of filling the RCS downcomer in preparation for reflood has begun. Since the

reflood for a hot leg break is very fast due to the low resistance to steam venting posed by the broken hot leg, Westinghouse terminates hot leg break M&E release transients at the end of blowdown. The basis for this is further developed in References 1 and 7.

6.5.3.6 Conclusions

LOCA containment response analyses have been performed as part of the IP3 SPU. The analyses included long-term pressure and temperature profiles for the DEPS minimum and maximum ECCS flow cases. As illustrated in Table 6.5-34, the analyzed design cases resulted in a peak containment pressure that was less than the containment design pressure of 47 psig and less than the ILRT limit of 42.42 psig. The long-term pressures are well below 50 percent of the peak value within 24 hours. Based on these results, the applicable LOCA criteria for IP3 have been met. Thus, all typical design accident (that is, NUREG-0800) and IP3 UFSAR analysis criteria have been met at SPU conditions.

6.5.4 References

1. WCAP-10325-P-A (Proprietary) and WCAP-10326-A (Nonproprietary), *Westinghouse LOCA Mass and Energy Release Model for Containment Design,March 1979 Version,* March 1983.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report,* Docket No. 50-286, Rev. 10, January 6, 2001.

3. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

4. 10CFR50, Appendix K, *ECCS Evaluation Models.*

5. Amendment No. 126, *Facility Operating License No. DPR-58 (TAC No. 7106), for D. C. Cook Nuclear Plant Unit 1,* Docket No. 50-315, June 9, 1989.

6. EPRI 294-2, *Mixing of Emergency Core Cooling Water with Steam; 1/3-Scale Test and Summary,* (WCAP-8423), Final Report, June 1975.

7. WCAP-8264-P-A (Proprietary) and WCAP-8312-A (Non-proprietary), *Topical Report Westinghouse Mass and Energy Release Data For Containment Design,* Rev. 1, August 1975.

8. ANSI/ANS-5.1-1979, *American National Standard for Decay Heat Power in Light Water Reactors,* The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, August 1979.

9. *NRC Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Elimination of Large Primary Loop Ruptures as a Design Basis, Power Authority of the State of New York, Indian Point Nuclear Generating Unit No. 3,* Docket No. 50-286, March 10, 1986.

10. WCAP-8327 (Proprietary) and WCAP-8326 (Nonproprietary), *Containment Pressure Analysis Code (COCO),* July 1974.

11. *Interim Report on Safety Assessments and Facilities Establishment Project in Japan for Period Ending June 1965,* No. 1, Takashi Tagami.

12. *Chemical Engineering Progress, 48,* "Evaporation for Drops," pp.141-146, D. W. Ranz and W. R. Marshall, Jr., March 1952.

13. ORNL-TM-2412 Part VI, *Design Consideration of Reactor Containment Spray System. Part VI, The Heating of Spray Drops in Air-Steam Atmospheres,* L. F. Parsly, January 1970.

Table 6.5-1 System Parameters Initial Conditions for IP3 SPU	
	Value
Parameters	**SPU**
Core Thermal Power Without Uncertainty (MWt)	3216
RCS Total Flow Rate (lbm/sec)	37,444.4
Vessel Outlet Temperature With Uncertainty (°F)	610.5
Core Inlet Temperature With Uncertainty (°F)	548.5
Vessel Average Temperature Without Uncertainty (°F)	572.0
Initial Steam Generator Steam Pressure (psia)	787.0
SGTP (%)	0
Initial Steam Generator Secondary Side Mass (lbm)	100,668.7
Assumed Maximum Containment Backpressure (psia)	61.7
Accumulator Water Volume Per Accumulator Including Line Volume (ft^3) N_2 Cover Gas Pressure (psia) Temperature (°F)	 807.2 555 130
Total SI Delay From Beginning of Event (sec)	27.8

Table 6.5-2

SI Flow Rate
Minimum ECCS for IP3 SPU

RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (reflood phase)	
14.7	5252.3
24.7	5115.1
34.7	4975.2
44.7	4832.7
54.7	4687.2
64.7	4536.1
74.7	4367.1
84.7	4192.8
94.7	4012.4
104.7	3825.0
114.7	3630.0
Injection Mode (post-reflood phase)	
61.7	4581.4
Cold Leg Recirculation Mode	
61.7	2080
Hot Leg Recirculation Mode	
61.7	717

Table 6.5-3 SI Flow Rate Maximum ECCS for IP3 SPU	
RCS Pressure (psia)	Total Flow (gpm)
Injection Mode (reflood phase)	
14.7	7815.6
34.7	7479.7
54.7	7129.7
74.7	6745.8
94.7	6330.8
114.7	5885.9
134.7	5403.6
154.7	4866.3
174.7	4215.0
194.7	3414.7
214.7	2180.4
234.7	1332.7
314.7	1290.1
414.7	1234.6
Injection Mode (post-reflood phase)	
61.7	6995.3
Cold Leg Recirculation Mode	
61.7	4160

Table 6.5-4 DEHL Break Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.001	43,216.1	27,017.6	43,213.1	27,014.4
0.002	44,433.6	27,779.4	44,164.6	27,604.0
0.1	45,538.9	28,778.8	25,444.9	15,873.6
0.2	32,791.7	21,154.0	22,595.2	14,017.6
0.3	32,084.8	20,646.9	20,305.9	12,441.9
0.4	31,280.4	20,117.6	19,120.5	11,538.7
0.5	31,012.0	19,936.5	18,348.2	10,908.8
0.6	30,970.6	19,912.6	17,786.9	10,431.7
0.7	30,879.0	19,877.0	17,343.9	10,051.4
0.8	30,588.4	19,730.6	17,023.3	9762.1
0.9	30,227.7	19,552.0	16,732.0	9505.9
1.0	29,827.8	19,360.2	16,560.6	9329.1
1.1	29,559.7	19,264.0	16,444.0	9194.1
1.2	29,306.8	19,187.0	16,442.2	9130.6
1.3	29,048.7	19,106.1	16,506.8	9108.9
1.4	28,718.0	18,974.1	16,618.7	9118.1
1.5	28,330.4	18,796.2	16,751.8	9144.7
1.6	27,926.6	18,603.7	16,900.6	9184.9
1.7	27,555.8	18,429.8	17,051.8	9232.4
1.8	27,184.5	18,255.6	17,199.2	9282.7
1.9	26,773.1	18,050.8	17,332.3	9330.3
2.0	26,314.9	17,808.3	17,447.9	9372.9
2.1	25,851.9	17,556.4	17,543.1	9408.5
2.2	25,391.2	17,303.5	17,619.5	9437.1
2.3	24,938.1	17,054.4	17,679.3	9459.3
2.4	24,496.9	16,809.6	17,722.1	9474.5
2.5	24,046.1	16,552.9	17,750.4	9483.7
2.6	23,573.2	16,273.0	17,766.3	9487.6
2.7	23,114.2	15,997.0	17,771.4	9486.7
2.8	22,689.1	15,743.8	17,768.4	9482.3
2.9	22,284.5	15,500.2	17,756.4	9473.7
3.0	21,875.4	15,243.8	17,734.3	9460.2
3.1	21,492.2	15,000.3	17,702.9	9442.1
3.2	21,129.3	14,765.0	17,663.7	9420.1
3.3	20,779.2	14,529.5	17,615.8	9393.8
3.4	20,470.4	14,319.2	17,561.3	9364.3
3.5	20,180.8	14,117.6	17,501.0	9331.9
3.6	19,903.1	13,914.9	17,434.1	9296.3

Table 6.5-4 (Cont.) DEHL Break Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.7	19,644.4	13,720.7	17,361.0	9257.8
3.8	19,414.0	13,544.5	17,283.1	9216.9
3.9	19,194.4	13,368.4	17,199.0	9173.1
4.0	19,004.3	13,209.8	17,109.4	9126.7
4.2	18,688.3	12,931.8	16,914.7	9026.8
4.4	18,436.2	12,689.9	16,696.0	8916.1
4.6	18,246.3	12,490.3	16,458.1	8797.2
4.8	18,184.6	12,385.8	16,197.0	8668.2
5.0	18,242.3	12,349.7	15,914.4	8530.2
5.2	18,416.6	12,359.7	15,630.4	8393.8
5.4	18,634.4	12,390.6	15,313.5	8240.9
5.6	18,872.2	12,431.3	14,943.5	8059.9
5.8	19,167.6	12,503.3	14,553.8	7868.7
6.0	19,546.1	12,605.6	14,202.2	7697.4
6.2	11,596.1	9053.2	13,865.2	7532.8
6.4	14,615.2	10,424.6	13,543.6	7374.6
6.6	14,498.6	10,297.0	13,191.7	7197.4
6.8	14,631.6	10,261.7	12,824.2	7009.7
7.0	14,823.9	10,328.0	12,479.4	6833.2
7.2	15,043.6	10,422.7	12,161.2	6669.8
7.4	15,250.0	10,436.2	11,845.6	6506.1
7.6	15,449.4	10,476.1	11,532.8	6342.4
7.8	15,635.7	10,580.4	11,228.3	6182.3
8.0	15,575.1	10,451.1	10,941.3	6031.2
8.2	15,901.5	10,556.6	10,677.6	5892.1
8.4	16,217.3	10,658.8	10,419.5	5755.5
8.6	16,550.9	10,772.6	10,167.7	5621.8
8.8	16,971.8	10,933.5	9920.2	5490.0
9.0	17,728.7	11,275.9	9678.6	5361.3
9.2	18,541.3	11,698.2	9442.1	5235.5
9.4	18,929.1	11,866.3	9206.6	5110.3
9.6	19,223.8	11,965.3	8971.5	4985.4
9.8	18,854.0	11,651.4	8726.2	4855.0
10.0	17,951.0	11,023.8	8481.1	4725.3
10.2	14,860.8	9376.5	8233.4	4595.0
10.2	14,840.4	9366.2	8231.4	4594.0
10.4	14,303.8	9059.4	8004.6	4475.3
10.6	14,418.5	9086.4	7784.8	4361.1
10.8	14,561.4	9141.4	7592.6	4262.5

Table 6.5-4 (Cont.) DEHL Break Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
11.0	14,722.8	9210.1	7417.9	4172.7
11.2	14,873.7	9265.9	7245.6	4083.2
11.4	15,060.7	9333.2	7079.6	3997.0
11.6	15,358.1	9452.3	6918.4	3913.3
11.8	15,822.0	9672.5	6752.4	3827.3
12.0	15,709.9	9570.8	6587.3	3742.1
12.2	15,462.5	9384.3	6419.7	3656.1
12.4	14,575.9	8878.8	6246.4	3567.5
12.6	12,813.6	7956.4	6076.2	3481.5
12.8	12,586.2	7813.6	5909.8	3398.4
13.0	12,574.0	7785.1	5753.6	3321.3
13.2	12,565.4	7764.9	5614.8	3253.7
13.4	12,544.7	7740.0	5481.0	3188.0
13.6	12,502.3	7704.5	5356.4	3126.3
13.8	12,413.7	7644.8	5235.4	3066.3
14.0	12,248.4	7546.3	5115.8	3007.0
14.2	11,967.8	7389.8	4998.4	2949.2
14.4	11,490.4	7165.4	4884.3	2893.4
14.6	10,863.9	6930.2	4767.2	2836.4
14.8	10,495.2	6789.9	4653.9	2781.9
15.0	10,225.7	6678.1	4544.9	2729.6
15.2	9956.4	6553.4	4433.8	2676.3
15.4	9643.3	6398.4	4323.8	2623.7
15.6	9288.3	6219.5	4213.7	2571.5
15.8	8937.9	6045.4	4099.8	2517.7
16.0	8619.6	5891.9	3979.2	2461.0
16.2	8322.4	5755.6	3846.8	2399.1
16.4	8019.5	5624.2	3698.2	2330.8
16.6	7695.6	5489.8	3534.0	2256.5
16.8	7342.7	5348.1	3358.3	2177.1
17.0	6962.8	5199.8	3179.0	2094.7
17.2	6557.4	5045.0	3004.6	2012.0
17.4	6136.6	4886.9	2844.0	1932.3
17.6	5701.0	4725.1	2700.7	1857.7
17.8	5260.7	4562.3	2576.3	1789.8
18.0	4822.8	4398.4	2470.4	1729.7
18.2	4368.6	4198.7	2379.7	1677.0
18.4	3966.3	3932.9	2297.4	1628.2
18.6	3702.8	3715.2	2224.0	1584.6

Table 6.5-4 (Cont.)

DEHL Break

Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
18.8	3502.0	3553.9	2156.6	1544.8
19.0	3337.0	3431.7	2092.0	1508.1
19.2	3175.6	3312.9	2028.2	1473.8
19.4	3006.4	3193.8	1964.2	1441.4
19.6	2833.6	3074.0	1899.5	1410.3
19.8	2659.6	2943.8	1832.2	1378.9
20.0	2476.5	2810.7	1765.5	1348.9
20.2	2279.9	2650.6	1697.5	1319.2
20.4	2105.3	2493.7	1626.0	1289.3
20.6	1969.1	2360.6	1546.6	1258.6
20.8	1835.2	2217.8	1461.5	1230.8
21.0	1703.9	2071.2	1370.8	1202.4
21.2	1582.3	1933.8	1282.9	1171.9
21.4	1471.4	1809.0	1209.5	1142.4
21.6	1373.0	1697.9	1151.9	1116.0
21.8	1298.2	1615.2	1107.2	1095.8
22.0	1257.9	1571.0	1068.6	1074.2
22.2	1194.9	1500.0	1040.6	1054.5
22.4	1119.7	1408.8	1019.6	1036.8
22.6	1047.1	1319.4	1004.2	1019.2
22.8	976.8	1232.5	995.6	1003.8
23.0	928.8	1170.9	988.5	990.1
23.2	860.1	1086.8	975.4	980.3
23.4	770.3	973.1	938.3	975.2
23.6	704.9	893.0	853.3	973.8
23.8	641.7	813.7	661.6	802.7
24.0	588.2	746.7	574.4	703.1
24.2	548.1	696.1	579.4	709.1
24.4	518.7	658.7	512.3	627.2
24.6	500.9	636.1	371.8	456.9
24.8	487.5	618.7	319.8	394.3
25.0	475.6	603.1	247.6	305.8
25.2	54.2	69.9	199.2	247.1
25.4	0.0	0.0	95.2	118.9
25.6	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting from the reactor-vessel side of the break
2. M&E exiting from the steam-generator side of the break

Table 6.5-5

DEHL Break Mass Balance for IP3 SPU

Time (sec)		0.00	25.60	25.60
		Mass (thousand lbm)		
Initial	In RCS and accumulators	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00
	Total added	0.00	0.00	0.00
Total Available		732.01	732.01	732.01
Distribution	Reactor coolant	527.21	61.26	88.21
	Accumulator	204.80	158.37	131.42
	Total contents	732.01	219.63	219.63
Effluent	Break flow	0.00	512.36	512.36
	ECCS spill	0.00	0.00	0.00
	Total effluent	0.00	512.36	512.36
Total Accountable		732.01	731.98	731.98

Table 6.5-6 DEHL Break Energy Balance for IP3 SPU				
Time (sec)		0.00	25.60	25.60
		Energy (million Btu)		
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00
	Decay heat	0.00	7.72	7.72
	Heat from secondary	0.00	9.96	9.96
	Total added	0.00	17.68	17.68
Total Available		775.34	793.02	793.02
Distribution	Reactor coolant	305.75	15.57	18.25
	Accumulator	20.35	15.73	13.06
	Core stored	26.87	10.59	10.59
	Primary metal	166.23	156.28	156.28
	Secondary metal	40.98	40.06	40.06
	Steam generator	215.15	227.53	227.53
	Total contents	775.34	465.77	465.77
Effluent	Break flow	0.00	326.77	326.77
	ECCS spill	0.00	0.00	0.00
	Total effluent	0.00	326.77	326.77
Total Accountable		775.34	792.53	792.53

Table 6.5-7

DEPS Break Minimum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.001	81,761.8	44,233.2	40,576.0	21,912.8
0.1	40,368.4	21,885.1	19,793.9	10,677.7
0.2	45,306.7	24,772.6	22,451.3	12,124.9
0.3	45,415.9	25,096.5	23,512.5	12,704.7
0.4	45,055.9	25,215.1	23,517.2	12,711.4
0.5	44,009.1	24,945.6	22,969.5	12,420.5
0.6	44,256.3	25,378.4	22,403.5	12,120.2
0.7	43,600.3	25,252.0	22,049.2	11,934.2
0.8	42,230.5	24,671.9	21,887.5	11,851.0
0.9	40,998.0	24,158.5	21,772.1	11,792.1
1.0	39,954.5	23,761.7	21,676.2	11,742.9
1.1	38,791.7	23,329.2	21,567.5	11,686.1
1.2	37,322.5	22,738.0	21,464.4	11,631.9
1.3	35,681.4	22,020.7	21,381.4	11,588.1
1.4	34,261.3	21,372.7	21,325.8	11,558.9
1.5	33,185.6	20,878.9	21,311.8	11,552.2
1.6	32,347.7	20,502.1	21,335.1	11,565.8
1.7	31,543.5	20,137.7	21,256.7	11,523.4
1.8	30,691.4	19,737.1	21,078.4	11,426.5
1.9	29,771.4	19,286.1	20,897.8	11,328.4
2.0	28,806.8	18,796.0	20,735.0	11,240.3
2.1	27,794.9	18,268.3	20,582.8	11,158.0
2.2	26,813.6	17,759.7	20,406.0	11,062.5
2.3	25,407.1	16,959.1	20,198.9	10,950.3
2.4	23,314.1	15,671.6	19,979.5	10,831.5
2.5	21,428.3	14,504.8	19,781.6	10,724.5
2.6	21,061.3	14,354.1	19,588.9	10,620.6
2.7	20,375.5	13,940.6	19,405.6	10,521.9
2.8	19,647.9	13,490.3	19,200.4	10,411.3
2.9	19,327.9	13,315.2	19,003.6	10,305.3
3.0	18,990.9	13,110.6	18,809.5	10,201.0
3.1	18,936.7	13,103.3	18,599.8	10,088.1
3.2	18,708.8	12,965.8	18,359.2	9958.3
3.3	18,376.1	12,765.8	18,107.3	9822.4
3.4	18,036.8	12,557.7	17,873.1	9696.2

Table 6.5-7 (Cont.) DEPS Break Minimum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[1]		Break Path No. 2[2]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.5	17,593.9	12,267.4	17,641.1	9571.4
3.6	17,069.3	11,917.1	17,408.8	9446.3
3.7	16,489.9	11,528.9	17,177.4	9321.8
3.8	15,903.3	11,135.1	16,954.4	9202.0
3.9	15,363.2	10,772.2	16,746.0	9090.1
4.0	14,881.1	10,447.4	16,551.1	8985.8
4.2	14,051.8	9886.3	16,181.4	8787.9
4.4	13,368.7	9425.1	15,844.1	8607.7
4.6	12,849.6	9066.2	15,533.4	8442.0
4.8	12,412.2	8757.6	15,247.7	8289.7
5.0	12,013.1	8465.4	14,999.3	8157.8
5.2	11,703.6	8224.2	14,763.6	8032.5
5.4	11,586.3	8094.8	14,554.2	7921.5
5.6	11,514.6	7994.2	14,351.2	7813.7
5.8	11,482.1	7922.8	14,628.1	7971.2
6.0	11,522.2	7898.5	14,747.6	8037.3
6.2	12,194.7	8296.4	14,583.2	7949.9
6.4	12,141.3	8354.3	14,758.0	8049.7
6.6	10,307.9	7832.3	14,611.9	7971.5
6.8	9121.4	7303.9	14,448.4	7884.8
7.0	9073.9	7243.1	14,317.3	7815.8
7.2	9131.3	7217.0	14,150.0	7726.8
7.4	9251.8	7207.9	13,997.8	7646.3
7.6	9481.4	7234.9	13,888.3	7588.7
7.8	9840.4	7325.9	13,772.0	7525.2
8.0	10,359.8	7518.4	13,588.0	7423.3
8.2	11,037.7	7812.7	13,409.2	7324.2
8.4	11,803.6	8167.7	13,241.4	7231.2
8.6	12,593.0	8547.8	13,064.4	7133.0
8.8	13,245.7	8851.5	12,873.9	7027.5
9.0	13,483.0	8908.3	12,687.9	6924.7
9.2	13,276.1	8712.1	12,523.4	6834.0
9.4	12,965.9	8476.1	12,374.3	6751.5
9.6	12,574.6	8194.2	12,222.6	6667.2
9.8	11,645.6	7582.1	12,081.1	6588.6
10.0	10,593.6	6936.8	12,004.7	6546.0

Table 6.5-7 (Cont.)

DEPS Break Minimum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10.2	10,208.2	6743.1	11,946.2	6512.7
10.4	9933.1	6606.9	11,771.6	6414.9
10.6	9558.0	6412.6	11,662.9	6354.9
10.8	9363.2	6333.5	11,584.3	6312.0
11.0	9110.8	6193.7	11,405.8	6213.9
11.2	8843.7	6050.6	11,321.2	6168.3
11.4	8611.3	5935.8	11,207.4	6105.7
11.6	8331.5	5791.9	11,060.1	6024.8
11.8	8094.4	5682.6	10,972.5	5976.9
12.0	7841.1	5558.8	10,793.8	5878.6
12.2	7631.1	5453.0	10,669.0	5810.9
12.4	7447.7	5345.9	10,550.1	5746.4
12.6	7300.3	5249.1	10,397.4	5663.0
12.8	7176.9	5155.0	10,272.0	5594.7
13.0	7066.5	5061.5	10,136.2	5520.5
13.2	6964.1	4969.2	10,003.1	5447.9
13.4	6860.9	4873.9	9867.7	5374.1
13.6	6756.5	4776.9	9730.9	5299.6
13.8	6652.7	4679.5	9599.0	5227.9
14.0	6551.1	4582.4	9463.3	5154.1
14.2	6454.6	4487.7	9332.5	5083.2
14.4	6364.5	4396.4	9204.0	5013.5
14.6	6286.8	4312.4	9088.1	4950.7
14.8	6229.3	4241.5	8991.4	4898.8
15.0	6169.6	4171.4	8866.3	4830.2
15.2	6106.1	4106.5	8779.1	4783.6
15.4	6042.3	4043.3	8675.6	4727.6
15.6	5976.8	3981.7	8590.2	4682.1
15.8	5911.6	3925.6	8496.0	4631.6
16.0	5840.4	3870.9	8414.4	4588.8
16.2	5773.5	3823.7	8339.7	4550.2
16.4	5698.8	3775.3	8193.0	4472.2
16.6	5626.7	3739.9	8057.1	4403.0
16.8	5544.7	3720.5	7908.6	4327.8
17.0	5421.2	3692.9	7741.4	4242.5
17.2	5275.7	3658.2	7585.2	4161.0
17.4	5130.3	3623.8	7425.0	4062.6

Table 6.5-7 (Cont.)

DEPS Break Minimum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
17.6	4987.5	3591.5	7279.3	3956.0
17.8	4848.1	3560.2	7149.2	3845.8
18.0	4712.0	3529.8	7046.1	3743.0
18.2	4578.9	3500.4	6951.5	3642.4
18.4	4447.5	3473.6	6860.8	3545.2
18.6	4317.2	3448.0	6736.5	3434.4
18.8	4184.1	3423.5	6572.9	3308.7
19.0	4049.4	3401.2	6399.0	3183.7
19.2	3911.0	3380.1	6214.5	3060.8
19.4	3769.8	3361.2	6034.1	2949.3
19.6	3623.5	3344.6	5864.7	2853.8
19.8	3472.5	3330.4	5695.8	2768.6
20.0	3285.7	3291.4	5492.9	2673.1
20.2	3023.0	3191.9	5043.3	2439.6
20.4	2764.3	3072.7	4849.5	2304.6
20.6	2543.6	2957.3	4656.1	2205.9
20.8	2393.5	2873.4	4365.2	2058.6
21.0	2180.7	2661.6	4194.5	1968.7
21.2	2028.5	2492.3	3842.0	1786.4
21.4	1885.9	2325.5	3636.1	1644.4
21.6	1764.8	2182.2	3508.4	1551.5
21.8	1659.9	2056.6	3113.1	1339.6
22.0	1549.0	1922.8	2768.0	1141.4
22.2	1453.0	1806.5	2485.3	983.1
22.4	1366.4	1701.7	2269.9	866.9
22.6	1282.0	1598.2	2098.7	777.9
22.8	1194.9	1492.1	2020.9	728.2
23.0	1119.7	1399.9	2062.5	723.2
23.2	1045.0	1307.9	2203.1	754.1
23.4	958.1	1200.9	2404.8	807.2
23.6	868.4	1089.6	2598.9	859.2
23.8	786.1	987.3	2745.0	896.0
24.0	701.2	881.4	2904.0	935.2
24.2	614.4	772.9	3064.9	971.6
24.4	528.0	664.7	3199.8	997.3
24.6	446.8	562.9	3189.0	977.5
24.8	370.2	466.8	2986.6	903.0

Table 6.5-7 (Cont.) DEPS Break Minimum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
25.0	301.9	380.8	2789.6	834.7
25.2	239.4	302.3	2590.3	768.5
25.4	183.9	232.4	2383.7	702.3
25.6	142.6	180.4	2177.3	637.8
25.8	127.2	161.1	1969.4	574.5
26.0	105.9	134.2	1761.3	512.4
26.2	58.4	74.2	1556.4	452.4
26.4	0.0	0.0	1339.4	389.5
26.6	0.0	0.0	1082.8	315.5
26.8	0.0	0.0	724.1	211.6
27.0	0.0	0.0	25.5	7.5
27.2	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-8

DEPS Break Maximum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
0.0	0.0	0.0	0.0	0.0
0.0	81,761.8	44,233.2	40,576.0	21,912.8
0.1	40,368.4	21,885.1	19,793.9	10,677.7
0.2	45,306.7	24,772.6	22,451.3	12,124.9
0.3	45,415.9	25,096.5	23,512.5	12,704.7
0.4	45,055.9	25,215.1	23,517.2	12,711.4
0.5	44,009.1	24,945.6	22,969.5	12,420.5
0.6	44,256.3	25,378.4	22,403.5	12,120.2
0.7	43,600.3	25,252.0	22,049.2	11,934.2
0.8	42,230.5	24,671.9	21,887.5	11,851.0
0.9	40,998.0	24,158.5	21,772.1	11,792.1
1.0	39,954.5	23,761.7	21,676.2	11,742.9
1.1	38,791.7	23,329.2	21,567.5	11,686.1
1.2	37,322.5	22,738.0	21,464.4	11,631.9
1.3	35,681.4	22,020.7	21,381.4	11,588.1
1.4	34,261.3	21,372.7	21,325.8	11,558.9
1.5	33,185.6	20,878.9	21,311.8	11,552.2
1.6	32,347.7	20,502.1	21,335.1	11,565.8
1.7	31,543.5	20,137.7	21,256.7	11,523.4
1.8	30,691.4	19,737.1	21,078.4	11,426.5
1.9	29,771.4	19,286.1	20,897.8	11,328.4
2.0	28,806.8	18,796.0	20,735.0	11,240.3
2.1	27,794.9	18,268.3	20,582.8	11,158.0
2.2	26,813.6	17,759.7	20,406.0	11,062.5
2.3	25,407.1	16,959.1	20,198.9	10,950.3
2.4	23,314.1	15,671.6	19,979.5	10,831.5
2.5	21,428.3	14,504.8	19,781.6	10,724.5
2.6	21,061.3	14,354.1	19,588.9	10,620.6
2.7	20,375.5	13,940.6	19,405.6	10,521.9
2.8	19,647.9	13,490.3	19,200.4	10,411.3
2.9	19,327.9	13,315.2	19,003.6	10,305.3
3.0	18,990.9	13,110.6	18,809.5	10,201.0
3.1	18,936.7	13,103.3	18,599.8	10,088.1
3.2	18,708.8	12,965.8	18,359.2	9958.3
3.3	18,376.1	12,765.8	18,107.3	9822.4
3.4	18,036.8	12,557.7	17,873.1	9696.2

Table 6.5-8 (Cont.)

DEPS Break Maximum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
3.5	17,593.9	12,267.4	17,641.1	9571.4
3.6	17,069.3	11,917.1	17,408.8	9446.3
3.7	16,489.9	11,528.9	17,177.4	9321.8
3.8	15,903.3	11,135.1	16,954.4	9202.0
3.9	15,363.2	10,772.2	16,746.0	9090.1
4.0	14,881.1	10,447.4	16,551.1	8985.8
4.2	14,051.8	9886.3	16,181.4	8787.9
4.4	13,368.7	9425.1	15,844.1	8607.7
4.6	12,849.6	9066.2	15,533.4	8442.0
4.8	12,412.2	8757.6	15,247.7	8289.7
5.0	12,013.1	8465.4	14,999.3	8157.8
5.2	11,703.6	8224.2	14,763.6	8032.5
5.4	11,586.3	8094.8	14,554.2	7921.5
5.6	11,514.6	7994.2	14,351.2	7813.7
5.8	11,482.1	7922.8	14,628.1	7971.2
6.0	11,522.2	7898.5	14,747.6	8037.3
6.2	12,194.7	8296.4	14,583.2	7949.9
6.4	12,141.3	8354.3	14,758.0	8049.7
6.6	10,307.9	7832.3	14,611.9	7971.5
6.8	9121.4	7303.9	14,448.4	7884.8
7.0	9073.9	7243.1	14,317.3	7815.8
7.2	9131.3	7217.0	14,150.0	7726.8
7.4	9251.8	7207.9	13,997.8	7646.3
7.6	9481.4	7234.9	13,888.3	7588.7
7.8	9840.4	7325.9	13,772.0	7525.2
8.0	10359.8	7518.4	13,588.0	7423.3
8.2	11037.7	7812.7	13,409.2	7324.2
8.4	11803.6	8167.7	13,241.4	7231.2
8.6	12593.0	8547.8	13,064.4	7133.0
8.8	13245.7	8851.5	12,873.9	7027.5
9.0	13483.0	8908.3	12,687.9	6924.7
9.2	13276.1	8712.1	12,523.4	6834.0
9.4	12965.9	8476.1	12,374.3	6751.5
9.6	12574.6	8194.2	12,222.6	6667.2
9.8	11645.6	7582.1	12,081.1	6588.6
10.0	10593.6	6936.8	12,004.7	6546.0

Table 6.5-8 (Cont.)

DEPS Break Maximum ECCS
Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10.2	10208.2	6743.1	11,946.2	6512.7
10.4	9933.1	6606.9	11,771.6	6414.9
10.6	9558.0	6412.6	11,662.9	6354.9
10.8	9363.2	6333.5	11,584.3	6312.0
11.0	9110.8	6193.7	11,405.8	6213.9
11.2	8843.7	6050.6	11,321.2	6168.3
11.4	8611.3	5935.8	11,207.4	6105.7
11.6	8331.5	5791.9	11,060.1	6024.8
11.8	8094.4	5682.6	10,972.5	5976.9
12.0	7841.1	5558.8	10,793.8	5878.6
12.2	7631.1	5453.0	10,669.0	5810.9
12.4	7447.7	5345.9	10,550.1	5746.4
12.6	7300.3	5249.1	10,397.4	5663.0
12.8	7176.9	5155.0	10,272.0	5594.7
13.0	7066.5	5061.5	10,136.2	5520.5
13.2	6964.1	4969.2	10,003.1	5447.9
13.4	6860.9	4873.9	9867.7	5374.1
13.6	6756.5	4776.9	9730.9	5299.6
13.8	6652.7	4679.5	9599.0	5227.9
14.0	6551.1	4582.4	9463.3	5154.1
14.2	6454.6	4487.7	9332.5	5083.2
14.4	6364.5	4396.4	9204.0	5013.5
14.6	6286.8	4312.4	9088.1	4950.7
14.8	6229.3	4241.5	8991.4	4898.8
15.0	6169.6	4171.4	8866.3	4830.2
15.2	6106.1	4106.5	8779.1	4783.6
15.4	6042.3	4043.3	8675.6	4727.6
15.6	5976.8	3981.7	8590.2	4682.1
15.8	5911.6	3925.6	8496.0	4631.6
16.0	5840.4	3870.9	8414.4	4588.8
16.2	5773.5	3823.7	8339.7	4550.2
16.4	5698.8	3775.3	8193.0	4472.2
16.6	5626.7	3739.9	8057.1	4403.0
16.8	5544.7	3720.5	7908.6	4327.8
17.0	5421.2	3692.9	7741.4	4242.5
17.2	5275.7	3658.2	7585.2	4161.0
17.4	5130.3	3623.8	7425.0	4062.6

Table 6.5-8 (Cont.) DEPS Break Maximum ECCS Blowdown M&E Releases for IP3 SPU				
	Break Path No. 1(1)		Break Path No. 2(2)	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
17.6	4987.5	3591.5	7279.3	3956.0
17.8	4848.1	3560.2	7149.2	3845.8
18.0	4712.0	3529.8	7046.1	3743.0
18.2	4578.9	3500.4	6951.5	3642.4
18.4	4447.5	3473.6	6860.8	3545.2
18.6	4317.2	3448.0	6736.5	3434.4
18.8	4184.1	3423.5	6572.9	3308.7
19.0	4049.4	3401.2	6399.0	3183.7
19.2	3911.0	3380.1	6214.5	3060.8
19.4	3769.8	3361.2	6034.1	2949.3
19.6	3623.5	3344.6	5864.7	2853.8
19.8	3472.5	3330.4	5695.8	2768.6
20.0	3285.7	3291.4	5492.9	2673.1
20.2	3023.0	3191.9	5043.3	2439.6
20.4	2764.3	3072.7	4849.5	2304.6
20.6	2543.6	2957.3	4656.1	2205.9
20.8	2393.5	2873.4	4365.2	2058.6
21.0	2180.7	2661.6	4194.5	1968.7
21.2	2028.5	2492.3	3842.0	1786.4
21.4	1885.9	2325.5	3636.1	1644.4
21.6	1764.8	2182.2	3508.4	1551.5
21.8	1659.9	2056.6	3113.1	1339.6
22.0	1549.0	1922.8	2768.0	1141.4
22.2	1453.0	1806.5	2485.3	983.1
22.4	1366.4	1701.7	2269.9	866.9
22.6	1282.0	1598.2	2098.7	777.9
22.8	1194.9	1492.1	2020.9	728.2
23.0	1119.7	1399.9	2062.5	723.2
23.2	1045.0	1307.9	2203.1	754.1
23.4	958.1	1200.9	2404.8	807.2
23.6	868.4	1089.6	2598.9	859.2
23.8	786.1	987.3	2745.0	896.0
24.0	701.2	881.4	2904.0	935.2
24.2	614.4	772.9	3064.9	971.6
24.4	528.0	664.7	3199.8	997.3
24.6	446.8	562.9	3189.0	977.5
24.8	370.2	466.8	2986.6	903.0

Table 6.5-8 (Cont.)

DEPS Break Maximum ECCS Blowdown M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
25.0	301.9	380.8	2789.6	834.7
25.2	239.4	302.3	2590.3	768.5
25.4	183.9	232.4	2383.7	702.3
25.6	142.6	180.4	2177.3	637.8
25.8	127.2	161.1	1969.4	574.5
26.0	105.9	134.2	1761.3	512.4
26.2	58.4	74.2	1556.4	452.4
26.4	0.0	0.0	1339.4	389.5
26.6	0.0	0.0	1082.8	315.5
26.8	0.0	0.0	724.1	211.6
27.0	0.0	0.0	25.5	7.5
27.2	0.0	0.0	0.0	0.0

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-9

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
27.2	0.0	0.0	0.0	0.0
27.8	0.0	0.0	0.0	0.0
27.9	0.0	0.0	0.0	0.0
28.1	0.0	0.0	157.7	12.3
28.2	0.0	0.0	157.7	12.3
28.2	0.0	0.0	157.7	12.3
28.3	46.8	55.1	157.7	12.3
28.4	31.0	36.5	157.7	12.3
28.6	12.5	14.8	157.7	12.3
28.7	13.3	15.7	157.7	12.3
28.8	15.5	18.2	157.7	12.3
28.9	25.2	29.7	157.7	12.3
29.0	29.2	34.4	157.7	12.3
29.1	35.0	41.2	157.7	12.3
29.2	39.6	46.7	157.7	12.3
29.3	43.8	51.6	157.7	12.3
29.4	47.8	56.4	157.7	12.3
29.5	51.3	60.5	157.7	12.3
29.6	54.5	64.2	157.7	12.3
29.7	58.1	68.5	157.7	12.3
29.8	60.3	71.0	157.7	12.3
29.8	61.1	71.9	157.7	12.3
29.9	63.8	75.2	157.7	12.3
30.0	66.4	78.3	157.7	12.3
30.1	69.0	81.3	157.7	12.3
30.2	71.5	84.3	157.7	12.3
30.3	73.9	87.1	157.7	12.3
31.3	95.3	112.3	157.7	12.3
32.3	113.0	133.1	157.7	12.3
33.3	128.2	151.1	157.7	12.3
34.3	141.8	167.2	157.7	12.3
34.8	147.5	173.9	157.7	12.3
35.3	154.0	181.6	157.7	12.3
36.3	255.5	301.7	2311.3	359.4
37.3	364.4	431.1	3697.8	614.5
38.3	367.7	435.0	3727.8	628.4

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
39.3	362.5	428.8	3670.1	622.1
40.0	358.5	424.1	3626.2	616.7
40.3	356.8	422.1	3607.3	614.3
41.3	351.3	415.5	3545.2	606.6
42.3	345.9	409.0	3484.4	598.9
43.3	340.6	402.8	3425.0	591.4
44.3	335.6	396.8	3367.3	584.1
45.3	330.7	391.0	3311.1	576.9
46.1	327.0	386.6	3267.2	571.3
46.3	326.0	385.5	3256.4	569.9
47.3	321.5	380.1	3203.3	563.1
48.3	317.1	374.9	3151.7	556.5
49.3	312.9	369.8	3101.4	550.0
50.3	308.8	365.0	3052.5	543.7
51.3	304.9	360.3	3004.9	537.6
52.3	301.0	355.8	2958.5	531.6
53.0	298.4	352.7	2926.7	527.5
53.3	297.3	351.4	2913.3	525.7
54.3	293.8	347.1	2869.2	520.0
55.3	290.3	343.0	2826.1	514.4
56.3	286.9	338.9	2784.1	509.0
57.3	283.6	335.1	2743.1	503.6
58.3	280.4	331.3	2703.0	498.4
59.3	242.9	286.7	2184.4	434.4
60.3	240.6	284.0	2153.4	430.1
60.6	239.9	283.2	2144.2	428.9
61.3	238.3	281.3	2123.1	425.9
62.3	236.1	278.8	2093.5	421.9
63.3	234.0	276.3	2064.5	417.8
64.3	232.0	273.8	2036.1	413.9
65.3	229.9	271.4	2008.3	410.0
66.3	228.0	269.1	1981.1	406.2
67.3	458.8	543.7	349.1	256.1
68.3	468.5	555.3	353.1	262.1
69.3	460.9	546.2	349.5	257.2
70.3	452.9	536.7	345.8	252.2

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
71.3	445.0	527.3	342.0	247.2
72.3	437.1	517.8	338.3	242.1
73.3	429.2	508.3	334.6	237.2
74.3	421.9	499.6	331.2	232.6
74.7	419.0	496.2	329.9	230.8
75.3	414.7	491.1	327.9	228.2
76.3	407.6	482.6	324.6	223.8
77.3	400.7	474.3	321.4	219.5
78.3	393.8	466.2	318.3	215.3
79.3	387.1	458.1	315.2	211.2
80.3	380.5	450.2	312.2	207.2
81.3	373.9	442.5	309.2	203.2
82.3	367.5	434.8	306.3	199.4
83.3	361.3	427.4	303.5	195.6
84.3	355.1	420.1	300.7	192.0
85.3	349.1	412.9	298.0	188.4
86.3	343.3	406.0	295.4	185.0
87.3	337.6	399.2	292.9	181.6
88.3	332.0	392.5	290.4	178.4
89.4	326.0	385.4	287.7	174.9
90.3	321.3	379.8	285.7	172.2
92.3	311.2	367.8	281.2	166.3
94.3	301.7	356.5	277.1	160.9
96.3	292.7	345.9	273.2	155.8
98.3	284.4	336.0	269.6	151.2
100.3	276.6	326.7	266.2	146.8
102.3	269.3	318.1	263.1	142.8
104.3	262.6	310.1	260.3	139.1
106.3	256.3	302.6	257.6	135.6
107.8	251.9	297.4	255.8	133.2
108.3	250.5	295.8	255.2	132.5
110.3	245.1	289.4	252.9	129.6
112.3	240.2	283.6	250.9	126.9
114.3	235.7	278.2	249.0	124.5
116.3	231.5	273.3	247.3	122.3
118.3	227.7	268.8	245.7	120.3
120.3	224.3	264.7	244.3	118.5

Table 6.5-9 (Cont.)

DEPS Break Minimum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No.1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
122.3	221.1	261.0	243.0	116.8
124.3	218.3	257.6	241.8	115.3
126.3	215.7	254.5	240.8	114.0
128.3	213.3	251.7	239.8	112.7
130.2	211.3	249.4	239.0	111.7
130.3	211.2	249.2	239.0	111.6
132.3	209.3	247.0	238.2	110.7
134.3	207.6	245.0	237.5	109.8
136.3	206.1	243.2	236.9	109.0
138.3	204.8	241.6	236.4	108.3
140.3	203.6	240.2	235.9	107.7
142.3	202.6	239.0	235.5	107.2
144.3	201.7	237.9	235.1	106.7
146.3	200.9	237.0	234.8	106.3
148.3	200.2	236.2	234.5	105.9
150.3	199.6	235.5	234.3	105.6
152.3	199.1	235.0	234.1	105.4
154.3	198.7	234.5	233.9	105.1
155.3	198.5	234.2	233.8	105.0
156.3	198.4	234.1	233.7	105.0
158.3	198.1	233.7	233.6	104.8
160.3	197.9	233.5	233.5	104.7
162.3	197.8	233.3	233.5	104.6
164.3	197.7	233.2	233.4	104.5
166.3	197.6	233.2	233.4	104.5
168.3	197.6	233.2	233.4	104.5
170.3	197.7	233.2	233.4	104.5
172.3	197.8	233.3	233.4	104.5
174.3	197.9	233.4	233.4	104.6
176.3	198.0	233.6	233.5	104.6
178.3	198.2	233.8	233.5	104.7
180.3	198.4	234.1	233.6	104.8
182.1	198.6	234.3	233.7	104.9

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-10

DEPS Break Maximum ECCS Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
27.2	0.0	0.0	0.0	0.0
27.8	0.0	0.0	0.0	0.0
27.9	0.0	0.0	0.0	0.0
28.1	0.0	0.0	241.1	18.8
28.2	0.0	0.0	241.1	18.8
28.2	0.0	0.0	241.1	18.8
28.3	74.4	87.6	241.1	18.8
28.4	22.8	26.8	241.1	18.8
28.5	15.2	17.9	241.1	18.8
28.6	17.3	20.3	241.1	18.8
28.7	22.7	26.7	241.1	18.8
28.8	27.1	31.9	241.1	18.8
28.9	31.9	37.5	241.1	18.8
29.0	37.6	44.3	241.1	18.8
29.1	42.3	49.8	241.1	18.8
29.2	46.5	54.8	241.1	18.8
29.3	50.7	59.7	241.1	18.8
29.5	54.1	63.8	241.1	18.8
29.6	57.9	68.2	241.1	18.8
29.7	61.0	71.9	241.1	18.8
29.8	63.9	75.3	241.1	18.8
29.9	66.7	78.5	241.1	18.8
30.0	69.4	81.7	241.1	18.8
30.1	72.0	84.8	241.1	18.8
30.2	74.5	87.8	241.1	18.8
30.3	77.0	90.8	241.1	18.8
31.3	99.4	117.1	241.1	18.8
32.3	117.4	138.4	241.1	18.8
33.3	133.1	156.9	241.1	18.8
34.3	147.3	173.7	241.1	18.8
34.6	151.0	178.0	241.1	18.8
35.3	159.9	188.6	241.1	18.8
36.3	357.7	423.0	3654.2	570.9
37.3	393.9	466.2	4034.5	656.1
38.3	390.1	461.7	3992.6	653.5
39.3	384.2	454.7	3930.0	646.0

Table 6.5-10 (Cont.)

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
39.6	382.5	452.6	3911.0	643.6
40.3	378.4	447.8	3866.8	638.1
41.3	372.7	441.0	3804.6	630.3
42.3	367.2	434.4	3743.9	622.6
43.3	361.9	428.1	3684.7	615.1
44.3	356.7	422.0	3627.1	607.7
45.3	351.8	416.0	3571.2	600.6
45.4	351.3	415.5	3565.7	599.9
46.3	347.0	410.3	3516.8	593.6
47.3	342.3	404.8	3463.9	586.8
48.3	337.9	399.5	3412.5	580.2
49.3	333.6	394.4	3362.5	573.8
50.3	329.4	389.4	3313.9	567.5
51.3	325.4	384.6	3266.6	561.4
52.0	322.6	381.4	3234.2	557.3
52.3	321.4	380.0	3220.5	555.5
53.3	317.7	375.5	3175.6	549.7
54.3	314.0	371.1	3131.8	544.0
55.3	310.4	366.9	3089.0	538.5
56.3	307.0	362.8	3047.4	533.0
57.3	303.6	358.8	3006.6	527.7
58.3	300.3	354.9	2966.9	522.6
59.3	285.7	337.7	2725.6	502.8
59.3	266.9	315.4	2402.0	470.9
60.3	259.8	306.8	2436.2	457.3
61.3	257.4	304.0	2406.0	453.2
62.3	255.2	301.3	2376.5	449.2
63.3	252.9	298.7	2347.6	445.2
64.3	250.8	296.1	2319.4	441.3
65.3	248.7	293.6	2291.7	437.5
66.3	246.6	291.1	2264.6	433.7
67.3	244.6	288.7	2238.1	430.1
68.3	363.1	429.6	374.8	189.2
69.3	363.0	429.4	375.5	189.1
70.3	362.8	429.1	376.5	188.9
71.3	362.5	428.9	377.5	188.7

Table 6.5-10 (Cont.)

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
72.3	362.3	428.5	378.6	188.5
73.3	362.0	428.2	379.6	188.4
74.3	361.7	427.9	380.7	188.2
74.5	361.6	427.8	380.9	188.1
75.3	361.4	427.5	381.8	188.0
76.3	361.0	427.1	382.9	187.8
77.3	360.7	426.7	384.0	187.6
78.3	360.3	426.2	385.2	187.4
79.3	359.9	425.7	386.4	187.1
80.3	359.5	425.2	387.7	186.9
81.3	359.0	424.7	389.0	186.7
82.3	358.5	424.1	390.3	186.5
83.3	358.0	423.5	391.7	186.2
84.3	357.4	422.8	393.2	186.0
85.3	356.8	422.1	394.7	185.8
86.3	356.2	421.4	396.2	185.5
87.3	355.6	420.6	397.8	185.2
88.3	354.9	419.8	399.5	185.0
88.9	354.4	419.2	400.5	184.8
90.3	353.4	418.0	403.0	184.5
92.3	351.7	416.0	406.7	183.9
94.3	349.9	413.9	410.6	183.3
96.3	348.0	411.5	414.7	182.8
98.3	345.9	409.0	419.0	182.2
100.3	343.6	406.3	423.5	181.6
102.3	341.2	403.4	428.2	181.0
104.3	338.6	400.4	433.1	180.5
104.4	338.5	400.2	433.3	180.5
106.3	335.9	397.2	438.1	179.9
108.3	333.1	393.8	443.3	179.4
110.3	330.1	390.3	448.7	178.9
112.3	327.0	386.6	454.3	178.4
114.3	323.8	382.8	460.0	177.9
116.3	320.4	378.8	465.9	177.5
118.3	316.9	374.6	472.0	177.1
120.3	313.3	370.3	478.3	176.7
121.3	311.4	368.1	481.5	176.6

Table 6.5-10 (Cont.)

DEPS Break Maximum ECCS
Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
122.3	309.5	365.8	484.7	176.4
124.3	305.6	361.1	491.3	176.1
126.3	301.5	356.3	498.2	175.9
128.3	297.3	351.3	505.2	175.7
130.3	292.9	346.1	512.4	175.6
132.3	288.3	340.7	519.8	175.5
134.3	283.6	335.0	527.5	175.5
136.3	278.7	329.2	535.4	175.5
138.3	273.6	323.1	543.5	175.6
140.3	268.3	316.9	551.9	175.8
140.5	267.7	316.2	552.8	175.8
142.3	262.8	310.3	560.6	176.0
144.3	257.0	303.5	569.6	176.4
146.3	251.0	296.4	578.8	176.8
148.3	244.8	289.0	588.4	177.3
150.3	238.3	281.3	598.3	177.9
152.3	231.4	273.2	608.7	178.6
154.3	224.2	264.7	619.5	179.4
156.3	216.7	255.7	630.7	180.4
158.3	208.7	246.3	642.5	181.5
160.3	200.4	236.4	654.7	182.8
162.3	191.5	225.9	667.6	184.2
163.7	185.0	218.2	677.0	185.3

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-11

DEPS Break Minimum ECCS Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
27.2	185.8	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
28.1	184.0	21.923	0.000	0.77	1.04	0.000	6394.7	5763.9	0.0	97.24
28.2	183.6	22.509	0.000	0.95	1.05	0.000	6374.0	5743.2	0.0	97.24
28.2	183.4	22.418	0.126	1.05	1.06	0.225	6353.4	5722.6	0.0	97.23
28.6	183.1	2.305	0.095	1.31	1.49	0.203	6278.0	5647.2	0.0	97.20
28.8	183.1	2.493	0.117	1.34	1.90	0.217	6248.5	5617.7	0.0	97.19
28.9	183.2	2.442	0.147	1.36	2.15	0.270	6209.7	5578.9	0.0	97.18
29.1	183.3	2.475	0.186	1.40	2.56	0.295	6171.6	5540.8	0.0	97.17
29.8	183.5	2.375	0.298	1.50	3.96	0.329	6043.0	5412.1	0.0	97.12
30.3	183.8	2.321	0.364	1.57	5.01	0.339	5946.7	5315.9	0.0	97.09
34.8	185.8	2.601	0.613	2.00	13.40	0.359	5290.4	4659.6	0.0	96.80
37.3	187.2	3.915	0.675	2.24	16.11	0.536	4542.5	3949.9	0.0	96.56
39.3	188.3	3.760	0.698	2.44	16.12	0.535	4327.0	3734.5	0.0	96.43
40.0	188.7	3.703	0.703	2.50	16.12	0.533	4268.6	3675.2	0.0	96.38
46.1	192.7	3.364	0.727	3.01	16.12	0.518	3829.7	3228.9	0.0	96.00
53.0	197.5	3.127	0.735	3.51	16.12	0.503	3434.8	2827.8	0.0	95.58
60.6	203.0	2.748	0.738	4.00	16.12	0.459	2559.2	1940.3	0.0	94.19
66.3	207.2	2.655	0.740	4.34	16.12	0.450	2374.9	1754.0	0.0	93.77
67.3	208.0	4.011	0.748	4.41	16.02	0.599	566.8	0.0	0.0	78.00
68.3	209.0	4.043	0.748	4.49	15.84	0.600	562.2	0.0	0.0	78.00
69.3	210.0	3.980	0.748	4.58	15.66	0.600	564.3	0.0	0.0	78.00
74.7	215.5	3.642	0.749	5.01	14.79	0.595	575.5	0.0	0.0	78.00
82.3	223.3	3.234	0.750	5.55	13.87	0.587	588.1	0.0	0.0	78.00

Table 6.5-11 (Cont.)

DEPS Break Minimum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
89.4	230.5	2.910	0.750	6.01	13.28	0.579	597.2	0.0	0.0	78.00
98.3	238.4	2.589	0.750	6.51	12.85	0.568	605.5	0.0	0.0	78.00
107.8	246.3	2.341	0.750	7.00	12.66	0.556	611.3	0.0	0.0	78.00
120.3	252.8	2.130	0.751	7.58	12.72	0.544	615.8	0.0	0.0	78.00
130.2	257.7	2.028	0.753	8.00	12.91	0.537	617.7	0.0	0.0	78.00
144.3	263.8	1.947	0.757	8.58	13.32	0.531	619.1	0.0	0.0	78.00
155.3	267.9	1.915	0.760	9.00	13.70	0.529	619.6	0.0	0.0	78.00
170.3	272.8	1.895	0.765	9.57	14.26	0.529	619.7	0.0	0.0	78.00
182.1	276.2	1.891	0.770	10.00	14.72	0.530	619.6	0.0	0.0	78.00

Table 6.5-12

DEPS Break Maximum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
27.2	185.5	0.000	0.000	0.00	0.00	0.250	0.0	0.0	0.0	0.00
28.1	183.5	23.012	0.000	0.78	1.06	0.000	6770.0	5805.3	0.0	96.31
28.2	18.9	24.009	0.000	1.08	1.07	0.000	6728.0	5763.3	0.0	96.29
28.5	182.6	2.385	0.100	1.31	1.54	0.235	6653.8	5689.1	0.0	96.25
29.0	182.8	2.522	0.190	1.40	2.60	0.306	6550.3	5585.6	0.0	96.21
29.7	183.0	2.420	0.293	1.50	3.98	0.333	6428.3	5463.6	0.0	96.15
30.3	183.2	2.360	0.369	1.58	5.23	0.342	6321.1	5356.4	0.0	96.09
34.6	185.2	2.652	0.614	2.00	13.80	0.360	5670.4	4705.8	0.0	95.72
37.3	186.5	4.078	0.680	2.27	16.12	0.550	4803.5	3892.8	0.0	95.30
39.3	187.6	3.880	0.701	2.47	16.12	0.547	4615.3	3702.1	0.0	95.13
39.6	187.8	3.854	0.704	2.50	16.12	0.546	4590.1	3676.5	0.0	95.10
45.4	191.4	3.513	0.727	3.00	16.12	0.533	4164.4	3242.1	0.0	94.62
52.0	195.9	3.272	0.736	3.50	16.12	0.519	3778.0	2848.2	0.0	94.10
67.3	206.8	2.742	0.741	4.49	16.12	0.467	2656.4	1708.4	0.0	91.73
68.3	207.6	3.443	0.747	4.56	16.12	0.548	918.5	0.0	0.0	78.00
69.3	208.4	3.437	0.747	4.63	16.12	0.548	918.5	0.0	0.0	78.00
74.5	213.2	3.406	0.749	5.01	16.12	0.550	919.0	0.0	0.0	78.00
82.3	221.0	3.351	0.752	5.55	16.12	0.552	919.9	0.0	0.0	78.00
88.9	228.0	3.292	0.755	6.00	16.12	0.553	922.9	0.0	0.0	78.00
98.3	237.6	3.188	0.759	6.62	16.12	0.555	922.9	0.0	0.0	78.00
104.4	243.1	3.110	0.760	7.01	16.12	0.555	924.6	0.0	0.0	78.00
114.3	250.7	2.967	0.763	7.60	16.12	0.554	927.8	0.0	0.0	78.00
121.3	255.4	2.856	0.765	8.00	16.12	0.553	930.5	0.0	0.0	78.00

Table 6.5-12 (Cont.)

DEPS Break Maximum ECCS
Principle Parameters During Reflood for IP3 SPU

Time (sec)	Flooding Temp (°F)	Flooding Rate (in/sec)	Carryover Fraction	Core Height (ft)	Downcomer Height (ft)	Flow Fraction	Injection Total (lbm/sec)	Injection Accumulator (lbm/sec)	Injection Spill (lbm/sec)	Injection Enthalpy (Btu/lbm)
132.3	261.7	2.665	0.768	8.60	16.12	0.547	935.4	0.0	0.0	78.00
140.5	265.6	2.507	0.769	9.00	16.12	0.538	939.6	0.0	0.0	78.00
152.3	270.4	2.250	0.771	9.54	16.12	0.517	946.7	0.0	0.0	78.00
163.7	274.2	1.950	0.771	10.00	16.12	0.476	954.8	0.0	0.0	78.00

Table 6.5-13

DEPS Break Minimum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
182.2	263.5	324.2	367.2	149.7
187.2	262.8	323.3	368.0	149.5
192.2	262.4	322.9	368.3	149.2
197.2	261.9	322.3	368.8	149.0
202.2	260.9	321.0	369.9	148.9
207.2	260.3	320.3	370.4	148.6
212.2	260.1	320.0	370.7	148.3
217.2	264.3	325.1	366.5	150.5
222.2	263.8	324.6	366.9	150.2
227.2	263.1	323.7	367.7	150.0
232.2	262.5	322.9	368.3	149.7
237.2	262.0	322.3	368.8	149.4
242.2	261.4	321.6	369.3	149.2
247.2	260.8	320.8	370.0	148.9
252.2	259.9	319.8	370.8	148.7
257.2	259.5	319.2	371.3	148.4
262.2	258.5	318.1	372.2	148.3
267.2	257.9	317.3	372.9	148.0
272.2	257.4	316.6	373.4	147.7
277.2	256.7	315.8	374.1	147.5
282.2	255.9	314.8	374.8	147.3
287.2	255.1	313.9	375.6	147.0
292.2	254.5	313.1	376.3	146.8
297.2	253.9	312.3	376.9	146.5
302.2	93.7	115.3	537.0	188.4
434.5	93.7	115.3	537.0	188.4
434.6	93.5	114.5	537.2	183.2
437.2	93.4	114.4	537.3	183.0
1114.8	93.4	114.4	537.3	183.0
1114.9	76.5	88.0	554.3	48.2
1623.8	69.7	80.2	561.1	49.4
1623.9	69.7	80.2	208.3	48.4
3600.0	56.7	65.3	221.2	50.8
3600.1	49.3	56.7	228.7	39.7
3916.2	47.5	54.7	230.5	40.0
3916.3	47.8	55.0	100.2	17.9

Table 6.5-13 (Cont.)

DEPS Break Minimum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10,000.0	36.0	41.5	112.0	20.0
100,000.0	19.3	22.2	128.7	23.0
1,000,000.0	8.3	9.5	139.8	25.0
10,000,000.0	2.6	3.0	145.4	26.0

Notes:

1. M&E exiting from the steam-generator side of the break
2. M&E existing from the pump side of the break

Table 6.5-14

DEPS Break Maximum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1(1)		Break Path No. 2(2)	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
163.8	158.0	193.6	806.7	207.2
168.8	157.6	193.1	807.1	206.8
173.8	157.7	193.2	807.0	206.4
178.8	157.7	193.2	807.0	206.0
183.8	157.2	192.7	807.5	205.7
188.8	157.2	192.6	807.5	205.3
193.8	157.2	192.6	807.5	204.8
198.8	156.7	192.0	808.0	204.5
203.8	156.8	192.2	807.8	204.1
208.8	156.6	191.9	808.1	203.7
213.8	156.8	192.1	807.9	206.8
218.8	156.5	191.8	808.2	206.5
223.8	156.2	191.4	808.5	206.1
228.8	156.3	191.6	808.4	205.6
233.8	156.0	191.2	808.7	205.3
238.8	156.1	191.3	808.6	204.8
243.8	156.2	191.4	808.5	204.3
248.8	155.8	190.9	808.9	204.0
253.8	155.8	190.9	808.9	203.5
258.8	155.8	190.9	808.9	203.1
263.8	155.8	190.9	808.9	202.6
268.8	155.7	190.8	809.0	202.2
273.8	155.6	190.7	809.1	201.8
278.8	155.5	190.6	809.2	201.3
283.8	155.4	190.4	809.3	200.9
288.8	155.2	190.2	809.5	200.5
293.8	155.0	189.9	809.7	200.1
298.8	155.2	190.1	809.5	203.0
303.8	154.9	189.8	809.8	202.6
308.8	154.9	189.8	809.8	202.1
313.8	154.6	189.4	810.1	201.7
318.8	154.5	189.4	810.2	201.2
323.8	154.4	189.2	810.2	200.8
328.8	154.3	189.1	810.4	200.3

Table 6.5-14 (Cont.) DEPS Break Maximum ECCS Post-Reflood M&E Releases for IP3 SPU				
	Break Path No. 1[(1)]		Break Path No. 2[(2)]	
Time	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
333.8	154.4	189.2	810.3	199.8
338.8	154.1	188.9	810.5	199.3
343.8	154.1	188.9	810.6	198.8
348.8	154.0	188.7	810.7	198.4
353.8	153.8	188.5	810.9	197.9
358.8	153.9	188.5	810.8	197.4
363.8	153.8	188.4	810.9	196.9
368.8	153.5	188.1	811.2	199.7
373.8	153.4	188.0	811.3	199.2
378.8	153.5	188.0	811.2	198.7
383.8	153.3	187.8	811.4	198.2
388.8	153.1	187.6	811.6	197.7
393.8	153.2	187.7	811.5	197.1
398.8	152.9	187.4	811.8	196.7
403.8	153.0	187.5	811.7	196.1
408.8	152.8	187.2	811.9	195.6
413.8	152.9	187.3	811.8	195.1
418.8	152.8	187.2	811.9	197.7
423.8	152.6	187.0	812.0	197.2
428.8	152.5	186.9	812.2	196.6
433.8	152.4	186.7	812.3	196.1
438.8	144.5	177.1	820.2	197.6
443.8	86.1	105.5	878.6	212.4
798.1	86.1	105.5	878.6	212.4
798.2	83.7	102.0	881.0	204.6
798.8	83.7	102.0	881.0	204.6
1033.6	83.7	102.0	881.0	204.6
1033.7	78.5	90.4	886.1	73.4
1172.7	76.6	88.1	888.1	73.8
1172.8	76.6	88.1	474.6	105.6
3119.9	60.4	69.5	490.7	108.5
3120.0	60.4	69.5	233.4	59.3
3600.0	57.7	66.3	236.1	59.7
3600.1	50.5	58.1	243.3	47.9

Table 6.5-14 (Cont.)

DEPS Break Maximum ECCS
Post-Reflood M&E Releases for IP3 SPU

Time	Break Path No. 1[1]		Break Path No. 2[2]	
	Flow	Energy	Flow	Energy
sec	lbm/sec	Thousand Btu/sec	lbm/sec	Thousand Btu/sec
10,000.0	36.7	42.2	257.1	50.6
100,000.0	19.6	22.6	274.1	53.9
1,000,000.0	8.4	9.7	285.4	56.1
10,000,000.0	2.6	3.0	291.1	57.3

Notes:

1. M&E exiting the steam-generator side of the break
2. M&E exiting the pumpside of the break

Table 6.5-15 LOCA M&E Release Analysis for Core Decay Heat Fraction	
Time (sec)	Decay Heat Generation Rate (Btu/Btu)
1.00E+01	0.053876
1.50E+01	0.050401
2.00E+01	0.048018
4.00E+01	0.042401
6.00E+01	0.039244
8.00E+01	0.037065
1.00E+02	0.035466
1.50E+02	0.032724
2.00E+02	0.030936
4.00E+02	0.027078
6.00E+02	0.024931
8.00E+02	0.023389
1.00E+03	0.022156
1.50E+03	0.019921
2.00E+03	0.018315
4.00E+03	0.014781
6.00E+03	0.013040
8.00E+03	0.012000
1.00E+04	0.011262
1.50E+04	0.010097
2.00E+04	0.009350
4.00E+04	0.007778
6.00E+04	0.006958
8.00E+04	0.006424
1.00E+05	0.006021
1.50E+05	0.005323
4.00E+05	0.003770
6.00E+05	0.003201
8.00E+05	0.002834
1.00E+06	0.002580
1.00E+07	0.000808

Table 6.5-16

DEPS Break Minimum ECCS Mass Balance
IP3 SPU

		Mass Balance						
Time (sec)		0.00	27.20	27.20	182.14	434.58	1114.84	3600.00
		Mass (thousand lbm)						
Initial	In RCS and accumulators	732.01	732.01	732.01	732.01	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00	94.02	253.21	682.29	1552.63
	Total added	0.00	0.00	0.00	94.02	253.21	682.29	1552.63
Total Available		732.01	732.01	732.01	826.03	985.21	1414.29	2284.64
Distribution	Reactor coolant	527.21	40.55	67.50	134.67	134.67	134.67	134.67
	Accumulator	204.80	159.14	132.19	0.00	0.00	0.00	0.00
	Total contents	732.01	199.70	199.70	134.67	134.67	134.67	134.67
Effluent	Break flow	0.00	532.30	532.30	691.35	850.53	1279.61	2149.98
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	532.30	532.30	691.35	850.53	1279.61	2149.98
Total Accountable		732.01	731.99	731.99	826.01	985.20	1414.28	2284.64

Table 6.5-17

DEPS Break Maximum ECCS Mass Balance
IP3 SPU

		Mass Balance						
Time (sec)		0.00	27.20	27.20	163.73	798.20	1033.63	3600.00
		Mass (thousand lbm)						
Initial	In RCS and accumulators	732.01	732.01	732.01	732.01	732.01	732.01	732.01
Added Mass	Pumped injection	0.00	0.00	0.00	126.74	738.74	965.85	2314.17
	Total added	0.00	0.00	0.00	126.74	738.74	965.85	2314.17
Total Available		732.01	732.01	732.01	858.74	1470.74	1697.86	3046.18
Distribution	Reactor coolant	527.21	40.55	66.31	137.06	137.06	137.06	137.06
	Accumulator	204.80	159.14	133.38	0.00	0.00	0.00	0.00
	Total contents	732.01	199.70	199.70	137.06	137.06	137.06	137.06
Effluent	Break flow	0.00	532.30	532.30	721.67	1333.67	1560.78	2909.14
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	532.30	532.30	721.67	1333.67	1560.78	2909.14
Total Accountable		732.01	731.99	731.99	858.73	1470.73	1697.84	3046.20

Table 6.5-18

DEPS Break Minimum ECCS Energy Balance
IP3 SPU

		Energy Balance						
Time (sec)		0.00	27.20	27.20	182.14	434.58	1114.84	3600.00
		Energy (million Btu)						
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34	775.34	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00	7.33	19.75	53.22	173.60
	Decay heat	0.00	7.65	7.65	25.09	47.82	98.19	235.35
	Heat from secondary	0.00	10.72	10.72	10.72	10.72	10.72	10.72
	Total added	0.00	18.37	18.37	43.15	78.29	162.14	419.68
Total Available		775.34	793.71	793.71	818.49	853.63	937.48	1195.02
Distribution	Reactor coolant	305.75	9.37	12.05	36.23	36.23	36.23	36.23
	Accumulator	20.35	15.81	13.13	0.00	0.00	0.00	0.00
	Core stored	26.87	14.68	14.68	3.95	3.78	3.55	2.71
	Primary metal	166.23	158.03	158.03	127.92	94.29	70.05	53.31
	Secondary metal	40.98	40.83	40.83	36.70	30.14	20.07	15.24
	Steam generator	215.15	232.85	232.85	205.85	165.18	106.47	80.08
	Total contents	775.34	471.57	471.57	410.65	329.61	236.37	187.56
Effluent	Break flow	0.00	321.67	321.67	400.48	516.66	698.75	1008.11
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	321.67	321.67	400.48	516.66	698.75	1008.11
Total Accountable		775.34	793.23	793.23	811.13	846.27	935.11	1195.67

Table 6.5-19

DEPS Break Maximum ECCS Energy Balance
IP3 SPU

		Energy Balance						
Time (sec)		.00	27.20	27.20	163.73	798.20	1033.63	3600.00
		Energy (million Btu)						
Initial Energy	In RCS, accumulators and steam generators	775.34	775.34	775.34	775.34	775.34	775.34	775.34
Added Energy	Pumped injection	0.00	0.00	0.00	9.89	57.62	75.34	321.96
	Decay heat	0.00	7.65	7.65	23.26	76.05	92.67	235.26
	Heat from secondary	0.00	10.72	10.72	10.72	10.72	10.72	10.72
	Total added	0.00	18.37	18.37	43.87	144.40	178.73	567.95
Total Available		775.34	793.71	793.71	819.21	919.74	954.07	1343.29
Distribution	Reactor coolant	305.75	9.37	11.93	37.02	37.02	37.02	37.02
	Accumulator	20.35	15.81	13.25	0.00	0.00	0.00	0.00
	Core stored	26.87	14.68	14.68	3.95	3.78	3.69	2.71
	Primary metal	166.23	158.03	158.03	127.18	79.50	71.49	53.32
	Secondary metal	40.98	40.83	40.83	36.27	23.54	20.26	15.22
	Steam generator	215.15	232.85	232.85	203.11	125.58	107.48	80.01
	Total contents	775.34	471.57	471.57	407.52	269.40	239.93	188.27
Effluent	Break flow	0.00	321.67	321.67	404.33	642.97	698.44	1144.08
	ECCS spill	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total effluent	0.00	321.67	321.67	404.33	642.97	698.44	1144.08
Total Accountable		775.34	793.23	793.23	811.85	912.38	939.37	1332.35

Table 6.5-20 DEHL Break Sequence of Events for IP3 SPU	
Time (sec)	**Event Description**
0.0	Break occurs, LOOP is assumed
0.6	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint at 1648.7 psia reached in blowdown
15.2	Broken-loop accumulator begins injecting water
15.5	Intact-loop accumulator begins injecting water
25.6	End-of-blowdown phase

Table 6.5-21 DEPS Break Minimum ECCS Sequence of Events for IP3 SPU	
Time (sec)	**Event Description**
0.0	Break occurs, and LOOP is assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
16.0	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
58.4	Broken-loop accumulator water injection ends
66.5	Intact-loop accumulator water injection ends
182.1	End of reflood phase
1623.8	Cold leg recirculation begins
23,400.0	Hot leg recirculation begins
1.0E+07	Transient modeling terminated

Table 6.5-22

DEPS Break Maximum ECCS
Sequence of Events for IP3 SPU

Time (sec)	Event Description
0.0	Break occurs, and LOOP are assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
4.0	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
59.2	Broken-loop accumulator water injection ends
67.4	Intact-loop accumulator water injection ends
163.7	End-of-reflood phase
1172.7	Cold leg recirculation begins
1.0E+07	Transient modeling terminated

Table 6.5-23 IP3 LOCA Containment Response Analysis Parameters	
SW Temperature (°F)	95
RWST Water Temperature (°F)	110
Initial Containment Temperature (°F)	130
Initial Containment Pressure (psia)	17.2
Initial Relative Humidity (%)	20
Net-Free Volume (ft^3)	2.61E+06
Reactor Containment Air Recirculation Fan Coolers	
Total	5
Minimum ECCS	4
Maximum ECCS	5
Fan Cooler Initiation Setpoint (psig)	5.12
Delay Time (sec)	48.21
Containment Spray Pumps	
Total	2
Minimum ECCS	1
Maximum ECCS	1
Flow Rate (gpm) Injection Phase Recirculation Phase	 see Table 6.5-25 970
Containment Spray Initiation Setpoint (psig)	24.63
Delay Time (sec)	60
ECCS Recirculation Switchover (sec) Minimum ECCS Maximum ECCS	 1623.4 1172.7
Containment Spray Termination (sec) Minimum ECCS Maximum ECCS	 3355 3119.9

Table 6.5-23 (Cont.) IP3 LOCA Containment Response Analysis Parameters	
ECCS Flow Rates	
Minimum ECCS	
Injection Alignment (gpm)	2871.2
Recirculation Alignment (gpm)	1864.0
Maximum ECCS	
Injection Alignment (gpm)	5394.5
Recirculation Alignment (gpm)	6320.5
Residual Heat Removal System	
RHR Heat Exchangers	
Total	2
Minimum ECCS	1
Maximum ECCS	2
UA (million Btu / hr °F Hx)	0.62
CCW Flow Through RHR Heat Exchanger (gpm/Hx)	1096
CCW Heat Exchangers	
Total	3
Minimum ECCS	2
Maximum ECCS	3
UA (million Btu / hr °F Hx)	1.44
Total CCW Flow Through CCW Heat Exchangers (gpm)	3710
Total SW Flow Through CCW Heat Exchangers (gpm)	7221
Additional Heat Loads on CCW Heat Exchanger (Btu/hr)	18.85E+06

Table 6.5-24 IP3 RCFC Performance	
Containment Temperature (°F)	**Heat Removal Rate (Btu/hr/RCFC)**
271	46,952,250
250	39,551,200
230	31,810,100
210	24,063,770
190	19,528,450
170	14,984,710
150	10,516,890
130	6,253,162
110	2,426,960

Table 6.5-25

IP3 Minimum Containment Spray Assumed

Containment Pressure (psig)	Containment Spray Flow Rate (gpm)
0	2750.8
10	2656.8
20	2558.0
25	2507.4
35	2403.8
45	2296.5
50	2237.9

Table 6.5-26 DEPS Break Minimum ECCS IP3 SPU Sequence of Events	
Time (sec)	Event Description
0.0	Break occurs, reactor trip and LOOP power are assumed
0.66	Reactor trip on low-pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
8	Containment spray initiation pressure setpoint reached
16	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.8	SI begins
48.74	RCFCs actuate
58.4	Broken-loop accumulator water injection ends
66.5	Intact-loop accumulator water injection ends
67.81	Containment spray pump starts
182.1	End of reflood
1118	Peak pressure and temperature occur
1623.8	RHR/HHSI alignment for recirculation
3355	Containment spray is terminated
23,400	Hot leg recirculation
1.0E+07	Transient modeling terminated

Table 6.5-27

DEPS Break Maximum ECCS
IP3 SPU Sequence of Events

Time (sec)	Event Description
0.0	Break occurs, reactor trip and LOOP power are assumed
0.66	Reactor trip on low pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint 1648.7 psia reached in blowdown
8	Containment spray initiation pressure setpoint reached
16	Main feedwater flow control valve closed
16.9	Broken-loop accumulator begins injecting water
17.5	Intact-loop accumulator begins injecting water
27.2	End-of-blowdown phase
27.3	Peak pressure and temperature occur
27.8	SI begins
48.74	RCFCs actuate
59.2	Broken-loop accumulator water injection ends
67.4	Intact-loop accumulator water injection ends
67.81	Containment spray pump starts
163.7	End of reflood
1172.7	RHR/HHSI alignment for recirculation
3119.9	Containment spray is terminated
1.0E+07	Transient modeling terminated

Table 6.5-28

DEHL Break
IP3 SPU Sequence of Events

Time (sec)	Event Description
0.0	Break occurs, reactor trip and LOOP are assumed
0.6	Reactor trip on low pressurizer pressure of 1748.7 psia
1	Fan cooler initiation pressure setpoint reached
4	Low-pressurizer pressure SI setpoint =1695 psia reached
8	Containment spray initiation pressure setpoint reached
15.2	Broken-loop accumulator begins injecting water
15.5	Intact-loop accumulator begins injecting water
24.2	Peak pressure and temperature occur
25.6	End-of-blowdown phase
25.6	Transient modeling terminated

Table 6.5-29

IP3 Containment Heat Sinks

No.	Material	Heat Transfer Area (ft^2)	Thickness (ft)
1.	Paint Steel Concrete	41,302	0.000625 0.03125 1.0
2.	Paint Steel Concrete	28,613	0.000625 0.04167 1.0
3.	Paint Concrete	15,000	0.000625 1.0
4.	Stainless Steel Concrete	10,000	0.03125 1.0
5.	Paint Concrete	61,000	0.000625 1.0
6.	Paint Steel	68,792	0.000625 0.0417
7.	Paint Steel	81,704	0.000625 0.03125
8.	Paint Steel	27,948	0.000625 0.02083
9.	Paint Steel	69,800	0.000625 0.015625
10.	Paint Steel	3000	0.000625 0.01042
11.	Paint Steel	22,000	0.000625 0.01152
12.	Paint Steel	10,000	0.000625 0.0052

Table 6.5-30

IP3 Thermo-Physical Properties of Containment Heat Sinks

Material	Thermal Conductivity (Btu / hr ft °F)	Volumetric Heat Capacity (Btu / ft^3 °F)
Paint	0.2083	36.86
Steel	26.0	56.35
Stainless Steel	8.6	56.35
Concrete	0.8	28.8

Table 6.5-31 DEPS Break Minimum ECCS IP3 SPU			
Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.0	149.4	189.9
1	7.4	167.5	204.2
2	11.8	194.5	216.5
3	15.2	210.3	222.9
4	17.9	219.4	227.1
5	20.0	223.9	230.2
6	21.8	226.1	232.8
7	23.5	227.8	235.1
8	25.1	228.6	237.0
9	26.8	232.6	239.1
19	37.4	253.7	250.6
29	38.1	254.9	252.2
39	36.9	252.8	249.9
49	36.5	252.1	245.9
59	36.3	251.6	243.6
69	36.2	251.4	243.3
79	36.6	252.1	243.4
89	37.0	252.7	243.5
99	37.2	253.0	243.7
109	37.3	253.1	243.8
119	37.4	253.2	244.0
129	37.5	253.3	244.1
139	37.5	253.3	244.3
149	37.6	253.3	244.4
159	37.6	253.3	244.5
169	37.6	253.4	244.7
179	37.7	253.4	244.8
189	37.8	253.7	245.0
199	38.0	254.1	245.2
299	40.5	258.2	247.3
399	40.2	257.6	250.0
499	40.2	257.6	252.1
599	40.3	257.8	253.9
699	40.6	258.2	255.3
799	40.9	258.7	256.6
899	41.2	259.2	257.7
999	41.6	259.8	258.7
1999	35.3	248.9	239.7
2999	29.4	237.0	241.6
3999	27.9	233.7	240.5

Table 6.5-31 (Cont.) DEPS Break Minimum ECCS IP3 SPU			
Time (sec)	**Pressure (psig)**	**Steam Temperature (°F)**	**Sump Temperature (°F)**
4999	27.3	232.3	238.6
5999	26.7	230.8	236.8
6999	26.0	229.2	235.0
7999	25.3	227.3	233.4
8999	24.5	225.3	231.8
9999	23.7	223.2	230.3
99,999	12.0	181.6	197.2
199,999	10.7	174.9	191.7
299,999	10.3	172.0	191.7
399,999	10.1	168.2	189.8
499,999	9.4	164.3	187.0
599,999	8.9	160.6	185.2
699,999	8.4	157.5	183.8
799,999	7.9	153.4	181.7
899,999	7.4	149.8	180.5
999,999	7.0	146.1	179.0
10,000,000	4.4	127.4	170.7

Table 6.5-32

DEPS Break Maximum ECCS
IP3 SPU

Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.0	149.4	189.9
1	7.4	167.5	204.2
2	11.8	194.5	216.5
3	15.2	210.3	222.9
4	17.9	219.4	227.1
5	20.0	223.9	230.2
6	21.8	226.1	232.8
7	23.5	227.8	235.1
8	25.1	228.6	237.0
9	26.8	232.6	239.1
19	37.4	253.7	250.6
29	38.1	254.9	252.2
39	37.0	252.9	249.3
49	36.6	252.2	244.6
59	36.3	251.7	241.8
69	36.2	251.4	240.9
79	36.3	251.6	241.2
89	36.6	252.0	241.5
99	36.8	252.4	241.8
109	37.1	252.7	242.1
119	37.3	253.0	242.5
129	37.5	253.3	242.8
139	37.6	253.4	243.2
149	37.7	253.5	243.6
159	37.7	253.5	244.1
169	37.6	253.3	244.6
179	37.4	253.0	245.1
189	37.3	252.8	245.6
199	37.2	252.6	246.1
299	36.5	251.3	249.6
399	36.3	250.9	251.7
499	35.6	249.7	253.0
599	34.7	247.9	254.0
699	33.9	246.4	254.8
799	33.2	245.0	255.3
899	32.5	243.7	255.3
999	31.9	242.4	255.2
1999	25.5	228.1	243.7
2999	21.0	215.6	241.2
3999	22.3	219.4	238.8

Table 6.5-32 (Cont.)

DEPS Break Maximum ECCS
IP3 SPU

Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
4999	22.4	219.7	235.9
5999	22.2	219.3	233.5
6999	21.9	218.3	231.4
7999	21.5	217.0	229.5
8999	20.9	215.2	228.0
9999	20.2	213.3	226.5
99,999	11.5	179.1	204.1
199,999	10.8	175.0	201.9
299,999	10.3	172.4	200.7
399,999	9.9	169.8	199.4
499,999	9.5	167.1	198.1
599,999	9.1	164.5	197.0
699,999	8.7	161.9	195.9
799,999	8.3	159.4	194.8
899,999	7.9	156.8	193.7
999,999	7.6	154.1	192.6
10,000,000	6.0	141.1	186.9

Table 6.5-33 DEHL Break IP3 SPU			
Time (sec)	Pressure (psig)	Steam Temperature (°F)	Sump Temperature (°F)
0.001	2.5	130.0	130.0
0.5	5.1	149.8	182.5
1.0	7.1	165.0	197.7
2.0	10.9	188.7	212.6
3.0	14.3	205.2	221.1
4.0	17.2	216.0	226.9
5.0	19.8	222.9	231.5
6.0	22.2	227.7	235.3
7.0	24.2	229.9	238.1
8.0	26.0	231.1	240.6
9.0	27.8	234.9	242.9
10.0	29.7	238.9	245.2
11.0	31.2	242.1	246.9
12.0	32.6	244.9	248.6
13.0	33.9	247.3	250.0
14.0	35.0	249.4	251.3
15.0	36.1	251.3	252.3
16.0	37.0	252.9	253.2
17.0	37.8	254.3	253.8
18.0	38.5	255.5	254.2
19.0	39.1	256.5	254.5
20.0	39.6	257.3	254.6
21.0	39.9	257.8	254.7
22.0	40.2	258.2	254.7
23.0	40.3	258.5	254.7
24.0	40.4	258.6	254.8
25.0	40.4	258.6	254.8
25.6	40.3	258.4	254.8

Table 6.5-34

LOCA Containment Response Results for IP3 SPU

Case	Peak Pressure (psig)	Peak Steam Temperature (°F)	Pressure at 24 hours (psig)	Steam Temperature at 24 hours (°F)
DEPS Minimum ECCS	42.00 at 1118 sec	260.4 at 1118 sec	13.27	187.8
DEPS Maximum ECCS	38.94 at 23.7 sec	256.2 at 23.7 sec	12.40	183.6
DEHL	40.38 at 24.2 sec	258.6 at 24.2 sec	N/A	N/A

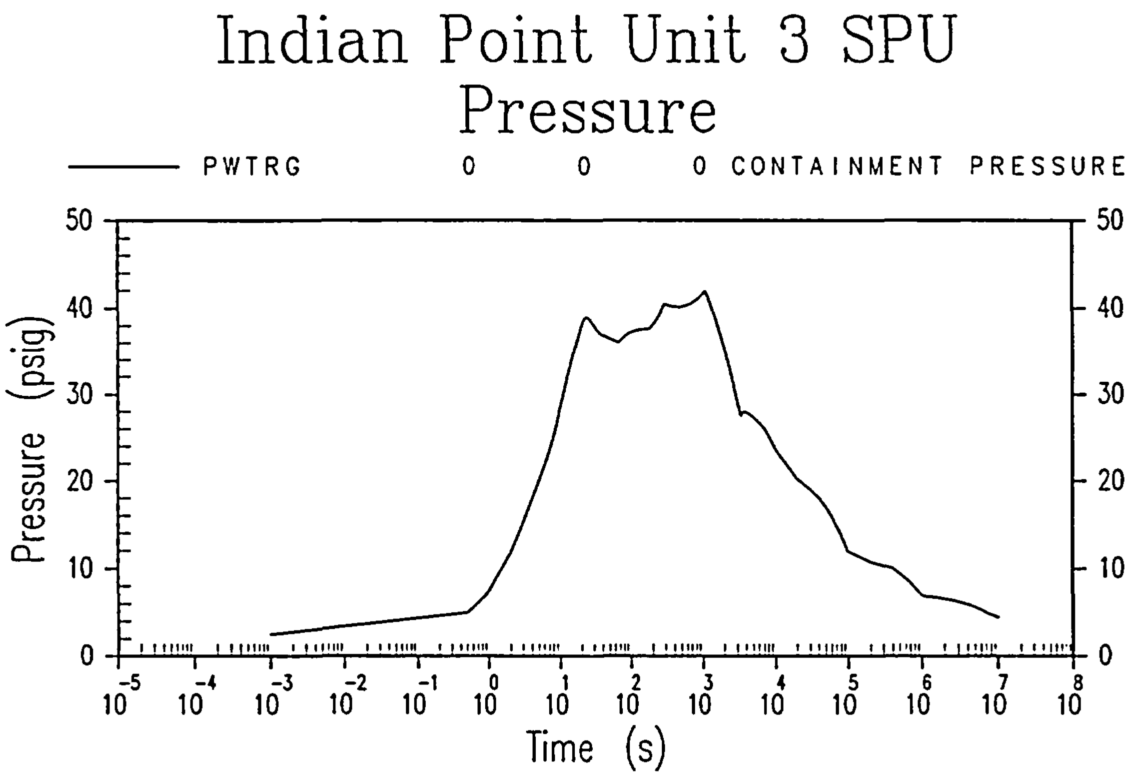


Figure 6.5-1

DEPS Break Minimum ECCS - Containment Pressure

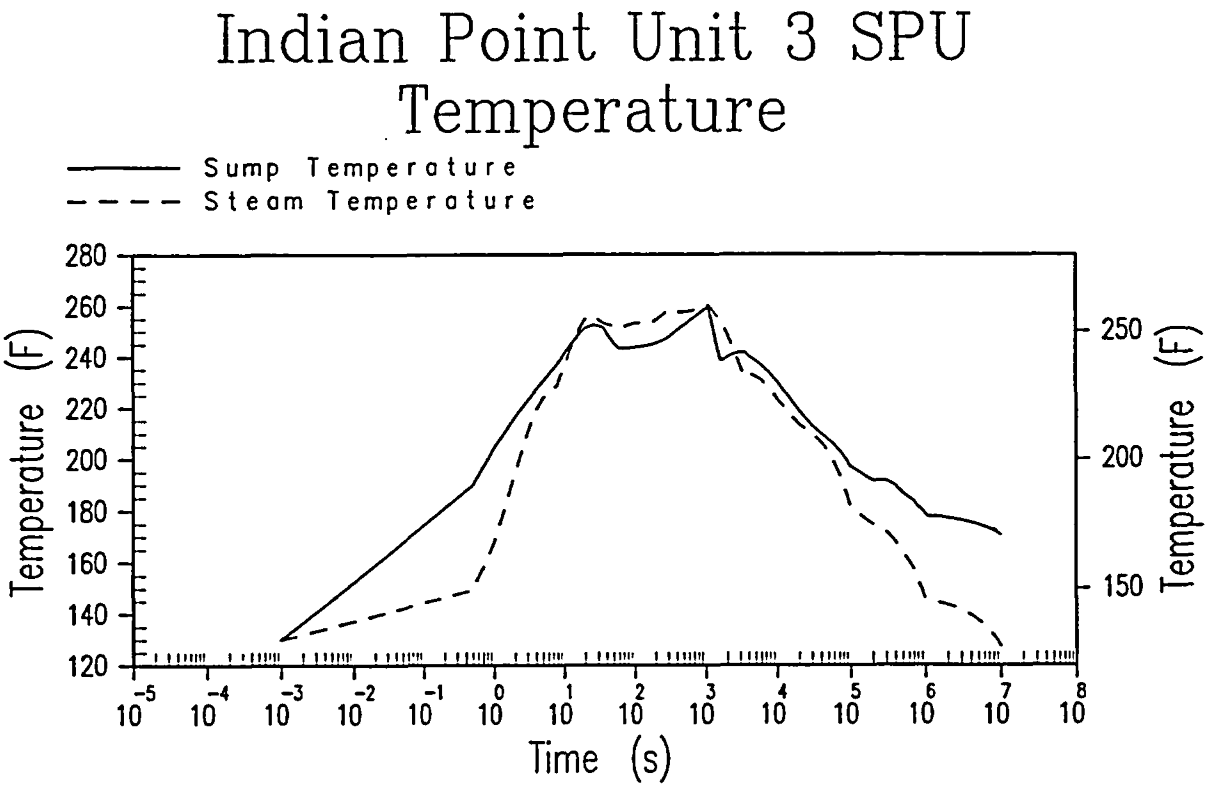


Figure 6.5-2

DEPS Break Minimum ECCS - Containment Temperature

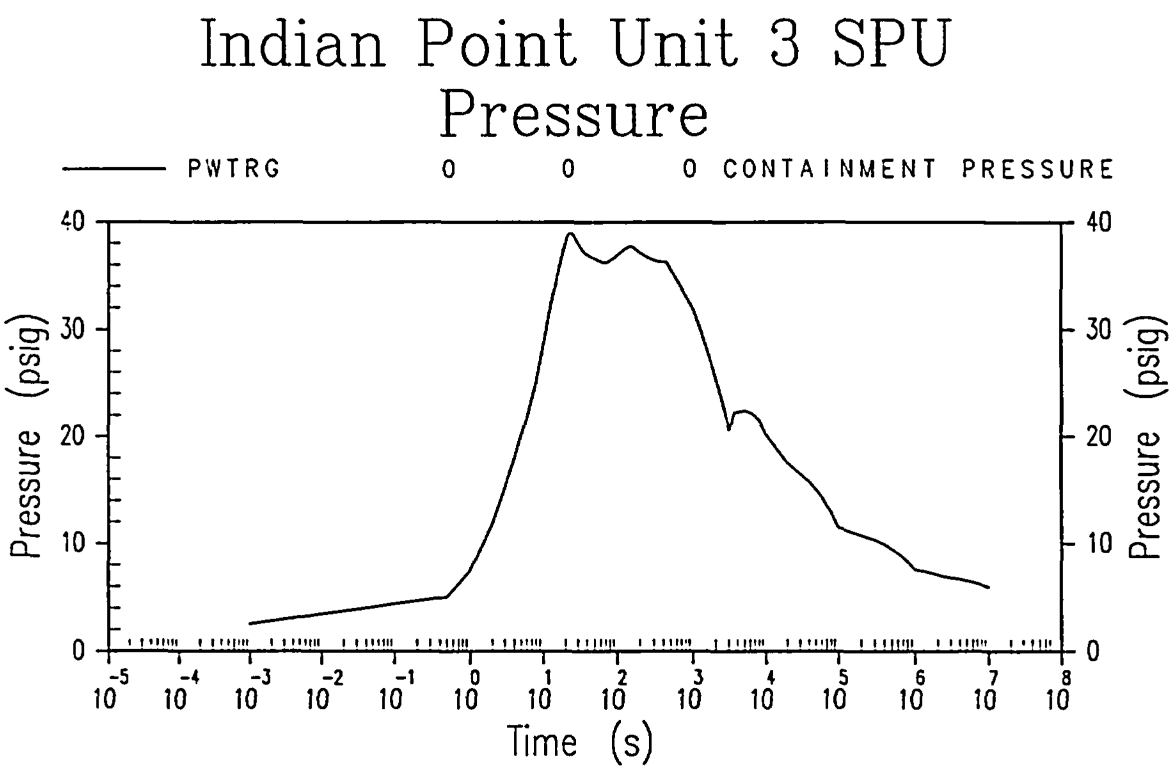


Figure 6.5-3

DEPS Break Maximum ECCS - Containment Pressure

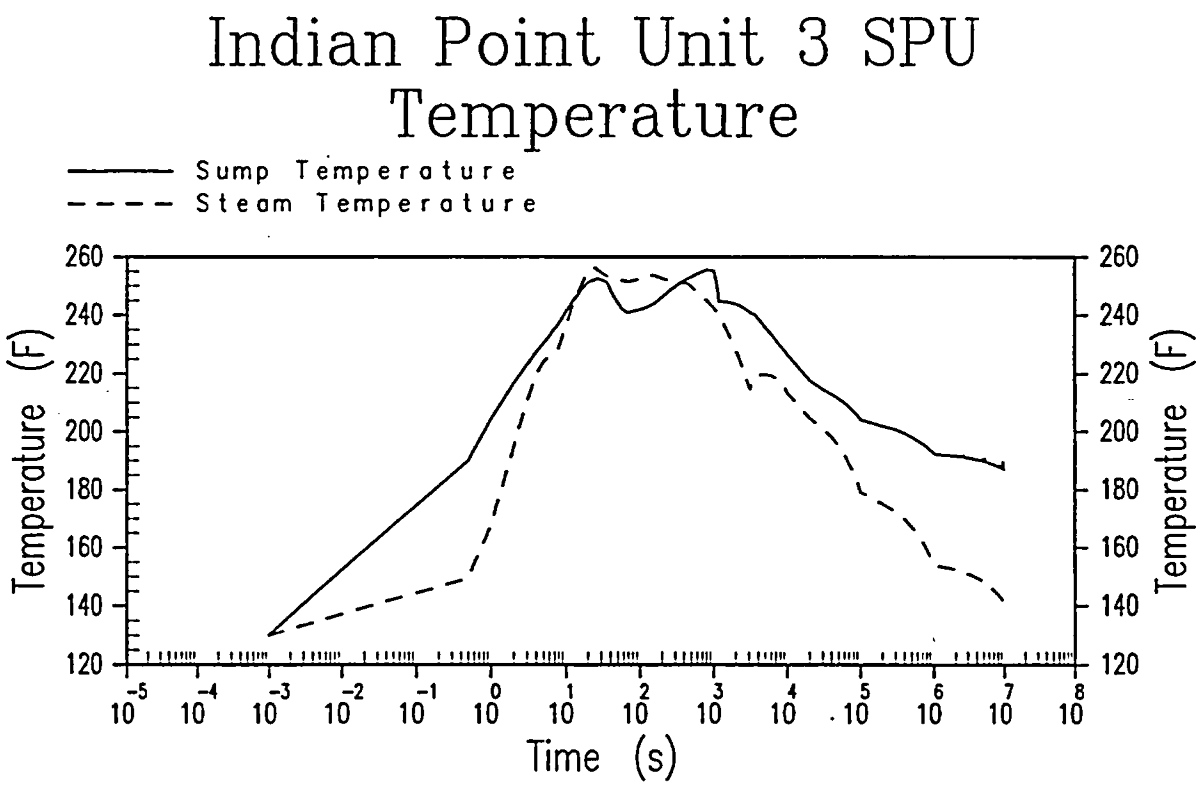


Figure 6.5-4

DEPS Break Maximum ECCS - Containment Temperature

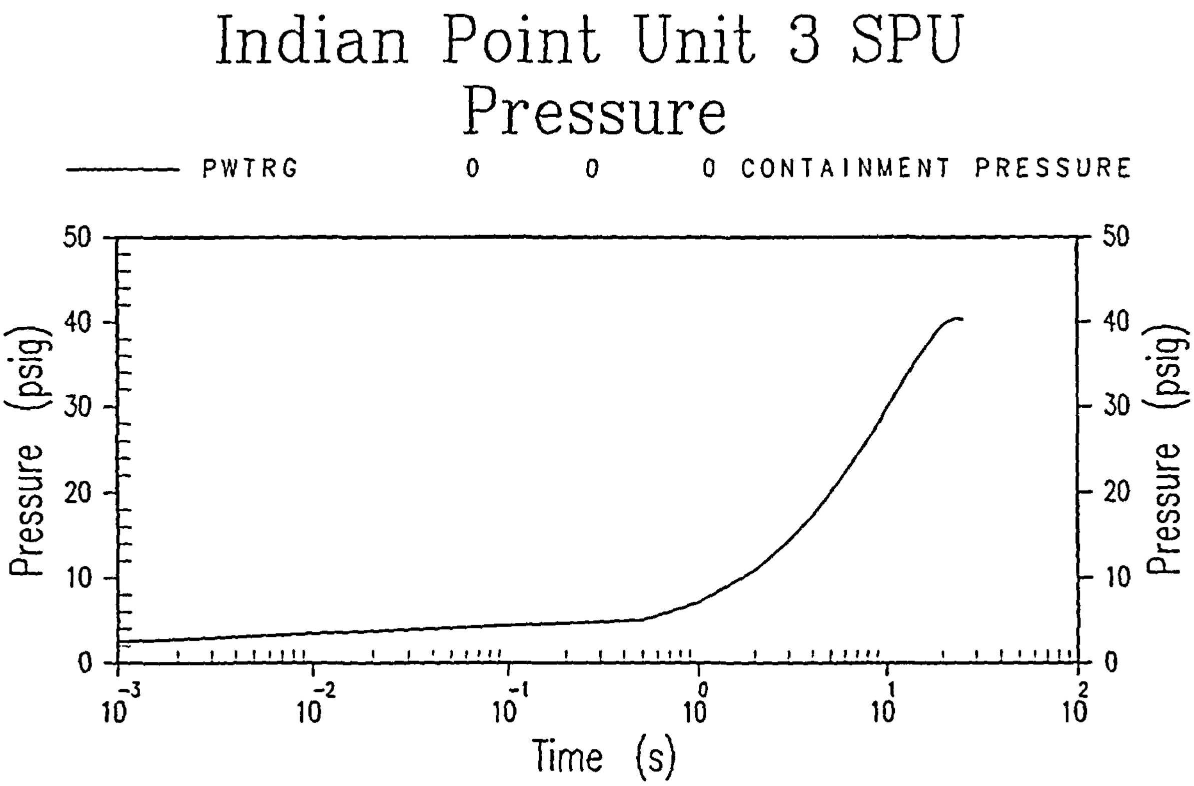


Figure 6.5-5

DEHL Break - Containment Pressure

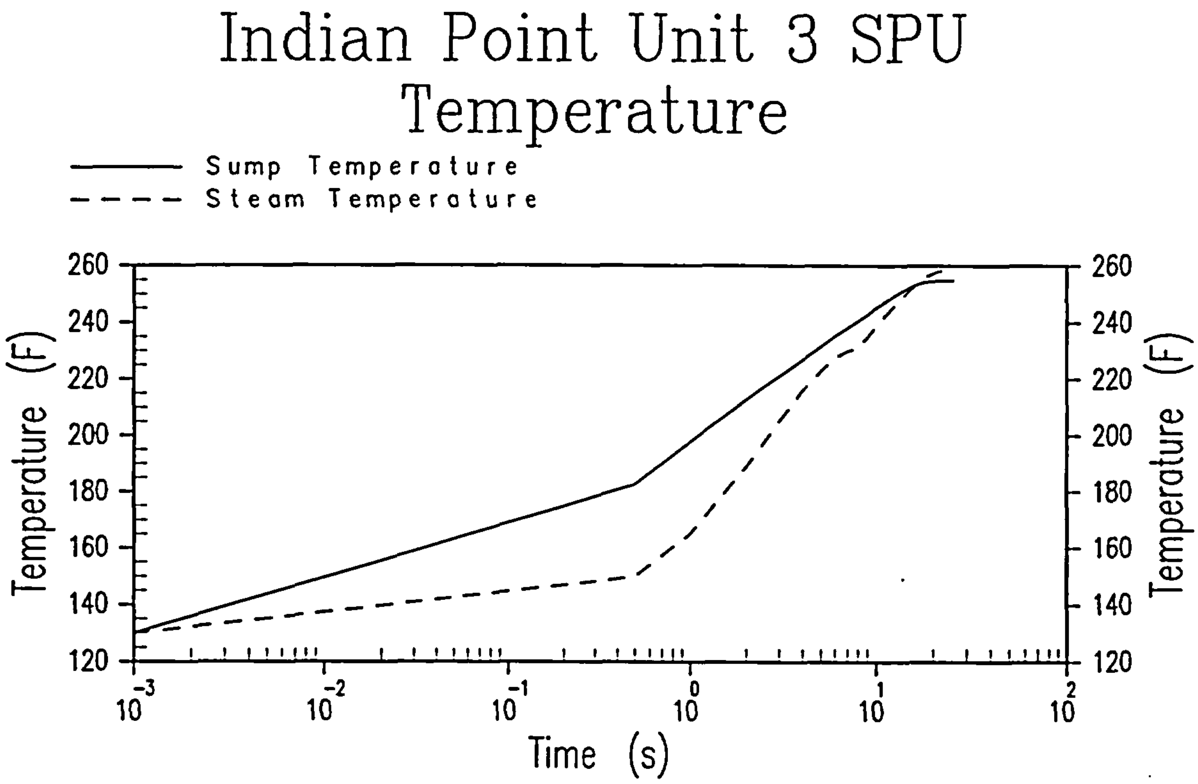


Figure 6.5-6

DEHL Break - Containment Temperature

6.6 Main Steamline Break Inside and Outside Containment

6.6.1 MSLB M&E Releases Inside Containment

6.6.1.1 Introduction

Steamline ruptures occurring inside a reactor containment structure may result in significant releases of high-energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steamline rupture is dependent upon the plant operating conditions, the size of the rupture, the configuration of the plant steam system, and containment building design. The analysis considers a postulated pipe break with limiting consequences, thereby encompassing wide variations in plant operation, safety system performance, and break size in determining the main steamline break (MSLB) mass and energy (M&E) releases for use in containment integrity analysis.

6.6.1.2 Input Parameters and Assumptions

To assess the effects of the M&E releases from a ruptured steamline, the limiting rupture of the main steamline has been evaluated. This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of Nuclear Steam Supply System (NSSS) power as the initiating condition for the MSLB event. At a plant power level of 102-percent nominal full-load power, a full double-ended rupture (DER) has been analyzed based on the results of the analyses presented in Section 14 of the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 1).

The DER is postulated in one steamline downstream of the steam generator flow restrictor. Note that a DER is defined as a rupture in which the steam pipe is severed and the ends of the break completely displace from each other. The effective break area for IP3 (with Westinghouse Model 44F steam generators) is 1.4 ft^2 because the flow from the steam generator is limited by the steam generator flow restrictor.

The important plant conditions and features that were assumed for the stretch power uprate (SPU) analysis case are discussed in the following paragraphs.

Initial Power Level

This analysis returns to the assumption of a 2-percent power uncertainty by assuming 102 percent of NSSS power as the initiating condition for the MSLB event. Full-power conditions have been investigated for IP3 as presented in the UFSAR (Reference 1).

NSSS power is used in this analysis since the reactor coolant pumps (RCPs) continue to run during the event. Net heat addition is conservatively modeled at 20 MWt (see Table 6.6-1). For the MSLB analysis, it has been demonstrated that the containment response at SPU conditions does not exceed the containment pressure limit of 42.42 psig, as delineated in the *Technical Specifications.*

Initial Plant Conditions

In general, plant initial conditions are assumed to be at their nominal values corresponding to the initial power for that case, with appropriate uncertainties included. Tables 6.6-1 and 6.6-2 identify the values assumed for Reactor Coolant System (RCS) pressure, RCS vessel average temperature, pressurizer water volume, steam generator water level, and feedwater enthalpy at 102-percent uprated power. Steamline break M&E releases assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window.

Single-Failure Assumptions

The analyzed case considered a single failure of the feedwater control valve (FCV) in the faulted loop. If the FCV in the feedwater line to the faulted steam generator is assumed to fail in the open position, there is a longer period of pumped feedwater flow and the unisolatable volume of feedwater piping is increased. The fluid inventory in this additional unisolatable feedwater piping is available to flash, entering the steam generator as the feedline depressurizes.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture typically results in large amounts of water being added to the faulted steam generator through the Main Feedwater System. The FCV is a rapid-closing valve that can limit this effect. However, as noted above, it is postulated to fail open in this analysis.

Following initiation of the MSLB, main feedwater flow is conservatively modeled as increasing in response to the decreasing steam pressure. This maximizes the total mass addition prior to feedwater isolation. Following the safety injection (SI) signal, the main feedwater pumps trip. However, condensate pumps continue to run, pumping a reduced feedwater flowrate into the faulted steam generator until the main feedwater pump discharge (BFD-2) valves close 122 seconds after the SI signal.

Following the termination of pumped feedwater, as the steam generator pressure decreases, the fluid in the feedwater lines downstream of the BFD-2 valves will flash when saturated conditions are reached in the feedwater piping. The flashing decreases the density of the feedwater, causing it to enter the faulted steam generator. This additional source of fluid is limited by the closure of the BFD-5 valve in the loop-specific feedline 125 seconds after the SI signal. The BFD-5 valve closure reduces the unisolatable feedline volume and thus limits the additional feedwater mass that enters the faulted steam generator.

Auxiliary Feedwater System

Addition of auxiliary feedwater (AFW) to the steam generators will increase the secondary mass available for release to containment and increase the heat transferred to the secondary fluid. Within the first minute following a steamline break, the Auxiliary Feedwater System (AFWS) is initiated on any one of several protection system signals. The AFW flow to the faulted and intact steam generators has been assumed to be a constant value, based on maximum AFW pump performance. A higher AFW flowrate to the faulted loop steam generator is assumed, consistent with a depressurizing steam generator. Conversely, a lower AFW flowrate to the intact steam generators is assumed, consistent with the intact-loop steam generators remaining at a pressurized condition.

Steam Generator Secondary Side Fluid Mass

A maximum initial steam generator mass in the faulted-loop steam generator was used in the analyzed case. The use of a high faulted-loop initial steam generator mass maximizes the steam generator inventory available for release to containment. The initial mass was calculated as the value corresponding to the programmed level +10-percent narrow-range span (NRS) and assuming 0-percent steam generator tube plugging (SGTP), plus an uncertainty on steam generator water mass.

Steam Generator Reverse Heat Transfer

Once the steamline isolation is complete, the steam generators in the intact loops become sources of energy, which can be transferred to the steam generator with the broken line. This energy transfer occurs via the primary coolant. When the RCS fluid temperature decreases below the secondary side intact steam generator fluid temperature, energy is returned to the primary coolant. This energy is then available for transfer to the steam generator with the broken steamline. The effects of reverse steam generator heat transfer are included in the results.

Break Flow Model

Piping discharge resistances were not included in the calculation of the releases resulting from the steamline ruptures (Moody Curve for an f [L/D] = 0 was used).

Steamline Volume Blowdown

The contribution to the M&E releases from the secondary plant steam piping was included in the M&E release calculations. For the analyzed case, the steamline check valves were credited to prevent break flow from the intact steam generators. Therefore, the M&E available for release from the secondary plant steam piping is limited to that contained in the volume between the faulted steam generator and the steamline check valve. The flowrate was determined using the Moody critical mass flow model.

Main Steamline Isolation

Steamline isolation is not considered, as the steamline check valve in the faulted loop is credited to prevent blowdown from the three intact steam generators.

Protection System Actuations

The protection systems available to mitigate the effects of a MSLB accident inside containment include reactor trip, safety injection, steamline isolation, and feedwater isolation. (Subsequent analysis of the containment response to the MSLB models the operation of the emergency fan coolers and containment spray.) The protection system actuation signals and associated setpoints that were modeled in the analysis are identified in Table 6.6-3. The setpoints used are conservative with respect to the IP3 plant-specific values presented in the *Technical Specifications* (Reference 2).

For the DER MSLB for IP3 at 102-percent power, the first protection system signal actuated is high-1 containment pressure, which initiates safety injection; the SI signal produces a reactor trip signal. Feedwater system isolation occurs as a result of the SI signal.

Safety Injection System

Minimum Emergency Core Cooling System (ECCS) flowrates corresponding to the failure of one ECCS train were assumed in this analysis. A minimum ECCS flow is conservative since the reduced boron addition maximizes a return to power resulting from RCS cooldown. The higher power generation increases heat transfer to the secondary side, maximizing steam flow out of the break. The delay time to start ECCS pumps was assumed to be 16 seconds for this

analysis with offsite power available. A coincident loss-of-offsite power (LOOP) is not assumed for the analysis since the assumed LOOP would reduce the M&E releases. This is due to the loss-of-forced reactor coolant flow, which results in a consequential reduction in primary-to-secondary heat transfer.

RCS Metal Heat Capacity

As the primary side of the plant cools, the temperature of the reactor coolant drops below the temperature of the reactor coolant piping, the reactor vessel, and the RCPs. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major effect on the calculated M&E releases. The effects of this RCS metal heat are included in the results using conservative thick-metal masses and heat-transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating the steamline break M&E releases was based on the 1979 American National Standard (ANS) decay heat with 2σ uncertainty model (Reference 3).

Rod Control

The Rod Control System was conservatively assumed to be in manual operation for all steamline break analyses. Rods in automatic control would step into the core prior to reactor trip, due to the increased steam flow. This would reduce nuclear power and core heat flux, reducing the primary-to-secondary heat transfer.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to end-of-cycle (EOC) conditions were used to maximize the reactivity feedback effects resulting from the steamline break. Use of maximum reactivity feedback results in higher power generation if the reactor returns to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

6.6.1.3 Description of Analysis

The break flows and enthalpies of the steam release through the steamline break inside containment are analyzed with the LOFTRAN computer code (Reference 4). Blowdown M&E releases determined using LOFTRAN include the effects of core power generation, main and

AFW additions, engineered safeguards systems, RCS thick metal heat storage, and reverse steam generator heat transfer.

The IP3 NSSS is analyzed using LOFTRAN to determine the transient steam M&E releases inside containment following a steamline break event. The M&E releases are used as input conditions to the analysis of the containment response.

The licensing-basis cases of the MSLB inside containment that have been analyzed for the SPU are the full DER at 102-percent power and the full DER at 70-percent power, both with the FCV in the faulted loop assumed to be failed open. Selection of these cases was based on the results of the analyses presented in the IP3 UFSAR, Section 14 (Reference 1).

For the DER cases, the forward-flow cross-sectional area from the faulted-loop steam generator is limited by the integral flow restrictor area of 1.4 ft^2 for IP3 (Model 44F steam generators). Reverse flow from the three intact steam generators is prevented by the steamline check valve located downstream of the break site.

6.6.1.4 Acceptance Criteria

The MSLB is classified as an ANS Condition IV event—an infrequent fault. Additional clarification of the ANS classification of this event is presented in subsection 6.3.11 of this report, which discusses the core response to a steamline break event. The acceptance criterion associated with the steamline break event resulting in an M&E release inside containment is not based on the M&E analysis itself. It is based on an analysis for containment response that provides sufficient conservatism to ensure that the containment design margin is maintained. The containment response analysis is discussed in subsection 6.6.2.

The specific criterion applicable to this analysis is related to the assumptions regarding power level, stored energy, the break flow model including entrainment, main and auxiliary feedwater flow, steamline and feedwater isolation, and single failure such that the containment peak pressure and temperature are maximized. These analysis assumptions have been included in this steamline break M&E release analysis as discussed in Reference 5 and subsection 6.6.1.2 of this report.

The M&E release data for each of the MSLB cases were used as input to a containment response calculation to confirm the design parameters of the IP3 containment structure.

6.6.1.5 Results

Using the UFSAR (Reference 1) as a basis, including parameter changes associated with the SPU, the M&E release rates for the MSLB case noted in subsection 6.6.1.3 were developed for use in containment pressure and temperature response analysis. The containment pressure response was, in turn, used for evaluation of containment integrity. Table 6.6-4 provides the sequence of events for IP3, for the large DER at 102-percent power and 70-percent power with feedwater control valve failure assumed.

6.6.1.6 Conclusions

The M&E releases from the MSLB case have been analyzed at the SPU power conditions. The assumptions discussed in subsection 6.6.1.2 have been included in the MSLB analysis such that the applicable acceptance criteria are met. The M&E releases discussed in this section have been provided for use in the containment response analysis (see subsection 6.6.2) in support of the IP3 SPU.

6.6.2 Steamline Break Containment Response Evaluation

6.6.2.1 Introduction

The IP3 containment systems are designed such that for all steamline break sizes, up to and including the double-ended severance of a steamline, the containment peak pressure remains below the design pressure. This section details the containment response subsequent to a hypothetical steamline break. The containment response analysis uses the long-term M&E release data from subsection 6.6.1.5.

6.6.2.2 Input Parameters and Assumptions

The pressure, temperature, and humidity of the containment atmosphere prior to the postulated accident are specified in the analysis as shown in Table 6.6-5.

Also, values for the refueling water storage tank (RWST) temperature have been specified, along with containment spray (CS) pump flowrate and reactor containment fan cooler (RCFC) heat removal performance. These values are chosen conservatively, as shown in Tables 6.6-5, 6.6-6 and 6.6-7. The heat sink modeling is specified in Tables 6.6-8 and 6.6-9, and is consistent with the values used for the LOCA containment response analysis, as documented in Section 6.5 of this document.

Subsection 6.6.1.5 discusses the M&E releases for the SPU MSLB case. The M&E release analysis includes the single failure of the faulted-loop FCV, as discussed in subsection 6.6.1.2. Since a single failure is included in the M&E release analysis, no single failure is modeled in the containment response analysis.

6.6.2.3 Description of Analysis

Calculation of containment pressure and temperature is accomplished by using the computer code COCO (Reference 6). COCO is a mathematical model of a generalized containment; the proper selection of various options in the code allows the creation of a specific model for a particular containment design. The values used in the specific model for different aspects of the containment are derived from plant-specific input data. The COCO code has been used and found acceptable to calculate containment pressure and temperature transients for previous IP3 containment response analyses.

6.6.2.4 Acceptance Criteria

The design basis MSLB is an ANS Condition IV event—an infrequent fault. To satisfy the NRC acceptance criteria presented in the IP3 UFSAR, Revision 18 (Reference 1) for long-term containment response, the relevant General Design Criteria (GDC) (Reference 7) requirements are listed below.

GDC 16, Containment Design

To satisfy the requirements of GDC 16, the peak calculated containment pressure must be less than the containment design pressure of 47 psig for IP3. Additionally, the peak containment pressure must be less than the integrated leak rate test (ILRT) limit of 42.42 psig.

GDC 38, Containment Heat Removal

To satisfy the requirement of GDC 38, the calculated pressure at 24 hours must be less than 50 percent of the peak calculated value.

6.6.2.5 Analysis Results

The peak containment pressure is listed in Table 6.6-10 uprated full-power case with offsite power available. The containment pressure curves for 102- and 70-percent power steamline break are provided in Figures 6.6-1 and 6.6-2.

6.6.2.6 Conclusions

An evaluation of the MSLB containment pressure response has been performed as part of the IP3 SPU. The analysis included the long-term pressure profile for the limiting case. The analyzed case results in a peak containment pressure that is less than the containment design pressure of 47 psig, as well as below the ILRT limit of 42.42 psig. The long-term pressures are well below 50 percent of the peak value within 24 hours. Based on these results, the GDC criteria for IP3 have been met.

6.6.3 MSLB M&E Releases Outside Containment Responses

6.6.3.1 Introduction

MSLBs outside the Containment Building were considered for the IP3 SPU to define conditions for equipment qualification (EQ) for electrical equipment that is needed to mitigate the consequences of high-energy line breaks (HELBs) and is located near the steam and feed penetration area.

Steamline ruptures occurring outside the reactor containment structure may result in significant releases of high-energy fluid to the structures surrounding the steam systems. Superheated steam blowdowns following the steamline break have the potential to raise compartment temperatures outside containment. Early uncovery of the steam generator tube bundle maximizes the enthalpy of the superheated steam that is released. The effect of the steam release depends on the plant configuration at the time of the break, plant response to the break, and the size and location of the break. Because of the interrelationship among many of the factors that influence steamline break M&E releases, an appropriate determination of a single limiting case with respect to M&E releases cannot be made. Therefore, it was necessary to analyze the steamline break event outside containment for a range of conditions. The resulting M&E releases were used as input to the Auxiliary Building temperature analysis (see subsection 6.5.2.7) for equipment environmental qualification (see subsection 10.9.3 of this document).

6.6.3.2 Input Parameters and Assumptions

To determine the effects of NSSS power level and break area on M&E releases from a ruptured steamline, spectra of both variables were evaluated as part of the methodology development program documented in WCAP-10961 (Reference 8). At 102 and 70 percent of NSSS power levels, various break sizes were analyzed, ranging from 0.1 ft^2 to 4.6 ft^2.

A full-break spectrum at both power levels (102 and 70 percent) has been analyzed at the SPU conditions for IP3. Other assumptions regarding important plant conditions and features are discussed in the following paragraphs.

Initial Power Level

The initial power assumed for steamline break analyses outside containment affects the M&E releases and steam generator tube bundle uncovery in two ways. First, the steam generator mass inventory increases with decreasing power levels. This will tend to delay uncovery of the steam generator tube bundle, although the increased steam pressure at lower power levels will cause faster blowdown at the beginning of the transient. Second, the amount of stored energy and decay heat, as well as feedwater temperature, are less for lower power levels. This will result in lower primary temperatures and less primary-to-secondary heat transfer during the steamline break event.

Therefore, the following power levels were analyzed:

- Full power - maximum NSSS power (3230 MWt based on 3216 MWt plus 14 MWt for RCP heat addition) plus uncertainty, that is, 102 percent of rated NSSS power
- Near full-power - 70 percent of maximum NSSS power

For this IP3 SPU analysis, the power levels and steamline break sizes are noted in subsection 6.6.3.3 of this report.

In general, plant initial conditions were assumed to be the nominal values corresponding to the initial power for that case, with appropriate uncertainties included. Table 6.6-11 lists nominal 100-percent power NSSS conditions. Table 6.6-12 lists initial plant condition assumptions for the cases analyzed.

Steamline break mass releases and superheated steam enthalpies assuming an RCS average temperature at the high end of the T_{avg} window are conservative with respect to similar releases at the low end of the T_{avg} window. At the high end, the calculated values of the superheated steam enthalpy available for release outside containment are larger than at the low end. The thermal design flowrate has been used for the RCS flow input. This is consistent with the assumptions documented in Reference 5 and with other MSLB analysis assumptions related to nonstatistical treatment of uncertainties and RCS thermal-hydraulic inputs related to pressure drops and rod drop time.

Uncertainties on the initial conditions assumed in the analysis for the SPU have been applied only to RCS average temperature (7.5°F), steam generator mass (10-percent NRS), and power fraction (2 percent) at full power. Nominal values are adequate for the initial pressurizer pressure and water level. Uncertainty conditions were only applied to those parameters that could increase the enthalpy of superheated steam discharged from the break.

Single-Failure Assumptions

The steamline break analyses outside containment were designed to encompass the failure of one AFW pump and an additional conservative failure of the main steamline isolation valve (MSIV) in the loop with the faulted steamline.

The first single failure is one AFW pump resulting in minimum AFW flow to the steam generators. Variations in AFW flow can affect steamline break M&E releases in a number of ways, including break mass flowrate, RCS temperature, tube bundle uncovery time, and steam superheating. The minimum AFW flow used in the analysis was conservatively based on only one motor-driven AFW pump.

The second failure is the MSIV in the loop with the faulted steamline. This permits blowdown of the entire mass inventory of the steam generator in the loop with the faulted steamline. This failure was limited to the steamline with the postulated break.

Main Feedwater System

The rapid depressurization that occurs following a steamline rupture results in large amounts of water being added to the steam generators through the Main Feedwater System. However, main feedwater flow has been conservatively modeled by assuming no increase in feedwater flow in response to the increased steam flow following the steamline break. This minimizes total mass addition and the associated cooling effects in the steam generators, which causes the earliest onset of superheated steam released from the break.

Isolation of main feedwater flow was conservatively assumed to be coincident with reactor trip, irrespective of the function that produced the trip signal. This assumption reduces the total mass addition to the steam generators. The main feedwater flow isolation valves were assumed to close instantaneously with no consideration of associated signal processing or valve stroke time.

Auxiliary Feedwater System

Within the first few minutes following a steamline break, AFW is initiated on one of several protection system signals. Addition of AFW to the steam generators will increase the secondary mass available to cover the tube bundle and reduce the amount of superheated steam produced. For this reason, AFW flow is minimized while the actuation delay is maximized to accentuate depletion of the initial secondary side inventory.

The volume of the AFW piping up to the isolation valve closest to the steam generator was maximized and purging of the AFW piping was assumed. This maximizes the amount of preheated water resident in the AFW piping and ensures that this preheated water was injected into the steam generator first. The less dense resident AFW decreases initial mass addition to the faulted-loop steam generator. The large volume also delays the introduction of colder AFW into any steam generator, which reduces the cooldown effect on the primary side of the RCS. AFW assumptions used in the analysis are presented in Table 6.6-13.

Steam Generator Fluid Mass

A minimum initial fluid mass in all steam generators has been used in each of the analyzed cases. This minimizes the capability of the heat sink afforded by the steam generators and leads to earlier tube bundle uncovery. The initial mass has been calculated as that corresponding to the programmed water level, minus 10-percent NRS, minus a mass uncertainty. All steam generator fluid masses were calculated assuming 0-percent SGTP. This assumption is conservative with respect to the RCS cooldown through the steam generators resulting from the steamline break.

Steam Generator Reverse Heat Transfer

Once steamline isolation is complete, the steam generators in the intact loops become sources of energy that can be transferred to the steam generator with the broken steamline via the primary coolant. When the RCS fluid temperature decreases below the secondary side intact steam generator fluid temperature, energy is returned to the primary coolant. This energy is then available to be transferred to the steam generator with the broken steamline. When applicable, the effects of reverse steam generator heat transfer were included in the results.

Break Flow Model

The flow rate from the break is maximized by assuming a critical flow rate for saturated steam based on the Moody correlation for f[L/D]=0. The upstream pressure is based on the steam generator pressure, with no credit for line losses or piping discharge resistance. The downstream pressure is assumed to be atmospheric throughout the blowdown.

Steamline Volume Blowdown

There is no contribution to M&E releases from the steam in the secondary plant loop piping and header because the initial volume is saturated steam. With the focus of the MSLB analysis outside containment on maximizing superheated steam enthalpy, it is presumed that the saturated steam in the loop piping and header has no adverse effects on the results. The blowdown of steam in this volume serves to delay the time of tube uncovery in the steam generators and is conservatively ignored.

Main Steamline Isolation

Steamline isolation was assumed to terminate blowdown from the intact-loop steam generators for the header break cases. The main steamline isolation function was accomplished via the closure of the MSIVs on the intact loops. The MSIV actuation signal is generated if the following setpoints are reached in at least two loops:

- Low steamline pressure coincident with high steam flow, or
- Low-low T_{avg} coincident with high steam flow.

A delay time of 7 seconds, accounting for delays associated with signal processing plus MSIV stroke time, has been assumed. Unrestricted steam flow through the valve during valve stroke has been assumed. Operator action to close MSIVs is credited at 600 or 900 seconds if the setpoints for steamline isolation are not reached. The Analysis of Record assumed an operator action time of 600 seconds.

For loop break cases, the faulted-loop steamline check valve was assumed to prevent blowdown from the three intact steam generators. Closure of the MSIVs does not have an impact on the loop break cases in the analysis.

Protection System Actuations

The protection systems available to mitigate the effects of a MSLB outside containment include reactor trip, SI, steamline isolation, and AFW injection. The protection system actuation signals

and associated setpoints that were modeled in the analysis are identified in Table 6.6-14. The setpoints are conservative values with respect to the plant-specific values delineated in the IP3 *Technical Specifications* (Reference 2).

Tables 6.6-15 through 6.6-22 provide the protection system actuation times for the various steamline break sizes for IP3, at 102- and 70-percent NSSS power.

In all cases, the turbine stop valve was assumed to close instantly following the reactor trip signal.

Safety Injection System

Minimum ECCS flowrates corresponding to failure of one ECCS train have been assumed in this analysis. Minimum ECCS flow is conservative since the reduced boron addition maximizes a return to power resulting from RCS cooldown. The return to power increases heat transfer to the secondary side, maximizing steam flow from the break. The delay time to achieve full SI flow was assumed to be 15 seconds for this analysis with offsite power available. A coincident LOOP was not assumed for the analysis since the M&E releases would be reduced due to loss-of-forced reactor coolant flow, resulting in less primary-to-secondary heat transfer.

RCS Metal Heat Capacity

As the primary side of the plant cools, the reactor coolant temperature drops below that of the reactor coolant piping, reactor vessel, RCPs, and steam generator thick-metal mass and tubing. As this occurs, the heat stored in the metal is available to be transferred to the steam generator with the broken line. Stored metal heat does not have a major effect on the calculated M&E releases, but the effects were included in the results using conservative thick-metal masses and heat transfer coefficients.

Core Decay Heat

Core decay heat generation assumed in calculating steamline break M&E releases was based on the 1979 ANS decay heat with 2σ uncertainty model (Reference 3).

Rod Control

The Rod Control System was conservatively assumed to be in manual operation for all steamline break analyses. Rods in automatic control would step in prior to reactor trip due to the increase in steam flow, reducing nuclear power and core heat flux. However, sensitivity analyses performed when WCAP-10961 (Reference 8) was written, investigating the effects on

steamline break M&E releases of manual versus automatic rod control, have shown negligible effect on calculated results.

Core Reactivity Coefficients

Conservative core reactivity coefficients corresponding to EOC conditions were used to maximize reactivity feedback effects resulting from the steamline break. This results in higher power generation should the reactor return to criticality, thus maximizing heat transfer to the secondary side of the steam generators.

6.6.3.3 Description of Analysis

The system transient that provides the break flows and enthalpies of the steam release through the steamline break outside containment has been analyzed with the LOFTRAN (Reference 4) computer code. Blowdown M&E releases determined using LOFTRAN include the effects of core power generation, main feedwater and auxiliary feedwater additions, engineered safeguards systems, RCS thick-metal heat storage, and reverse steam generator heat transfer. The use of the LOFTRAN code for analysis of the MSLB with superheated steam M&E releases is documented in Supplement 1 of WCAP-8822 (Reference 5), which has been reviewed and approved by the NRC for use in analyzing MSLBs. LOFTRAN was also used in WCAP-10961 (Reference 8) for MSLBs outside containment.

The IP3 NSSS has been analyzed to determine the transient mass releases and associated superheated steam enthalpy values outside containment following a steamline break event. The resulting tables of mass flowrates and steam enthalpies were used as input conditions to the calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment.

The following cases of the MSLB outside containment were analyzed at the noted conditions for the SPU.

- At 102-percent power, break sizes of 4.6, 2.0, 1.4, 1.2, 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2

- At 70-percent power, break sizes of 4.6, 2.0, 1.4, 1.2, 1.0, 0.9, 0.8, 0.7, 0.6, 0.5, 0.4, 0.3, 0.2, and 0.1 ft^2

Each MSLB outside containment was represented as a non-mechanistic split rupture (crack area). The largest break was postulated as a crack area equivalent to a single-ended pipe rupture. The break flowrate was limited by the total cross-sectional flow area of the steam pipe;

the maximum break size was limited to the header break size of 4.6 ft^2. Prior to steamline isolation, the break area was represented by the spectrum noted above. After steamline isolation, the break area was limited by the area of the integral steam generator flow restrictor (1.4 ft^2).

6.6.3.4 Acceptance Criteria

The acceptance criteria associated with the steamline break event resulting in an M&E release outside containment are based on an analysis that provides sufficient conservatism to ensure that the equipment remains qualified for the temperature and pressure profiles from the compartment analyses. The specific criteria applicable to this analysis are related to the assumptions regarding power level, stored energy, break flow model, steamline and feedwater isolation, and main and auxiliary feedwater flow such that superheated steam resulting from tube bundle uncovery in the steam generators is accounted for and maximized. These assumptions have been included in this steamline break M&E release analysis as discussed in subsection 6.6.3.2 of this report. The tables of mass flowrates and steam enthalpy values for each of the steamline break cases analyzed were used as input to calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment.

6.6.3.5 Results

Using the MSLB analysis methodology documented in WCAP-10961 (Reference 8) as a basis, including parameter changes associated with the SPU, the M&E release rates for each steamline break case have been developed for use in calculating outside-containment compartment conditions for the environmental evaluation of safety-related electrical equipment. Tables 6.6-15 through 6.6-22 provide the sequences of events for the various steamline break sizes for IP3, at 102- and 70-percent NSSS power.

6.6.3.6 Conclusions

The mass releases and associated steam enthalpy values from the spectrum of steamline break cases outside containment have been analyzed at the conditions defined by the IP3 SPU. The assumptions discussed in subsection 6.6.3.2 have been included in the analysis such that conservative M&E releases were calculated. The resulting mass releases and associated steam enthalpy values have been provided for use in the calculation of outside-containment compartment conditions (see subsection 6.6.4) for the environmental evaluation of safety-related electrical equipment outside containment in support of the IP3 SPU.

6.6.4 MSLB Outside Containment Compartment Response

6.6.4.1 Introduction

This section of the report presents the results of a study to determine the effects of superheated steam releases, during postulated main steamline ruptures, on outside containment equipment qualification for IP3. For this study, the compartment temperature profiles for the steam and feed penetration area were calculated as required by 10CFR50.49 (Reference 9).

NRC IE Information Notice 84-90, *Main Steam Line Break Effect on Environmental Qualification of Equipment*, (Reference 10) informed licensees of potential issues related to the release of superheated steam following a postulated MSLB. Specifically, such superheated blowdowns have the potential to raise the compartment temperatures and, therefore, the equipment surface and internal temperatures, above those originally used for the environmental qualification of such equipment needed to mitigate the consequences of HELBs.

The report describes the methods and assumptions used in modeling the IP3 compartments in the steam and feed penetration area. The M&E releases from the postulated MSLBs were discussed in subsections 6.6.3.1 through 6.6.3.6. The results from these calculated compartment temperature profiles are discussed here.

6.6.4.2 Input Parameters and Assumptions

This study used MSLB M&E releases (see subsections 6.6.3.1 through 6.6.3.6) in calculations of the outside containment compartment temperatures resulting from those releases. The RCS conditions used for determining the steamline break M&E releases were described in subsection 6.6.3.2. The compartment model was developed for the GOTHIC code (Reference 11) from engineering drawings and plant information.

Some ventilation louvers in the steam and feed penetration area are closed and covered during winter conditions. Because of this difference and because of the different temperature and humidity conditions for winter and summer, cases were divided into winter and summer conditions. Table 6.6-23 provides the GOTHIC initial conditions for the winter and summer cases.

6.6.4.3 Description of Analysis

This analysis of the temperature and pressure response in the steam and feed penetration area was performed with the GOTHIC code. The M&E releases for loop breaks at 102- and 70-percent power and header breaks at 102- and 70-percent power were provided by the

analysis discussed in subsections 6.6.3.1 through 6.6.3.6 at the SPU conditions. The compartment response was determined for two sets of initial temperature conditions, winter and summer. In addition to the initial temperature and relative humidity, the cases for the winter and summer conditions also modeled several louvers differently. The louvers were modeled as closed for both the winter and summer conditions, but for the winter, Entergy covers the louvers in order to reduce the possibility of freezing in the compartment. The compartment response for limiting breaks was calculated for a period of 30,000 seconds. This duration was sufficient to ensure that the compartment and component (thermal lag) temperatures decrease to below the initial conditions.

6.6.4.4 Acceptance Criteria

The acceptance criteria for the outside containment compartment temperature evaluation was defined for the EQ program at IP3 as the qualification limits for each piece of equipment because each piece of equipment has its own qualification conditions. The peak temperature in the compartment and the duration at elevated temperatures are of interest for the EQ program. (Refer to subsection 10.9.3 of this report for the EQ discussion.)

6.6.4.5 Results

The M&E releases for IP3 were provided by the analysis in subsections 6.6.3.1 through 6.6.3.6 at the SPU conditions.. These cases were analyzed for IP3 at initial conditions for winter and initial conditions for summer.

The computer simulations performed for the M&E release analysis were run assuming operator action times of 600 and 900 seconds to terminate AFW flow and close the MSIVs. The limiting winter break was a 1.2-ft^2 header break at 102-percent power, which generated a peak area temperature of about 481°F and the limiting summer break was a 1.4-ft^2 header break at 102-percent power, which generated a peak area temperature of about 484°F. The area temperatures returned to near initial conditions within 4 hours for the bounding winter case, and 3 hours for the bounding summer case.

6.6.4.6 Conclusions

Since these results were used for EQ, the temperature and pressure profiles for each case were provided for the EQ evaluations.

The limiting temperature profile and corresponding pressure profiles for the 600-second (10-minute) operator action time are provided in Figures 6.6-3 and 6.6-4 for winter and summer conditions. The limiting temperature profile and corresponding pressure profile for the 900-second (15-minute) operator action time are provided in Figures 6.6-5 and 6.6-6 for winter and summer conditions. Section 10.9.3 of this report uses the individual case profiles to address the qualification of the equipment for IP3 at the SPU conditions.

6.6.5 Steam Releases for Radiological Dose Analysis

The vented steam releases have been calculated for the locked rotor and steamline break events. Table 6.6-24 summarizes the vented steam releases from the operable steam generators as well as auxiliary feedwater flows for the 0- to 2-hour time period, and the 2- to 29-hour time period for each of these events.

The steam releases discussed in this section have been provided as inputs to the radiological dose analyses (see subsection 6.11.9) in support of the IP3 SPU.

6.6.6 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

2. *Indian Point Unit 3 Technical Specifications, Amendment 205.*

3. ANSI/ANS-5.1-1979, *American National Standard for Decay Heat Power in Light Water Reactors*, The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, August 1979.

4. WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Nonproprietary), *LOFTRAN Code Description*, T. W. T. Burnett, et al., April 1984.

5. WCAP-8822 (Proprietary) and WCAP-8860 (Nonproprietary), *Mass and Energy Releases Following a Steam Line Rupture*, September 1976; WCAP-8822-S1-P-A (Proprietary) and WCAP-8860-S1-A (Nonproprietary), *Supplement 1 – Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture*, September 1986; WCAP-8822-S2-P-A (Proprietary) and WCAP-8860-S2-A (Nonproprietary), *Supplement 2 – Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs*, September 1986.

6. WCAP-8327 (Proprietary), WCAP-8326 (Nonproprietary), *Containment Pressure Analysis Code (COCO), July 1974.*

7. 10CFR50 Appendix A, *General Design Criteria for Nuclear Power Plants.*

8. WCAP-10961 (Proprietary), *Steamline Break Mass/Energy Releases for Equipment Environmental Qualification Outside Containment, Report to the Westinghouse Owners Group High Energy Line Break/Superheated Blowdowns Outside Containment Subgroup*, Rev. 1, October 1985.

9. 10CFR50.49, *Environmental Qualification Of Electric Equipment Important To Safety For Nuclear Power Plants*, 66FR64738, December 14, 2001.

10. NRC IE Information Notice 84-90, *Main Steam Line Break Effect on Environmental Qualification of Equipment*, December 07, 1984.

11. NAI 8907-02, *GOTHIC Containment Analysis Package User Manual*, Version 7.1, Rev. 14, January 2003.

Table 6.6-1 Nominal Plant Parameters for IP3 SPU[1] (MSLB M&E Releases Inside Containment)	
Nominal Conditions	**IP3**
NSSS Power, MWt	3230
Core Power, MWt	3216
Net Heat Addition, MWt	20[2]
Reactor Coolant Flow (total), gpm	354,400
Pressurizer Pressure, psia	2250
Core Bypass, %	5.5 – 7.5
Reactor Coolant Temperatures, °F	
Core Outlet	607.5
Vessel Outlet	603.0
Core Average	575.8
Vessel Average	572.0
Vessel/Core Inlet	541.0
Steam Generator	
Steam Temperature, °F	516.3
Steam Pressure, psia	787
Steam Flow (total), 10^6 lbm/hr	14.01
Feedwater Temperature, °F	433.6

Note:

1. Noted values correspond to plant conditions defined for 0% SGTP and the high end of the RCS T_{avg} window.
2. 14 MWt RCP heat addition was used for MSLB M&E analyses to determine NSSS power. A net heat addition of 20 MWt is conservatively assumed as additional energy that must be released through the faulted steam generator.

Table 6.6-2

IP3

Initial Condition Assumptions for SPU[1]

MSLB M&E Releases Inside Containment	
Parameter	**Value**
NSSS Power (% Nominal Uprated)	102
RCS Average Temperature (°F)	579.5
RCS Flowrate (gpm)	354,400
RCS Pressure (psia)	2250
Pressurizer Water Volume (ft^3)	916.7 (102% Power) 777.23 (70% Power)
Feedwater Enthalpy (Btu/lbm)	412.3 (102% Power) 377.3 (70% Power)
SG Water Level (% span)	55

Note:

1. Noted values correspond to plant conditions defined for 0% SGTP and the high end of the RCS T_{avg} window; the temperature includes the applicable calorimetric uncertainties.

Table 6.6-3

Protection System Actuation Signals and Safety System Setpoints for IP3 SPU Analysis

MSLB M&E Releases Inside Containment	
Safety Injection High-1 Containment Pressure: 5.12 psig	Conservatively high value used SI signal results in reactor trip, feedwater isolation, and actuation of the RCFCs
Containment Sprays High-High Containment Pressure: 24.62 psig	Conservatively high value used

Table 6.6-4

1.4 ft² MSLB With FCV Failure Assumed
Sequence of Events for IP3 SPU

Time (sec)		
102% Power	70% Power	Event Description
0.0	0.0	MSLB occurs
4.0	3.8	SI setpoint reached on high-1 containment pressure
5.0	5.0	SI setpoint (high-1 containment pressure) credited in mass/energy calculation Start of AFW
7.0	7.0	Rod motion starts (high containment pressure actuates SI, which initiates reactor trip) Intact loop FCVs close
12.0	12.0	Main feedwater pumps trip
22.0	22.0	MFW pumps stopped; continued flow from condensate pumps
42.2	42.0	Fan coolers start
129.0	129.0	BFD-2 feedwater pump discharge valve closes (following SI signal)
132.0	132.0	BFD-5 feedwater block valve closes (following SI signal)
144.4	150.7	Containment sprays start (high-2 containment pressure of 24.62 psig)
248.2	254.0	Secondary side of steam generator tubes start to uncover in faulted steam generator
271.0	294.5	Peak containment pressure
1800.0	1800.0	Operator terminates AFW to faulted steam generator
1803.0	1803.0	Break releases stop

Table 6.6-5 MSLB Containment Response Analysis Initial Containment Conditions and Parameters	
RWST Water Temperature (°F)	110
Initial Containment Temperature (°F)	130
Initial Containment Pressure (psia) Maximum	 17.2
Initial Relative Humidity (%)	20
Net-Free Volume (ft^3)	2.61×10^6
Number of Containment Air Recirculation Fan Coolers	5
Number of Containment Spray Pumps	2

Table 6.6-6 Reactor Containment Fan Cooler Performance	
Containment Temperature (°F)	**Heat Removal Rate [Btu/sec] Per RCFC**
110	674
130	1737
150	2921
170	4162
190	5425
210	6684
230	8836
250	10986
271	13042

Table 6.6-7

Containment Spray Performance

Containment Pressure (psig)	Spray Flow Rate (gpm)
5.0	4819.4
10.0	4735.0
20.0	4561.8
30.0	4375.0
35.0	4278.6
40.0	4180.2
45.0	4080.2
50.0	3977.8

Table 6.6-8

Containment Heat Sinks

No.	Material	Thickness (ft)	Surface Area (ft^2)
1	Carbon Steel Concrete	0.03125 1.0	41302
2	Carbon Steel Concrete	0.04167 1.0	28613
3	Concrete	1.0	15000
4	Stainless Steel Concrete	0.03125 1.0	10000
5	Concrete	1.0	61000
6	Carbon Steel	0.0417	68792
7	Carbon Steel	0.03125	81704
8	Carbon Steel	0.02083	27948
9	Carbon Steel	0.015625	69800
10	Carbon Steel	0.01042	3000
11	Carbon Steel	0.0115	22000
12	Carbon Steel	0.0052	10000
Coatings	Paint	0.000625	Equal to carbon steel surface area

Table 6.6-9 Thermo-physical Properties of Containment Heat Sinks		
Material	**Thermal Conductivity (Btu/hr-ft - °F)**	**Volumetric Heat Capacity (Btu/ft^3 - °F)**
Paint	0.2083	36.86
Carbozinc	0.9	28.8
Carbon Steel	26.0	56.35
Stainless Steel	8.6	56.35
Concrete	0.8	28.8

Table 6.6-10 MSLB Peak Containment Pressure for IP3		
Break	**Single Failure**	**Peak Pressure @ Time (sec)**
Full DER, 102% Power	FCV	38.14 psig @ 271.0 sec
Full DER, 70% Power	FCV	39.2 psig @ 304.2 sec

Table 6.6-11 Nominal Plant Parameters for SPU[1] (MSLB M&E Releases Outside Containment)	
Nominal Conditions	
NSSS Power, MWt	3230.0[2]
Core Power, MWt	3216.0
Net Heat Addition, MWt	20[2]
Reactor Coolant Flow (total), gpm TDF	322,800
Pressurizer Pressure, psia	2250
Core Bypass, %	6.5
Reactor Coolant Vessel Average Temperature, °F	572.0[1]
Steam Generator	
Steam Temperature, °F	516.3
Steam Pressure, psia	787
Steam Flow, 10^6 lbm/hr (plant total)	14.01
Feedwater Temperature, °F	433.6
Zero-Load Temperature, °F	547

Notes:

1. Noted values correspond to plant conditions defined by 0% SGTP and the high end of the RCS T_{avg} window.
2. 14 MWt RCP heat addition was used for MSLB M&E analyses to determine NSSS power. A net heat addition of 20 MWt is conservatively assumed as additional energy that must be released through the faulted steam generator.

Table 6.6-12 Initial Condition Assumptions for SPU(1) (MSLB M&E Releases Outside Containment)		
Initial Conditions	**102% Power**	**70% Power**
RCS Average Temperature (°F)	579.5(1)	572(1)
RCS Flowrate (gpm TDF)	354,400	354,400
RCS Pressure (psia)	2250	2250
Pressurizer Water Volume (ft^3)	916.7	777.23
Feedwater Enthalpy (Btu/lbm)	412.2	377.2
Steam Generator Pressure (psia)(2)	787	787
Steam Generator Water Level (% NRS)	35	35

Notes:

1. Noted values correspond to plant conditions defined by 0% SGTP and the high end of the RCS T_{avg} window; temperatures include applicable calorimetric uncertainties.
2. The noted steam generator pressures were determined at the steady-state conditions defined by the RCS average temperatures, including applicable uncertainties.

Table 6.6-13 Main and AFWS Assumptions for SPU (MSLB M&E Releases Outside Containment)	
Main Feedwater System	
Flowrate – Both Power Levels (102% and 70%)	Nominal flow to all loops
Unisolable Volume from Steam Generator Nozzle to MFIV (all loops)	None assumed
AFW	
One motor-driven pump split evenly between faulted steam generator and one intact steam generator (Other MD AFW pump assumed to fail; no AFW to other two steam generators)	343 gpm
Manual Isolation Assumption	600 and 900 seconds [(1)]
Temperature (maximum value)	120°F
Piping Volume (faulted loop)	268.8 ft^3
Actuation Delay Time	60 seconds

Note:
1. See subsection 6.6.4.5 for discussion of use of 600 or 900 seconds.

Table 6.6-14 Protection System Actuation Signals and Safety System Setpoints for SPU (MSLB M&E Releases Outside Containment)
Reactor Trip Low-Low Steam Generator Water Level in any loop – 0% NRS Low-Pressurizer Pressure – 1748.7 psia Overtemperature ΔT $K_1 = 1.42$ $K_2 = 0.022$ $K_3 = 0.00070$ Dynamic Compensation lead – 25 seconds lag – 3 seconds Overpower ΔT $K_4 = 1.164$ $K_5 = 0.0$ $K_6 = 0.0015$ Dynamic Compensation rate lag – 10 seconds
Safety Injection Low-Pressurizer Pressure – 1648.7 psia Low-Steamline Pressure in any Loop – 435 psia
Steamline Isolation Low-Steamline Pressure in any Loop – 435 psia coincident with High Steam Flow
Feedwater Isolation Reactor Trip (conservative assumption)
AFW Initiation Low-Low Steam Generator Water Level in any Loop – 0% NRS SI

Table 6.6-15

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, Full Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	247	HSΔP	745	Manual	600.0	LSGL	305	600.0	701	984
0.2 / 0.2	LSGWL	128	LPP	513	Manual	600.0	LSGL	186	600.0	414[2]	761
0.3 / 0.3	LSGWL	88	LPP	307	Manual	600.0	LSGL	146	600.0	301[2]	652
0.4 / 0.4	LSGWL	67	LPP	222	Manual	600.0	LSGL	125	600.0	238[2]	620
0.5 / 0.5	OPΔT	31	LPP	151	Manual	600.0	LSGL	105	600.0	201[2]	613
0.6 / 0.6	OPΔT	25	LPP	123	Manual	600.0	LSGL	99	600.0	173[2]	609
0.7 / 0.7	OPΔT	22	LPP	104	Manual	600.0	LSGL	94	600.0	153[2]	607
0.8 / 0.8	OPΔT	20	LPP	91	Manual	600.0	LSGL	90	600.0	137[2]	605
0.9 / 0.9	OPΔT	19	LPP	80	Manual	600.0	LSGL	88	600.0	125[2]	605
1.0 / 1.0	OPΔT	18	LPP	72	Manual	600.0	LSGL	86	600.0	116[2]	604
1.2 / 1.2	OPΔT	16	LPP	60	Manual	600.0	LSGL	82	600.0	101[2]	603
1.4 / 1.4	OPΔT	15	LPP	52	Manual	600.0	LSGL	80	600.0	91[2]	603
2.0 / 1.4	OPΔT	13	HSF/L	33	HSF/L	40	LSGL	75	600.0	64	601
4.6 / 1.4	OPΔT	11	LPP	24	HSF/L	31	LSGL	71	600.0	50[2]	601

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT$_{avg}$ ≡ high-steam flow + low T$_{avg}$

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-16

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, 70% Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	203	HSΔP	853	Manual	600.0	LSGL	261	600.0	785	1070
0.2 / 0.2	LSGWL	105	LPP	460	Manual	600.0	LSGL	163	600.0	598	802
0.3 / 0.3	LSGWL	72	LPP	374	Manual	600.0	LSGL	130	600.0	385[2]	684
0.4 / 0.4	LSGWL	55	LPP	258	Manual	600.0	LSGL	113	600.0	295[2]	627
0.5 / 0.5	LSGWL	45	LPP	190	Manual	600.0	LSGL	103	600.0	244[2]	614
0.6 / 0.6	LSGWL	38	LPP	152	Manual	600.0	LSGL	96	600.0	208[2]	610
0.7 / 0.7	LSGWL	33	LPP	127	Manual	600.0	LSGL	91	600.0	183[2]	608
0.8 / 0.8	LSGWL	30	LPP	109	Manual	600.0	LSGL	88	600.0	163[2])	606
0.9 / 0.9	LSGWL	27	LPP	96	Manual	600.0	LSGL	85	600.0	149[2]	605
1.0 / 1.0	LSGWL	25	LPP	85	Manual	600.0	LSGL	83	600.0	137[2]	604
1.2 / 1.2	LSGWL	21	LPP	69	Manual	600.0	LSGL	79	600.0	119[2]	604
1.4 / 1.4	LSGWL	19	LPP	58	Manual	600.0	LSGL	77	600.0	107[2]	603
2.0 / 1.4	LSGWL	14	HSF/L	30	HSF/L	37	LSGL	72	600.0	64	601
4.6 / 1.4	LSGWL	8	HSF/L	19	HSF/L	26	LSGL	66	600.0	42	600

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. *The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.*
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-17

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, Full Power

Break Size (ft^2)	Reactor Trip		SI(1)		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	207	HSΔP	397	LSGL	265	600.0	335	726
0.2	LSGWL	106	HSΔP	135	LSGL	164	600.0	188	636
0.3	LSGWL	72	HSΔP	88	LSGL	130	600.0	137	618
0.4	LSGWL	54	HSΔP	66	LSGL	112	600.0	113	610
0.5	OPΔT	31	HSΔP	40	LSGL	94	600.0	94	606
0.6	OPΔT	24	HSΔP	32	LSGL	87	600.0	82	604
0.7	OPΔT	21	HSΔP	28	LSGL	84	600.0	74	604
0.8	OPΔT	20	HSΔP	25	LSGL	82	600.0	68	603
0.9	OPΔT	18	HSΔP	23	LSGL	80	600.0	63	603
1.0	OPΔT	17	HSΔP	22	LSGL	78	600.0	60	602
1.2	OPΔT	16	HSΔP	19	LSGL	74	600.0	53	601
1.4	LSGWL	13	HSΔP	15	LSGL	71	600.0	47	601

<u>Key</u>
LPP ≡ low-pressurizer pressure
HSΔP ≡ high-steamline differential pressure
HSF/LT$_{avg}$ ≡ high-steam flow + low T$_{avg}$
LSGL ≡ low-low steam generator water level
OPΔT ≡ overpower ΔT

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-18

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, 70% Power

Break Size (ft^2)	Reactor Trip		SI[1]		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	184	HSΔP	436	LSGL	242	600.0	371	758
0.2	LSGWL	94	HSΔP	130	LSGL	152	600.0	211	637
0.3	LSGWL	64	HSΔP	84	LSGL	122	600.0	155	618
0.4	LSGWL	49	HSΔP	63	LSGL	107	600.0	126	611
0.5	LSGWL	40	HSΔP	50	LSGL	98	600.0	109	607
0.6	LSGWL	30	HSΔP	37	LSGL	88	600.0	93	605
0.7	LSGWL	21	HSΔP	27	LSGL	79	600.0	80	604
0.8	LSGWL	17	HSΔP	21	LSGL	75	600.0	75	604
0.9	LSGWL	14	HSΔP	17	LSGL	72	600.0	71	603
1.0	LSGWL	12	HSΔP	14	LSGL	70	600.0	66	603
1.2	LSGWL	10	HSΔP	11	LSGL	68	600.0	59	601
1.4	LSGWL	8	HSΔP	8	LSGL	66	600.0	53	601

Key
LPP ≡ low-pressurizer pressure
HSΔP ≡ high-steamline differential pressure
HSF/LT$_{avg}$ ≡ high-steam flow + low T_{avg}
LSGL ≡ low-low steam generator water level
OPΔT ≡ overpower ΔT

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-19

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, Full Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	247	HSΔP	996	Manual	900.0	LSGL	305	900.0	788	1251
0.2 / 0.2	LSGWL	128	LPP	513	Manual	900.0	LSGL	186	900.0	414[2]	979
0.3 / 0.3	LSGWL	88	LPP	307	Manual	900.0	LSGL	146	900.0	301[2]	932
0.4 / 0.4	LSGWL	67	LPP	222	Manual	900.0	LSGL	125	900.0	238[2]	921
0.5 / 0.5	OPΔT	31	LPP	151	Manual	900.0	LSGL	105	900.0	201[2]	915
0.6 / 0.6	OPΔT	25	LPP	123	Manual	900.0	LSGL	99	900.0	173[2]	911
0.7 / 0.7	OPΔT	22	LPP	104	Manual	900.0	LSGL	94	900.0	153[2]	909
0.8 / 0.8	OPΔT	20	LPP	91	Manual	900.0	LSGL	90	900.0	137[2]	907
0.9 / 0.9	OPΔT	19	LPP	80	Manual	900.0	LSGL	88	900.0	125[2]	906
1.0 / 1.0	OPΔT	18	LPP	72	Manual	900.0	LSGL	86	900.0	116[2]	905
1.2 / 1.2	OPΔT	16	LPP	60	Manual	900.0	LSGL	82	900.0	101[2]	904
1.4 / 1.4	OPΔT	15	LPP	52	Manual	900.0	LSGL	80	900.0	91[2]	904
2.0 / 1.4	OPΔT	13	HSF/L	33	HSF/L	40	LSGL	75	900.0	64	903
4.6 / 1.4	OPΔT	11	LPP	24	HSF/L	31	LSGL	71	900.0	50[2]	903

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure; OPΔT ≡ overpower ΔT

HSF/LT$_{avg}$ ≡ high-steam flow + low T$_{avg}$

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-20

Summary of System Actuations for IP3 MSLB Outside Containment Header Breaks, 70% Power

Break Size (ft^2, before/ after steamline isolation)	Reactor Trip		SI[1]		MSIV Closure		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Fully Closed (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1 / 0.1	LSGWL	203	HSΔP	1144	Manual	900.0	LSGL	261	900.0	1058	1345
0.2 / 0.2	LSGWL	105	LPP	460	Manual	900.0	LSGL	163	900.0	598	1030
0.3 / 0.3	LSGWL	72	LPP	374	Manual	900.0	LSGL	130	900.0	385[2]	935
0.4 / 0.4	LSGWL	55	LPP	258	Manual	900.0	LSGL	113	900.0	295[2]	922
0.5 / 0.5	LSGWL	45	LPP	190	Manual	900.0	LSGL	103	900.0	244[2]	915
0.6 / 0.6	LSGWL	38	LPP	152	Manual	900.0	LSGL	96	900.0	208[2]	912
0.7 / 0.7	LSGWL	33	LPP	127	Manual	900.0	LSGL	91	900.0	183[2]	910
0.8 / 0.8	LSGWL	30	LPP	109	Manual	900.0	LSGL	88	900.0	163[2]	908
0.9 / 0.9	LSGWL	27	LPP	96	Manual	900.0	LSGL	85	900.0	149[2]	907
1.0 / 1.0	LSGWL	25	LPP	85	Manual	900.0	LSGL	83	900.0	137[2]	906
1.2 / 1.2	LSGWL	21	LPP	69	Manual	900.0	LSGL	79	900.0	119[2]	904
1.4 / 1.4	LSGWL	19	LPP	58	Manual	900.0	LSGL	77	900.0	107[2]	904
2.0 / 1.4	LSGWL	14	HSF/L	30	HSF/L	37	LSGL	72	900.0	64	902
4.6 / 1.4	LSGWL	8	HSF/L	19	HSF/L	26	LSGL	66	900.0	42	901

<u>Key</u>
LPP ≡ low-pressurizer pressure
LSGL ≡ low-low steam generator water level
HSΔP ≡ high-steamline differential pressure
OPΔT ≡ overpower ΔT
HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-21

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, Full Power

Break Size (ft^2)	Reactor Trip		SI(1)		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	207	HS∆P	397	LSGL	265	900.0	335	1002.
0.2	LSGWL	106	HS∆P	135	LSGL	164	900.0	188	941
0.3	LSGWL	72	HS∆P	88	LSGL	130	900.0	137	922
0.4	LSGWL	54	HS∆P	66	LSGL	112	900.0	113	913
0.5	OP∆T	31	HS∆P	40	LSGL	94	900.0	94	908
0.6	OP∆T	24	HS∆P	32	LSGL	87	900.0	82	906
0.7	OP∆T	21	HS∆P	28	LSGL	84	900.0	74	905
0.8	OP∆T	20	HS∆P	25	LSGL	82	900.0	68	904
0.9	OP∆T	18	HS∆P	23	LSGL	80	900.0	63	904
1.0	OP∆T	17	HS∆P	22	LSGL	78	900.0	60	903
1.2	OP∆T	16	HS∆P	19	LSGL	74	900.0	53	903
1.4	LSGWL	13	HS∆P	15	LSGL	71	900.0	47	902

<u>Key</u> LPP ≡ low-pressurizer pressure; LSGL ≡ low-low steam generator water level

HS∆P ≡ high-steamline differential pressure; OP∆T ≡ overpower ∆T

HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-22

Summary of System Actuations for IP3 MSLB Outside Containment Loop Breaks, 70% Power

Break Size (ft^2)	Reactor Trip		SI(1)		AFW			Time-Faulted Steam Generator Tubes Uncover (sec)	Time-Break Releases Stop (sec)
	Signal	Time Rod Motion Starts (sec)	Signal	Time of Signal (sec)	Signal	Time Flow Starts (sec)	Time Flow Stops (sec)		
0.1	LSGWL	184	HSΔP	436	LSGL	242	900.0	371	1005
0.2	LSGWL	94	HSΔP	130	LSGL	152	900.0	211	941
0.3	LSGWL	64	HSΔP	84	LSGL	122	900.0	155	922
0.4	LSGWL	49	HSΔP	63	LSGL	107	900.0	126	914
0.5	LSGWL	40	HSΔP	50	LSGL	98	900.0	109	909
0.6	LSGWL	30	HSΔP	37	LSGL	88	900.0	93	907
0.7	LSGWL	21	HSΔP	27	LSGL	79	900.0	80	906
0.8	LSGWL	17	HSΔP	21	LSGL	75	900.0	75	905
0.9	LSGWL	14	HSΔP	17	LSGL	72	900.0	71	904
1.0	LSGWL	12	HSΔP	14	LSGL	70	900.0	66	904
1.2	LSGWL	10	HSΔP	11	LSGL	68	900.0	59	903
1.4	LSGWL	8	HSΔP	8	LSGL	66	900.0	53	902

<u>Key</u> LPP ≡ low-pressurizer pressure LSGL ≡ low-low steam generator water level

HSΔP ≡ high-steamline differential pressure OPΔT ≡ overpower ΔT

HSF/LT_{avg} ≡ high-steam flow + low T_{avg}

1. The SI signal is generated, but the RCS pressure remains too high for delivery of SI flow.
2. The intact steam generator tubes also uncover and contribute superheated steam out the break.

Table 6.6-23

IP3 Outside Containment
Steam & Feed Penetration Area Initial Conditions

	Pressure (psia)	Temperature (°F)	Relative Humidity (%)
Winter			
Inside	14.7	110.0	100.0
Outside	14.7	84.0	70.0
Summer			
Inside	14.7	125.0	100.0
Outside	14.7	100.0	90.0

Table 6.6-24

Vented Steam Releases from Operable Steam Generators and AFW Flows for the 0-to-2 and 2-to-29 Hr Time Periods

Event	Vented Steam Release		AFW Injection	
	0-2 hours	2-29 hours	0-2 hours	2-29 hours
Locked Rotor	405,229 lbm	2,303,229 lbm	586,953 lbm	2,380,773 lbm
Steamline Break	401,945 lbm	2,273,538 lbm	538,238 lbm	2,331,696 lbm

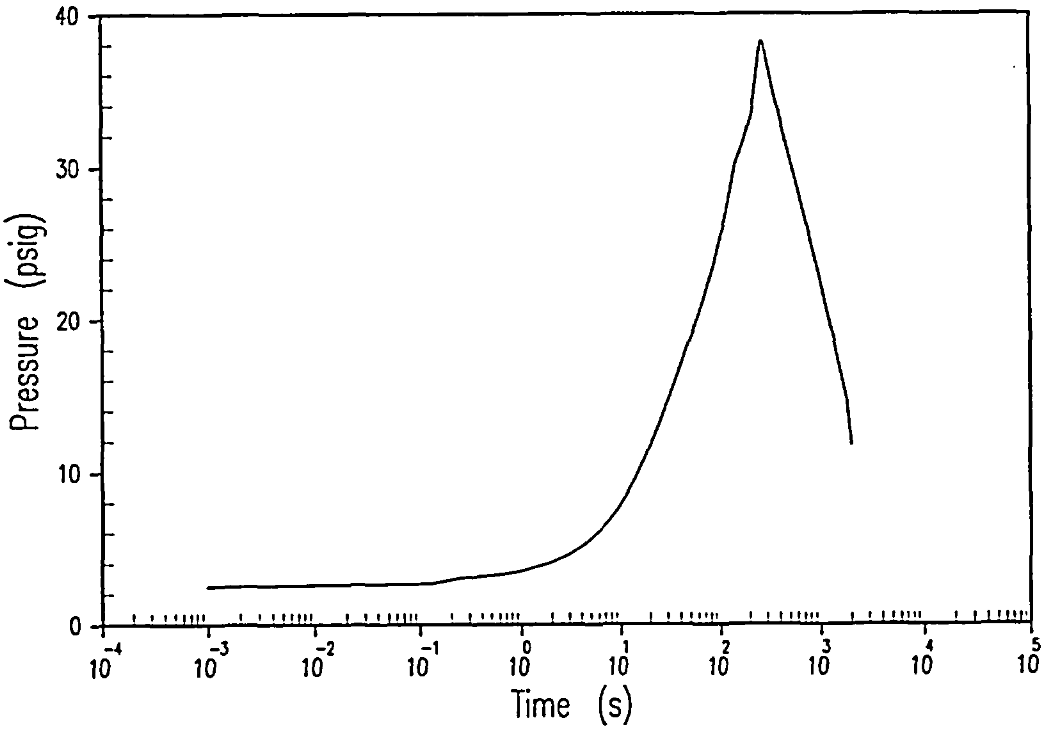


Figure 6.6-1

Containment Pressure Curve for 102% Power MSLB for IP3

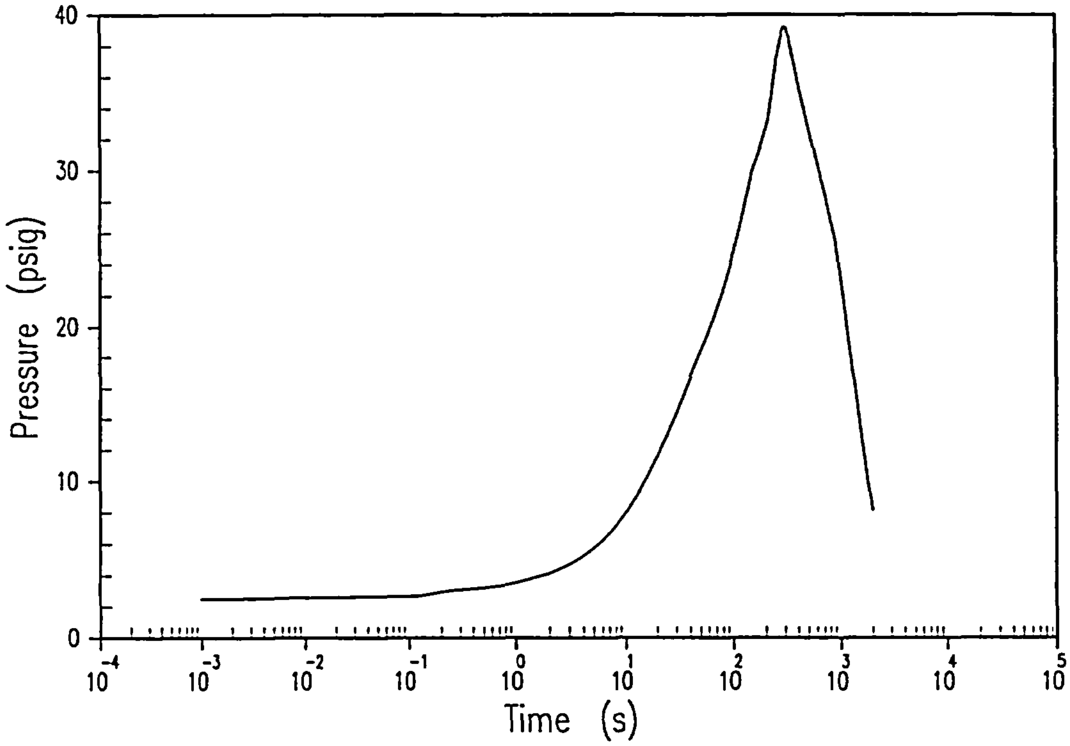


Figure 6.6-2

Containment Pressure Curve for 70% Power MSLB for IP3

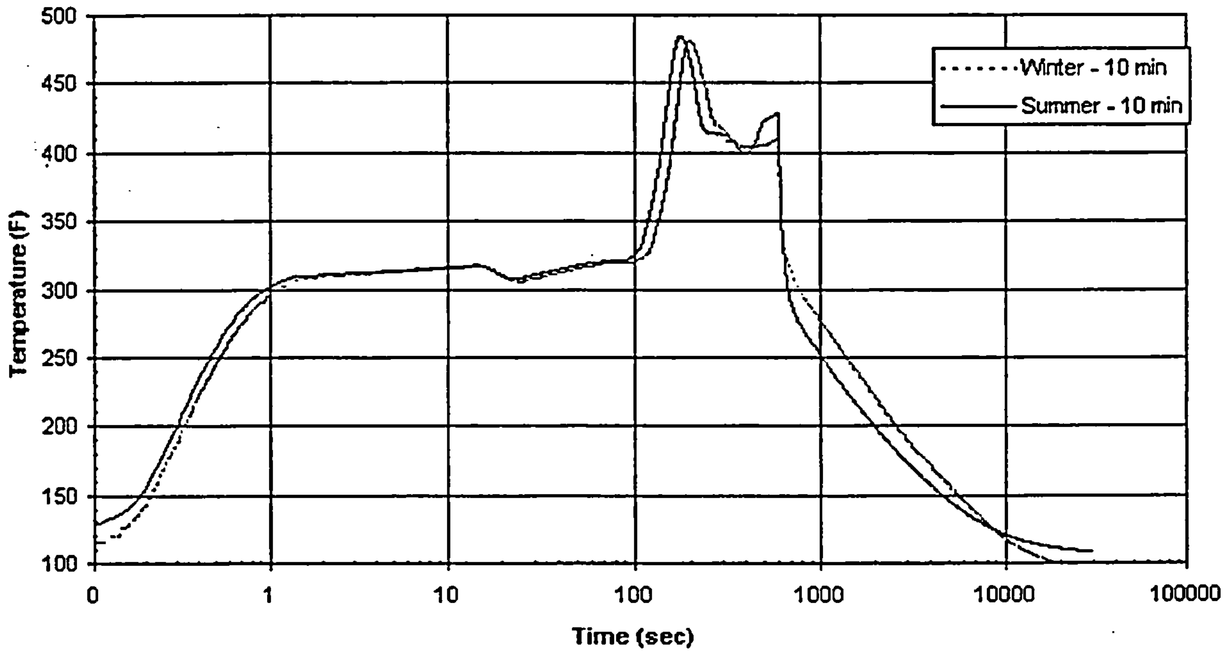


Figure 6.6-3

IP3 MSLB Outside Containment Limiting Break Temperature Profiles

(10-minute operator action time)

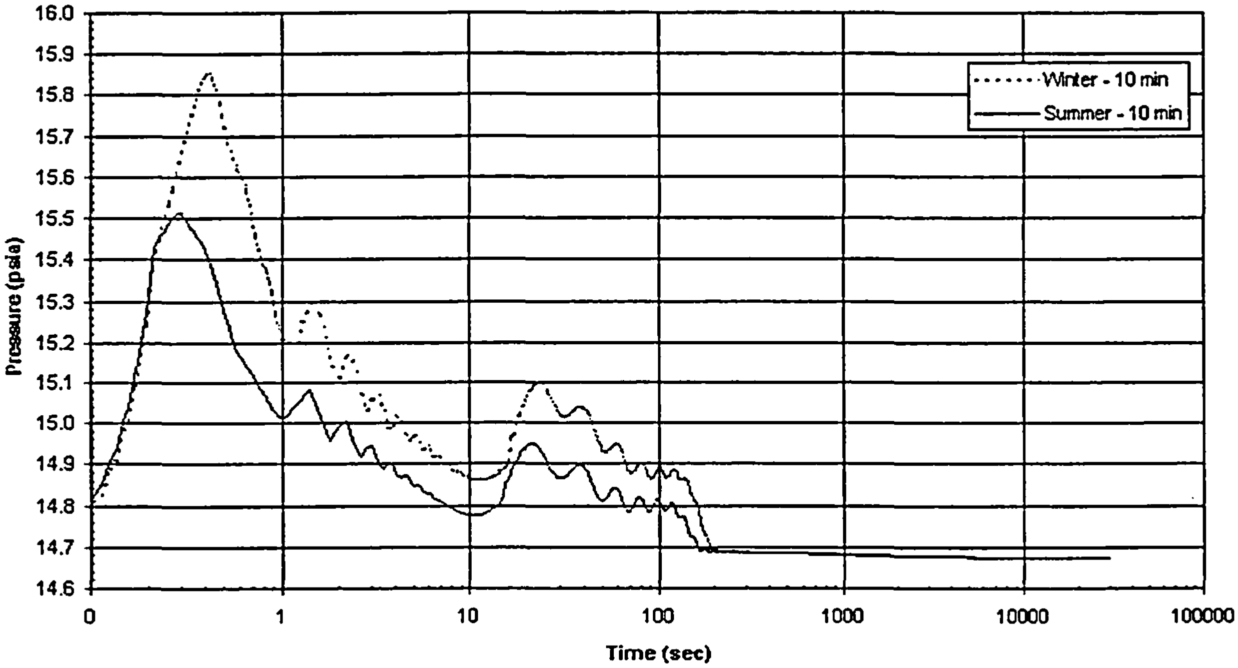


Figure 6.6-4

IP3 MSLB Outside Containment Limiting Break Pressure Profiles

(10-minute operator action time)

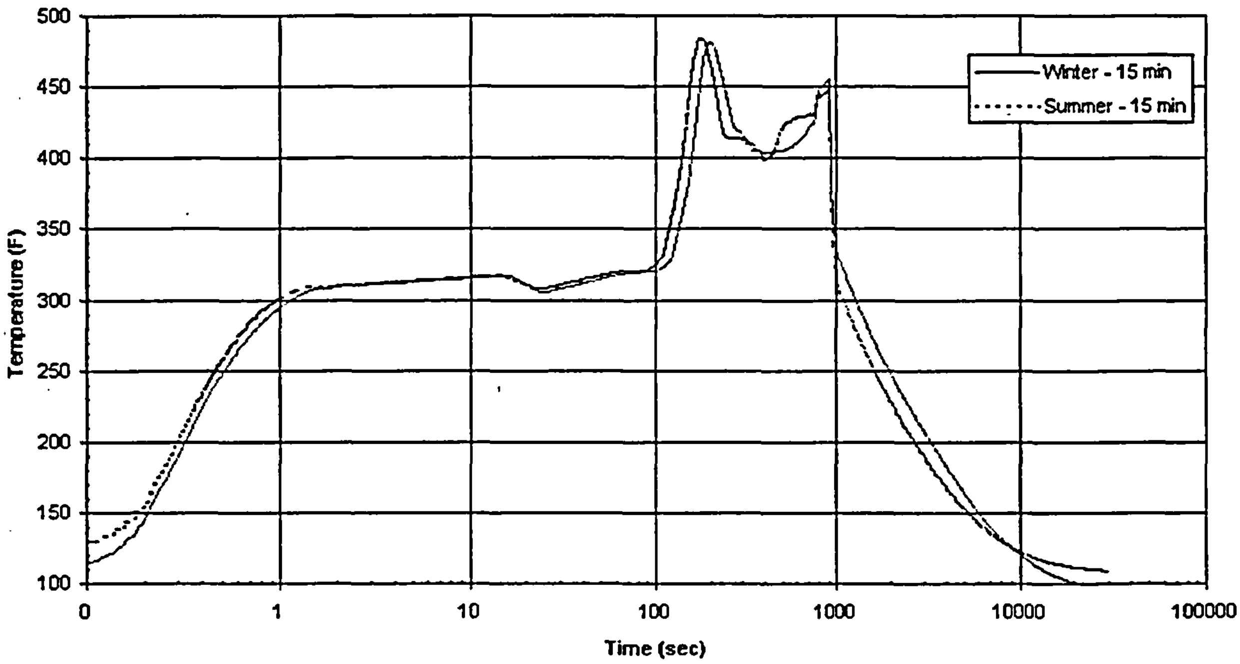


Figure 6.6-5

IP3 MSLB Outside Containment Limiting Break Temperature Profiles

(15-minute operator action time)

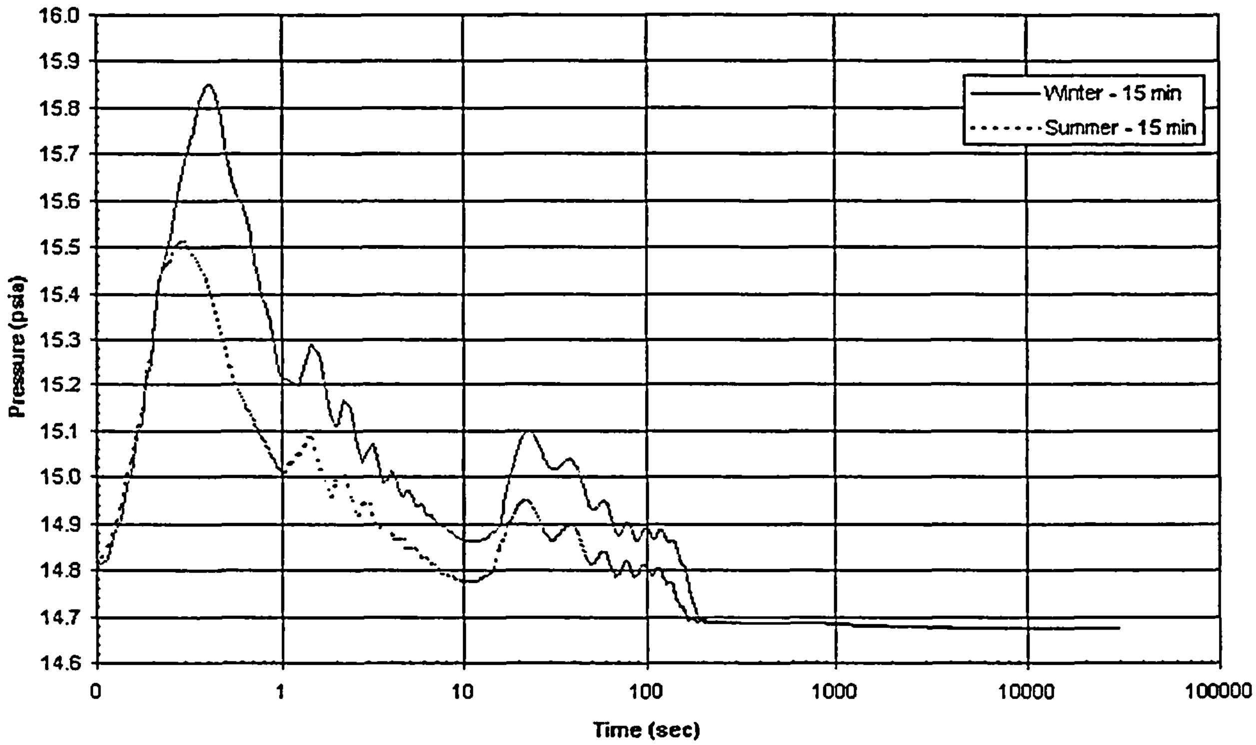


Figure 6.6-6

IP3 MSLB Outside Containment Limiting Break Pressure Profiles

(15 minute operator action time)

6.7 Loss-of-Coolant Accident Hydraulic Forces

6.7.1 Introduction

The loss-of-coolant accident (LOCA) hydraulic forces analysis generates the hydraulic forcing functions that would act on Reactor Coolant System (RCS) components as a result of a postulated LOCA. The LOCA hydraulic forces were calculated for conditions consistent with minimum thermal design flow and maximum RCS power. The Indian Point Unit 3 (IP3) stretch power uprate (SPU) used the advanced beam model version of MULTIFLEX (3.0) (Reference 1) in accordance with methodology approved by the NRC in WCAP-15029-P-A and WCAP-15030-NP-A (Reference 2).

6.7.2 Input Parameters and Assumptions

To conservatively calculate LOCA hydraulic forces for IP3, the following operating conditions were considered in establishing the limiting temperatures and pressures:

- Initial RCS conditions associated with a minimum thermal design flow of 88,600 gpm per loop
- Uprated core power of 3216 MWt (Nuclear Steam Supply System [NSSS] power of 3230 MWt)
- A nominal RCS hot full power (HFP) T_{avg} range of 549.0° to 572.0°F. This provides an RCS T_{cold} range of 517.3° to 541.0°F (see Table 2.1-2 of Section 2).
- An RCS temperature uncertainty of ±7.0°F. (The minimum analyzed T_{cold} was 510.3°F.)
- A feedwater temperature range of 390.0° to 433.6°F
- A nominal RCS pressure of 2250 psia
- A pressurizer pressure uncertainty of ±75 psi

General Design Criterion 4 (GDC-4) (Reference 3) allows main coolant piping breaks to be "...excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping." This exemption is generally referred to as leak-before-break (LBB). The technical justification for application of LBB to IP3 is documented in WCAP-8228 Vol. 1, Rev. 1 (Reference 4).

LBB licensing allows RCS components to be evaluated for LOCA integrity considering the next most limiting auxiliary line breaks, that for IP3, are the accumulator line, the pressurizer surge line, and the residual heat removal line.

6.7.3 Description of Evaluation

LOCA forces were generated with a focus on the component of interest; loop, vessel, steam generator, or rod control cluster assembly (RCCA) guide tubes using the advanced beam model version of MULTIFLEX (3.0) (Reference 1), assuming a conservative break-opening time (BOT) of 1 millisecond (msec).

Generally, this improved modeling results in lower, more realistic, but still conservative hydraulic forces on the core barrel.

The MULTIFLEX computer code calculated the thermal-hydraulic transient within the RCS and considers subcooled, transition, and early two-phase (saturated) blowdown regimes. The code used the method of characteristics to solve the conservation laws, assuming one-dimensional (1-D) flow and a homogeneous liquid-vapor mixture. The RCS was divided into subregions in which each subregion was regarded as an equivalent pipe. A complex network of these equivalent pipes was used to represent the entire primary RCS.

For the reactor pressure vessel (RPV) and specific vessel internal components, the MULTIFLEX code generated the LOCA thermal-hydraulic transient that was input to the LATFORC and FORCE2 post-processing codes (Reference 5). These codes, in turn, were used to calculate the actual forces on the various components.

These forcing functions for horizontal and vertical LOCA hydraulic forces, combined with seismic, thermal, and system-shaking loads, were used by the cognizant structural groups to determine the resultant mechanical loads on the RPV and vessel internals.

The loop forces analysis use the THRUST post-processing code to generate the X, Y, and Z directional component forces during a LOCA blowdown from the RCS pressure, density, and mass flux calculated by the MULTIFLEX code. The THRUST code is described and documented in WCAP-8252 (Reference 6).

The hydraulic transient time-history data were extracted directly from the MULTIFLEX output for steam generator and some reactor vessel internal components, such as baffle bolts or RCCA guide tubes.

6.7.4 Acceptance Criteria

LOCA hydraulic forces were provided as input to structural qualification analyses, and as such, had no independent regulatory acceptance criteria.

6.7.5 Results

For the IP3 SPU, all relevant LOCA hydraulic forces analyses were performed directly at the uprated power operating conditions using models specific to the IP3 NSSS design. These analyses included reactor vessel internals and fuel, loop piping, steam generator, and RCCA guide tube forces. The results of these analyses were then used as input to the structural analyses for component qualification.

6.7.6 Conclusions

LOCA hydraulic forces were generated for IP3 for the SPU conditions specified in subsection 6.7.2 of this document. These LOCA hydraulic forcing functions are used in the structural analyses in Section 5 of this report.

6.7.7 References

1. WCAP-9735, Rev. 2 (Proprietary) and WCAP-9736, Rev. 1, (Nonproprietary), *MULTIFLEX 3.0 A FORTRAN IV Computer Program for Analyzing Thermal-Hydraulic-Structural System Dynamics Advanced Beam Model*, K. Takeuchi, et al., February 1998.

2. WCAP-15029-P-A (Proprietary) and WCAP-15030-NP-A (Nonproprietary), *Westinghouse Methodology for Evaluating the Acceptability of Baffle-Former-Barrel Bolting Distributions Under Faulted Load Conditions*, R. E. Schwirian, et al., January 1999.

3. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

4. WCAP-8228, Volume 1, (Proprietary), *Structural Evaluation of Reactor Coolant Loop/Support System for Indian Point Nuclear Generating Station, Unit No. 3*, D. C. Bhowmick, et al., Rev. 1, April 1997.

5. WCAP-8708-P-A (Proprietary) and WCAP-8709-A (Nonproprietary), *MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics*, K. Takeuchi, et al., September 1977.

6. WCAP-8252 (Nonproprietary), Documentation of Selected Westinghouse Structural Analysis Computer Codes, K. M. Vashi, Rev. 1, May 1977.

6.8 Anticipated Transients without Scram

6.8.1 Introduction

For Westinghouse-designed pressurized water reactors (PWRs), the licensing requirements related to anticipated transients without scram (ATWS) are specified in the Final ATWS Rule, 10CFR50.62(c) (Reference 1). The requirement set forth in 10CFR50.62(c) is that all Westinghouse-designed PWRs must install AMSAC (ATWS Mitigation System Actuation Circuitry) and, in compliance with this, AMSAC has been installed and implemented at Indian Point Unit 3 (IP3).

As documented in SECY-83-293 (Reference 2), the analytical bases for the Final ATWS Rule are the generic ATWS analyses for Westinghouse PWRs generated by Westinghouse in 1979. These generic ATWS analyses were formally transmitted to the Nuclear Regulatory Commission (NRC) via letter NS-TMA-2182 (Reference 3), and were performed based on the guidelines provided in NUREG-0460 (Reference 4). The generic ATWS analysis assumed nominal conditions consistent with the requirements outlined by the NRC. In consideration of the low probability of an ATWS, the NRC permitted nominal initial conditions, nominal system parameters, and the availability of all system functions except reactor trip to be assumed.

The generic ATWS analyses that are documented in NS-TMA-2182 (Reference 3) were performed with the LOFTRAN computer code and addressed the various American Nuclear Society (ANS) Condition II events (that is, anticipated transients), considering various Westinghouse PWR configurations applicable at that time. These analyses addressed two-, three-, and four-loop PWRs with various steam generator models. For IP3, the generic ATWS analyses applicable at that time were those for a four-loop PWR with Model 44 steam generators and a core power of 3025 MWt. These conditions are summarized in Table 3-1-d of NS-TMA-2182 (Reference 3). For this plant configuration, the peak Reactor Coolant System (RCS) pressure reported in NS-TMA-2182 for the limiting loss-of-load ATWS event is 2979 psia.

The generic ATWS analyses documented in NS-TMA-2182 (Reference 3) also support the analytical basis for the NRC-approved generic AMSAC designs generated for the Westinghouse Owners Group (WOG), as documented in WCAP-10858-P-A, Revision 1 (Reference 5). For the purpose of these AMSAC designs, the generic ATWS analyses for the four-loop PWR configuration with Model 51 steam generators were used to conservatively represent all of the various Westinghouse PWR configurations contained in NS-TMA-2182. For IP3, WCAP-10858P-A AMSAC Logic 2, AMSAC actuation on low main feedwater flow was used.

As prescribed by NUREG-0460 (Reference 4), the 1979 generic ATWS analyses for Westinghouse PWRs documented in NS-TMA-2182 (Reference 3) assumed a full-power moderator temperature coefficient (MTC) of -8 pcm/°F. A sensitivity analysis including the use of an MTC of -7 pcm/°F was also provided as prescribed by NUREG-0460. In 1979, the MTC values of -8 pcm/°F and -7 pcm/°F represented MTCs that Westinghouse PWRs would be more negative than for 95 and 99 percent of the cycle, respectively. The base case of 95 percent represents a 95-percent confidence limit on favorable MTC for the fuel cycle. For IP3, the *Technical Specification* requirement on MTC is limited to < 0 pcm/°F at all power levels. The current MTC *Technical Specification* for IP3 remains the same as that which was applicable for most Westinghouse PWRs in 1979. Therefore, the reactivity feedback for IP3 remains sufficiently negative to be comparable to the generic Westinghouse ATWS analyses presented in NS-TMA-2182.

Relative to the other conditions important to the ATWS analyses, the pressurizer power-operated relief valve (PORV) relief capacity, safety valve relief capacity, and auxiliary feedwater (AFW) capacity are unaffected by the stretch power uprate (SPU). The design capacities of both of the IP3 pressurizer PORVs (179,000 lbm/hr) are consistent with the relief capacities assumed in the 1979 generic ATWS analysis for this plant configuration. The design capacity of each of the three IP3 pressurizer safety relief valves is 420,000 lbm/hr. This capacity is greater than the pressurizer safety valve relief capacity of 408,000 lbm/hr assumed in the 1979 generic ATWS analysis for this plant configuration. As such, this would result in an overall peak pressure benefit when compared to peak RCS pressure calculated for the generic limiting ATWS events.

The design capacities of the IP3 AFW pumps are as follows.

- Motor-driven AFW pump - 400 gpm
- Turbine-driven AFW pump - 800 gpm

The IP3 Auxiliary Feedwater System (AFWS) has two motor-driven AFW pumps (MDAFWPs) (each pump aligned to two steam generators) and a turbine-driven AFW pump (TDAFWP) that requires operator action to initiate flow to all four steam generators. Since operator action is required at IP3 to deliver TDAFWP flow to the steam generators, IP3 can only credit AFW flow from the two MDAFWPs. Based on the safety analysis AFW flows of 343 gpm from each MDAFWP, the total AFW flow at IP3 would be 686 gpm. This lower AFWS flow would result in an overall peak pressure penalty when compared to the total AFWS capacity of 1760 gpm, assumed in the 1979 generic ATWS analyses for the Westinghouse four-loop plant configuration with Model 44 steam generators (as documented in Table 3-1-d of NS-TMA-2182 [Reference 3]).

For the IP3 SPU, the two most limiting RCS overpressure transients reported in NS-TMA-2182 (Reference 3), the loss-of-normal feedwater (LONF) and loss-of-load (LOL) transients, were analyzed at the SPU conditions to ensure that the basis for the final ATWS rule continues to be met.

The primary inputs to the LONF and LOL ATWS analyses performed in support of the IP3 SPU are the four-loop reference LONF and LOL ATWS models with Model 44 steam generators supporting NS-TMA-2182 (Reference 3). The nominal and initial conditions were updated to reflect an NSSS power of 3230 MWt corresponding to the SPU, as well as a total AFW flow of 686 gpm.

6.8.2 Acceptance Criteria and Conclusions

To remain consistent with the basis of the Final ATWS Rule (Reference 1) and the supporting analysis reported in NS-TMA-2182 (Reference 3), the peak RCS pressure for the ATWS events for IP3 at an NSSS power level of 3230 MWt corresponding to the SPU shall not exceed the ASME Boiler and Pressure Vessel Level C service limit stress criterion of 3200 psig (3215 psia).

The results of the LONF and LOL ATWS analyses performed at an SPU NSSS power level of 3230 MWt with Model 44 steam generators are provided in Table 6.8-1. The results show that assuming the IP3 plant-specific AFW flow of 686 gpm results in higher peak RCS pressures than what were calculated based on the AFW flow rate of 1760 gpm from NS-TMA-2182 (Reference 3). However, the results do not exceed the ASME Boiler and Pressure Vessel Code Level C service limit stress criterion of 3200 psig (3215 psia). In fact, the peak RCS pressures are significantly less than the limit value of 3215 psia.

For the LONF and LOL cases analyzed at the SPU power level of 3230 MWt, the calculated peak RCS pressures of 2814 psia and 2862 psia, respectively, are less limiting than the corresponding peak pressures of 2857 psia and 2979 psia obtained for the LONF and LOL cases, respectively, in the 1979 ATWS analyses for four-loop Model 44 steam generators (Reference 3). The lower RCS pressures are attributed to the lower initial steam generator steam temperature associated with the IP3 SPU. For the SPU, the initial steam temperature is ~17°F lower than what was assumed in the 1979 ATWS analysis (Reference 3).

Furthermore, these analyses results do not credit the overall peak pressure benefit associated with the higher pressurizer safety valve relief capacity for IP3.

In conclusion, operation of IP3 at an SPU NSSS power of 3230 MWt remains in compliance with the Final ATWS Rule, 10CFR50.62(c) (Reference 1).

6.8.3 References

1. 10CFR50.62, *Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants,* July 29, 1996.

2. SECY-83-293, *Amendments to 10CFR50 Related to Anticipated Transients Without Scram (ATWS) Events,* W. J. Dircks, July 19, 1983.

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

4. NUREG-0460, *Anticipated Transients Without Scram for Light Water Reactors,* December 1978.

5. WCAP-10858-P-A, *AMSAC Generic Design Package, Westinghouse Topical Report,* Rev. 1, M. R. Adler, July 1987.

Table 6.8-1 LONF and LOL ATWS Analyses Results		
	Peak RCS Pressure (psia)	
AFW Flow (gpm)	LONF	LOL
1760 gpm (Ref. 3 flow)	2783	2836
686 gpm	2814	2862

6.9 Natural Circulation Cooldown Capability

6.9.1 Introduction

Certain initiating events, such as a loss-of-offsite power (LOOP) can cause a reactor trip with loss of forced circulation. As the reactor coolant pumps (RCPs) coast down, a coolant density difference is established between the Reactor Coolant System (RCS) hot-leg and cold-leg sides that causes flow to circulate, allowing residual heat to be transferred to and removed by the steam generators. This process of natural circulation cooling has been observed in Westinghouse-designed pressurized water reactors (PWRs) in startup tests as well as actual events. In addition, Diablo Canyon Unit 1, a four-loop PWR similar to Indian Point Unit 3 (IP3), has performed a test to demonstrate capability to cooldown the RCS to residual heat removal (RHR) initiation conditions (below 350°F and ~400 psig) via this natural circulation cooling process. The recovery guidance used for this test as well as the IP3 plant-specific Emergency Operating Procedures (EOPs) has been based on the Westinghouse Owners Group Emergency Response Guidelines (ERGs), specifically ES-0.2, *Natural Circulation Cooldown.*

To demonstrate that the stretch power uprate (SPU) does not adversely affect the natural circulation cooling capability of the IP3 plant, a short-term (20-minute) analysis simulation was performed. A comparison to the Indian Point Unit 2 (IP2) scenario was then made to evaluate the longer term portion. In addition to providing or supporting the technical basis for the EOPs, this simulation plus comparison has helped demonstrate the following:

- The maximum temperature differential ($T_{hot} - T_{cold}$) and maximum hot-leg temperatures are bounded by full power operation.

- The capacity of the steam generator atmospheric relief valves (ARVs) does not limit the capability to cooldown to RHR cut-in conditions (350°F, 400 psig).

6.9.2 Analysis Methods and Inputs

The IP3 EOPs, which are based on the ERGs, were reviewed in performing the long-term comparison and also the short-term simulation using the TREAT computer code. This analysis and comparison were performed in a conservative manner using realistic time delays and equipment limitations. For example, the simulation assumed a "locked rotor" RCP hydraulic resistance following RCP coastdown. The longer term portion included a 4-hour delay at hot standby to allow boration to cold shutdown, a natural circulation cooldown rate of 20°F/hr (versus a maximum 25°F/hr allowed for a T_{hot} upper-head plant), and an 8-hour delay to allow the upper head to cool or "soak" before depressurizing to the RHR cut-in pressure. As per the ERG generic analysis, this upper-head soak delay is included to allow the upper-head region

sufficient time to cool due to the assumed loss of control rod drive mechanism (CRDM) fans. If the CRDM fans were operating, the upper-head region would cool down at a rate comparable to the rest of the RCS and this 8-hour delay to preclude steam void formation in the upper head would not be necessary.

Other important assumptions were:

- Decay heat rate is approximately the same as the ANSI/ANS-5.1-1979 standard (Reference 1), including +2 sigma uncertainty, with full-power operation at 3288.4 MWt core power for an extended period of time (3.2 years average fuel exposure). (This power level bounds 102 percent of 3216 MWt.)

- There is a total capacity for all 4 steam generator ARVs = 2,503,612 lbm/hr at the valve inlet pressure of 1020 psig = 1035 psia.

6.9.3 Simulation Results

For the short-term maximum temperature response, the decay heat is approximately 3 percent of full power by the time the RCPs coast down and the core/hot-leg side heats up to quasi steady-state conditions. This condition occurs approximately 5 minutes after the RCPs and the reactor trip. Results calculated for this situation are the following:

- Hot-leg/core exit temperature = 593°F
- Hot- to cold-leg Delta-T = 40°F
- Cold-leg temperature = 553°F
- Core flow rate ≅ 6.15 x 10^6 lbm/hr (approximately 4.5 percent of nominal)

For this maximum temperature condition, the cold-leg temperatures are assumed to be controlled by the lowest main steam safety valve (MSSV) pressure set-point (1080 psia, T_{sat} = 554°F). Soon after reactor trip, the operator would control this temperature to no-load (547°F), as instructed in the EOPs, by operation of the steam generator ARVs. Thus, the above temperatures for T_{hot} and T_{cold} would be reduced accordingly by about 5 to 10°F. The above hot-leg/vessel-outlet temperature is approximately 10°F less than the maximum Performance Capability Working Group (PCWG) temperature of (603°F). Since the RCS is initially controlled to ~2100 to 2250 psia (T_{SAT} = 643 to 653°F), it would typically be subcooled by more than 50°F at the core exit/hot-legs at this maximum temperature condition.

For the comparison portion, it is noted that the IP2 and IP3 EOP actions taken would be the same, apart from differences in certain EOP setpoint values. These differences would have minor impact on the cooldown scenario. Both EOPs limit the RCS cooldown rate to 25°F/hr and assume an 8-hour upper head "soak" delay if CRDM fans are not in service. IP3 performs this

upper head “soak” delay in two pieces because of pressure-temperature limitations, but the overall impact on the scenario longer term response would not be significant.

6.9.4 Conclusion

By performing the short-term analysis for IP3 and making a comparison of IP3 parameters to IP2, it is concluded that the SPU will not adversely impact the natural circulation cooldown capability of the plant.

6.9.5 References

1. ANSI/ANS-5.1-1979, American *National Standard for Decay Heat Power in Light Water Reactors*, August 1979.

2. WCAP-16157, *Indian Point Nuclear Generating Unit No. 2 - Stretch Power Uprate NSSS and BOP Licensing Report*, January 2004. (Section 6.9)

6.10 Reactor Trip System/Engineered Safety Feature Actuation System Setpoints

6.10.1 Introduction

The Reactor Trip System (RTS)/Engineered Safety Feature Actuation System (ESFAS) nominal trip setpoints (NTSs) and *Technical Specifications* (Reference 1) allowable values (AVs) have been reviewed for operation at the stretch power uprate (SPU) conditions. As a result of this review, several NTS and AV changes have been identified.

6.10.2 Description of Analyses and Evaluations

The setpoint analysis uses the square-root-sum-of-the-squares (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. Those uncertainties that are not independent arithmetically summed to produce groups that are independent of each other, which can then be statistically combined. The method used for determining NTSs and AVs for the Indian Point Unit 3 (IP3) stretch power uprate (SPU) is defined in IP3 Engineering Standard IES-3B, Revision 0 (Reference 2) and is the same as used for the recently NRC-approved 1.4-percent measurement uncertainty recapture (MUR). However, where *Technical Specifications* (Reference 1) AVs were affected, these were recalculated in accordance with both the above-referenced engineering standard, which utilizes ISA 67.04 Method 3, and the methodology described in for the Indian Point Unit 2 (PU Licensing Amendment Request (LAR) package, which imposes ISA 67.04 Method 2 requirements for determining AVs. As a result, the changed AVs shown in the Reactor Protection System (RPS)/ESFAS *Technical Specification* markups (included as Attachment II of the IP3 LAR package) conservatively bound the AVs determined via both of the identified methods.

In accordance with requirements issued by the NRC, for implementation of surveillance frequency extensions for RPS/ESFAS instrument components, IP3 instituted a component drift Performance Monitoring Program. This program, which includes the performance tracking of over 1000 instrument components, benchmarks expected drift characteristics of each device in the program.

Recorded As-Found/As-Left data sets, collected during the field calibrations/surveillances, are screened for resultant drift magnitude and compared to the benchmark values, which are the basis for drift allowances in the RPS/ESFAS uncertainty calculations. Components, whose observed drift magnitude exceeds the benchmark values, are posted on a "Degraded Instruments Watch List" (assuming they can be successfully be brought into required As-Left tolerance). Subsequent surveillance results are specifically reviewed for these instruments and

determinations are made relative to cause and appropriate corrective actions, which can be the following:

- Increase surveillance frequency (to collect more data)
- Repair/Replace the device (where observed degradation is confirmed)
- Revise surveillance procedural steps (where inappropriate steps are inducing observed degradation)
- Review/Revise the uncertainty calculation drift allowances (where benchmark values are determined to be inappropriate)

The IP3 RTS/ESFAS uncertainty calculations were evaluated based on operation at the SPU operating conditions, along with the plant-specific instrumentation and plant calibration procedures, and any revisions to the safety analysis limits (SALs) values that were required to support operation at the SPU conditions. Several setpoint calculations were affected due to revised SALs or changes in instrumentation hardware and scaling/calibration.

6.10.3 Acceptance Criteria and Results

The setpoint methodology defines the distance between the limiting *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 3) SAL and the NTS as the channel uncertainty (CU), plus any setpoint margin that may have been applied. Margin is defined as the difference between the calculated limiting NTS (SAL plus or minus CU) and the implemented NTS. The acceptance criterion for the RTS/ESFAS setpoints is that margin is greater than or equal to zero.

Setpoint calculations were performed for the affected RTS/ESFAS parameters. Table 6.10-1 summarizes the most limiting SALs, NTS, and *Technical Specifications* AVs for the parameters that were affected by the IP3 SPU. Incorporation of these AVs and NTS changes will support operation at SPU conditions in a manner consistent with the UFSAR (Reference 3) assumptions. Functions not listed in Table 6.10-1 were not affected by the IP3 SPU. The steam generator water level uncertainty calculations included the resolution of the generic uncertainty issues (References 4 through 7), which are unrelated to the SPU.

6.10.4 Conclusions

With the setpoint and allowable value changes as shown on Table 6.10-1, all of the RTS/ESFAS functions have acceptable margins and, therefore, are acceptable for operation at the uprated core power of 3216 MWt.

6.10.5 References

1. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3 Docket No. 50-286 Technical Specifications and Bases.*

2. IP3 Engineering Standard IES-3B, *Instrument Loop Accuracy and Setpoint Calculation Methodology*, Rev. 0

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

4. NSAL-02-03, *Steam Generator Mid-deck Plate Pressure Loss Issue*, Rev. 1, April 2002.

5. NSAL-02-04, *Maximum Reliable Indicated Steam Generator Water Level*, Rev. 0, February 2002.

6. NSAL-02-05, *Steam Generator Water Level Control System Uncertainty Issue*, Rev. 1, April 2002.

7. NSAL-03-09, *Steam Generator Water Level Uncertainties*, Rev. 0, September 2003.

Table 6.10-1 IP3 SPU Summary of RTS/ESFAS Setpoint Calculations			
Protection Function	**NTS**	**SAL Value**	**Tech. Spec. AV**
Nuclear Instrumentation System (NIS) Power Range Reactor Trip High Setpoint	≤108% rated thermal power (RTP)	118% RTP	≤111% RTP
Overtemperature ΔT Reactor Trip			
K_1 Max		1.42	
K_1 Nominal	≤1.22		≤1.26
K_2	0.022 /°F	0.022 /°F	
K_3	0.00070 /psi	0.00070 /psi	
Overpower ΔT Reactor Trip			
K_4 Max		1.164	
K_4 Nominal	≤1.074		≤1.10
K_5 (decreasing T_{avg})	0	0	
K_5 (increasing T_{avg})	0.0175/°F	0.0175/°F	
K_6 ($T \geq T''$)	0.0015/°F	0.0015/°F	
K_6 ($T < T''$)	0	0	
Pressurizer Pressure Low (Reactor Trip)	1930 psig	1850 psia	1900 psig
Pressurizer Pressure Low (SI Initiation)	1780 psig	1648.7 psia	1710 psig
Steam Flow in Two Steamlines – High (SI/SL actuation)	≤43% full flow between 0 and 20% load, increasing linearly to ≤110% full flow at 100% load	78% full flow between 0 and 20% load, increasing linearly to 144% full flow at 100% load (1)	≤54% full flow between 0 and 20% load, increasing linearly to ≤120% full flow at 100% load
T_{avg} – Low Coincidence with High Steam Flow (SI/SL actuation)	≥542°F	535°F (1)	≥540.5°F

Note:

1. Although the SAL is beyond the instrument range, the uncertainty calculation confirmed that all uncertainties subject to saturation can be accommodated between the NTS and the instrument span limit.

6.11 Radiological Assessments

6.11.1 Introduction

This section addresses the radiological effects of the stretch power uprate (SPU) at Indian Point Unit 3 (IP3). The current licensing basis core power level is 3067.4 MWt. The SPU core power level is 3216 MWt (that is, an increase of approximately 4.85 percent with respect to the current power level).

The SPU was evaluated for its effect on the following radiological areas:

- Normal operation dose rates and shielding
- Normal operation annual radwaste effluent releases
- Radiological environmental doses for equipment qualification (EQ)
- Post-loss-of-coolant-accident (LOCA) access to vital areas
- Post-accident offsite and control room doses

In accordance with regulatory guidance, radiological evaluations for accident-related issues are assessed at a core power level of 3216 MWt plus 2 percent to address power measurement uncertainties (for a total of 3280.3 MWt). Installation of improved feedwater measurement instrumentation used for calorimetric power calculation allows for instrument error to be reduced from the traditional 2 percent as recommended in Regulatory Guide (RG) 1.49 (Reference 1). The reduction of the uncertainty allowance for calorimetric thermal power measurement to 0.6 percent was approved by the NRC in its *Safety Evaluation Report* (SER) for License Amendment No. 213 for IP3 (Reference 2). However, IP3 has decided to return to the use of the traditional 2 percent uncertainty.

Except as noted, radiological evaluations for normal-operation-related issues were assessed for the SPU at a core power level of 3216 MWt. In accordance with regulatory guidance, the radwaste effluent assessment assumed a core power level of 3280.3 MWt, but used flow rates and coolant masses at the Nuclear Steam Supply System (NSSS) power level of 3230 MWt.

The SPU evaluations discussed in this section associated with normal operation dose rate/shielding adequacy, normal operation radwaste effluents, environmental levels for equipment qualification, and vital access are based on scaling techniques. The scaled increase in radiation levels also includes the effect of the change in fuel cycle length and the use of current computer codes, methodology, and nuclear data in developing the uprated core and reactor coolant inventory, versus the methodology computer tools, and nuclear data used in the development of the original licensing basis core/reactor coolant inventory. Note that for the

most part, the percentage of the estimated increase that can be attributed directly to the power uprate is approximately the percentage of the core uprate.

The radiological consequences for the following design-basis accidents (DBAs) were re-analyzed to support the SPU:

- Main steamline break (MSLB)
- Locked reactor coolant pump (RCP) rotor
- Rod ejection
- Steam generator tube rupture (SGTR)
- Small-break LOCA (SBLOCA)
- Large-break LOCA (LBLOCA)
- Waste gas decay tank (GDT) rupture
- Volume control tank (VCT) rupture
- Holdup tank (HT) failure
- Fuel-handling accident (FHA)

As holder of an operating license issued prior to January 10, 1997, and in accordance with 10CFR50.67 (Reference 3) and *Standard Review Plan* (SRP) 15.0.1 (Reference 4), the accident source terms used in the IP3 SPU design-basis offsite and control room dose analyses have been revised to reflect the full implementation of alternative source terms (ASTs) as detailed in RG 1.183 (Reference 5).

The first use of the AST for IP3 involved only the postulated fuel handling accident and was reviewed and approved by the NRC in its SER for Operating License (OL) Amendment No. 215 (Reference 6). Subsequently, the radiological consequences analyses for all accidents included in the IP3 licensing basis have been revised to incorporate the AST and have been submitted to the NRC (Reference 7).

The analyses performed for the SPU have also followed the methodology outlined in RG 1.183 (Reference 5) and have utilized input assumptions consistent with the proposed nominal core power of 3216 MWt and are presented in subsection 6.11.9 of this document.

6.11.2 Regulatory Approach

Summarized below are the regulatory acceptance criteria that were used for the SPU assessments.

6.11.2.1 Normal Operation Assessments

The regulatory commitments currently associated with normal operation assessments are not affected by this application and remain applicable for the SPU assessment:

- Normal operation onsite dose rates and available shielding will meet the requirements of 10CFR20 (Reference 8) as it relates to allowable operator exposure and access control.

- Normal operation offsite releases and doses will meet the requirements of 10CFR20 and 10CFR50, Appendix I (Reference 9). Performance and operation of installed equipment as well as reporting of offsite releases and doses will continue to be controlled by the requirements of the *Technical Specifications* (Reference 10) and the *Offsite Dose Calculation Manual* (Reference 11).

6.11.2.2 Accident Assessments

The regulatory commitments associated with accident assessments are summarized below:

- Offsite doses:

  The acceptance criteria for the exclusion area boundary (EAB) and low-population zone (LPZ) doses are based on 10CFR50.67 (Reference 3) and Table 6 of RG 1.183 (Reference 5) (also noted in Table 1 of SRP 15.0.1 [Reference 4]):

  — An individual located at any point on the boundary of the exclusion area for any 2-hour period following the onset of the postulated fission product release should not receive a radiation dose in excess of the accident-specific total effective dose equivalent (TEDE) value noted in RG 1.183 (Reference 5), Table 6.

  — An individual located at any point on the outer boundary of the LPZ who is exposed to the radioactive cloud resulting from the postulated fission product release (during the entire period of its passage) should not receive a radiation dose in excess of the accident-specific TEDE value noted in RG 1.183 (Reference 5), Table 6.

  — The GDT rupture, VCT rupture, and HT failure are not specifically addressed in RG 1.183 (Reference 5). The acceptance criterion used for these events is assumed to be 0.5 rem consistent with the guidance of RG 1.26 (Reference 12). The criterion is applied as 0.5 rem TEDE to be consistent with an AST application.

- Control Room Dose: The acceptance criterion for the control room dose is based on 10CFR50.67 (Reference 3).

  — Adequate radiation protection is provided to permit occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 0.05 Sv (5 rem) TEDE for the duration of the accident.

- Equipment Qualification:

  The SPU EQ assessment takes into consideration the effect of a core power uprate using scaling techniques and TID-14844 source terms (Reference 13). This approach is acceptable, based on Section 1.3.5 of RG 1.183, which indicates that though EQ analyses affected by plant modifications should be updated to address the effects, no plant modification is required to address the effect of the difference in source term characteristics (that is, AST versus TID-14844) on EQ doses.

- Vital Area Access Doses:

  The vital area access dose assessment for the SPU takes into consideration the effect of core power uprate using scaling techniques and TID-14844 (Reference 13) source terms. This approach is acceptable based on the bench-marking study reported in SECY-98-154 (Reference 14), which concluded that results of analyses based on TID-14844 would be more limiting earlier in the event.

  The SPU assessment took into consideration the IP3-specific regulatory commitments associated with post-LOCA vital area access. In accordance with NUREG-0737, Item II.B.2 (Reference 15), each power reactor licensee was required to perform a radiation and shielding design review of spaces around systems that may, as a result of an accident, contain highly radioactive material. Additionally, each licensee was required to provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedure controls.

6.11.3 Computer Codes

The Quality Assurance (QA) Category 1 computer code used by Westinghouse to support this application is *ORIGEN2, Isotope Generation and Depletion Code – Matrix Exponential Method* (Reference 16). The referenced computer code has been used extensively to support nuclear power plant design.

6.11.4 Radiation Source Terms

6.11.4.1 Introduction

This section describes the input parameters and methodology used in the calculation of radiation source terms applicable to the IP3 SPU. Radiation source terms for several different accident- and normal-operating conditions were determined for the SPU conditions. These source terms were used as input to dose and balance-of-plant (BOP) analyses. The re-analyzed areas included the following:

- Core inventory and FHA fission product activities
- Reactor Coolant System (RCS) design basis sources
- Volume control tank sources
- Tritium sources
- Control room direct dose following a large-break LOCA
- Normal primary and secondary coolant source

Each of these source term calculations is discussed in subsequent subsections.

6.11.4.2 Core Inventory and Fuel-Handling Accident Sources

6.11.4.2.1 Input Parameters and Assumptions

The assumptions and input parameters used in the determination of the total core inventory are summarized in Tables 6.11-1 and 6.11-2.

6.11.4.2.2 Description of Analysis

Fuel burnup and fission product production were modeled using the ORIGEN2 code (Reference 16). ORIGEN2 is a versatile point-depletion and radioactive decay code for use in simulating nuclear fuel cycles and calculating the nuclide concentration and characteristics of materials contained therein. The code considers the transmutation of isotopes in the material. For the relatively high fluxes in the core region of the reactor, burn in and burn out of isotopes can have an important effect. This is particularly true for fuel cycle designs with high-burnup regions. These important effects are modeled in the ORIGEN2 calculations.

For the transition to cycles with the SPU power level, the core inventory calculation was performed for Cycles 14 through 16. The core inventory for these three cycles differed very little. For the IP3 SPU, Cycle 16 operating at the SPU power conditions was modeled in the

ORIGEN2 calculations as the base case, the case from which results were taken. The characteristics of Cycle 16 are provided in Tables 6.11-1 and 6.11-2.

The ORIGEN2 analysis for the SPU modeled a single fuel assembly from each region of the core. Burnup calculations that reflect each of the appropriate power histories were performed, and the total inventory for each region at the end of the transition cycle was then determined by multiplying the individual assembly isotopic inventory by the number of assemblies in the respective regions. Finally, the results for each region of the core were summed to produce the total core inventory.

To accommodate variations in fuel design and fuel management, a multiplier of 1.04 was applied to the core inventory of Cycle 16. A decay time of 84 hours after shutdown was used for the FHA source term. The inventory for one average fuel assembly can be obtained by dividing the core inventory by 193 assemblies.

6.11.4.2.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to various radiological evaluations.

6.11.4.2.4 Results

The total core inventories of actinide and fission product activities for use in radiological evaluations are presented in Table 6.11-3.

6.11.4.3 RCS Fission Product Activities

6.11.4.3.1 Input Parameters and Assumptions

Based on the core loading parameters in Tables 6.11-1 and 6.11-2, the parameters used in the calculation of the reactor coolant fission product concentrations, including pertinent information concerning the expected coolant cleanup flow rate, are presented in Table 6.11-4. In the RCS activity calculations, fission product escape rate coefficients were used to model a 1-percent level of small cladding defects (that is, 1 percent of the power that is being produced by fuel rods that have cladding defects) in all fuel regions for the fuel cycle.

6.11.4.3.2 Description of Analysis

The fission product inventory in the reactor coolant during operation of the fuel cycle with a 1-percent level of small cladding defects was computed. No credit was taken for fission product removal due to purge of the VCT. Furthermore, in determining the RCS inventory for individual isotopes, the maximum activity occurring at any time during the fuel cycle was documented in each case. Therefore, the total set of fission product concentrations did not represent any particular time during the fuel cycle, but rather, a composite of the maximum activity concentration exhibited by each isotope. This overall approach provided a conservative treatment of the RCS.

For fission products, effects of the following variations were estimated and included conservatively in the calculation of RCS activities:

- Lower-than-expected letdown flow
- Application of a 1.04 multiplier to calculated specific activities
- Core power increased by 2 percent for power determination uncertainty
- Low RCS mass

Tritium and corrosion product values, which are not directly related to reactor power, were taken as the greater of standard Westinghouse values or nominal values from ANSI/ANS-18.1-1999 (Reference 17).

6.11.4.3.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to radiological evaluations that are presented in subsection 6.11.9 of this report.

6.11.4.3.4 Results of Analyses

The RCS-fission product and corrosion-product specific activities are given in Table 6.11-5 and were provided as input to radiological evaluations.

6.11.4.4 Volume Control Tank Inventory

6.11.4.4.1 Input Parameters and Assumptions

The input and methods for calculating the VCT inventory are the same as those used in the RCS source calculations except that the VCT purification flow rate is based on the maximum

flow rate (132 gpm) as opposed to the nominal flow rate (45 gpm) that was used in the RCS calculations.

In addition, for Kr-85, it is assumed the Kr-85 in the VCT was in equilibrium with the RCS in accordance with Henry's Law.

6.11.4.4.2 Description of Analyses

Radiological inventories for the VCT were based on the calculation of RCS and VCT nuclide concentrations with the maximum letdown flow of 132 gpm. As with RCS activities, a multiplier of 1.04 is applied.

Values for the gas inventory in the VCT are based on a vapor volume of 266 ft^3.

6.11.4.4.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to radiological evaluations that are presented in subsection 6.11.9.

6.11.4.4.4 Results of Analyses

The VCT radionuclide inventory is given in Table 6.11-6.

6.11.4.5 Tritium Sources

6.11.4.5.1 Input Parameters and Assumptions

Tritium generation is based on the cycle design described in Tables 6.11-1 and 6.11-2; tritium release fractions to the reactor coolant are given in Table 6.11-7.

6.11.4.5.2 Description of Analysis

Tritium generation is based on a calculation of tritium generation in the active core (fuel rods and coolant water) from ternary fissions, soluble boron and lithium in the coolant, and deuterium reactions in the coolant during normal operation.

The tritium generation calculations use the reactor power level, a set of groupwise neutron fluxes, groupwise neutron reaction cross sections, and water masses in the active core region, to predict the tritium generation. The design value of release of tritium from ternary fissions to the coolant is 10 percent of generation; the expected value is 2 percent.

6.11.4.5.3 Acceptance Criteria

The results of the tritium source analysis are used to evaluate plant tritium generation and release. There are no acceptance criteria for these stand-alone calculations.

6.11.4.5.4 Results of Analyses

The calculated tritium generation and release to the reactor coolant is provided for evaluation of plant tritium releases. A summary of the results of this tritium generation and release analysis is given in Table 6.11-7.

6.11.4.6 LOCA DBA Direct Control Room Dose

6.11.4.6.1 Input Parameters and Assumptions

The assumptions and input parameters used in determining the total core inventory are summarized in Tables 6.11-1 and 6.11-2.

Other input parameters for this analysis include the reactor containment vessel and Containment Shield Building dimensions, the control room location relative to the Reactor Containment Building, the location and dimensions of selected Auxiliary Building walls and floors, and the time at which removal of gaseous activity starts. These are discussed below:

- The containment dome is a 67.5-foot radius hemisphere with a thickness of 3.5 feet of concrete.
- The cylindrical portion of the containment is treated as a 67.5-foot radius cylindrical shell with a thickness of 4.5 feet of concrete. The height of the cylinder is considered to be 145 feet.
- The containment liner has a thickness of ¼ inch of steel.
- The crane support wall has a thickness of 3 feet of concrete and is 49 feet in height.
- The shielding afforded by the control room walls and structures is equivalent to 2 feet of concrete.
- Removal of non-gaseous activity occurs at 4.0 hours (for the control room direct dose applications only).

6.11.4.6.2 Description of Analyses

The gamma radiation source within containment following a LOCA DBA is based on the RG 1.183 methodology (Reference 5) and is calculated using the ORIGEN2 computer code. Source strength is reported in units of MeV/sec and MeV, respectively.

The gamma radiation going directly from the containment into the control room was calculated using the ORIGEN2 computer code. In the calculation, the containment volume was treated as two separate source regions, that is, the containment dome and the cylindrical section of the containment. The results from these two sources were then summed to give the total normalized dose rate.

The detector point was placed at a point just inside the control room location.

6.11.4.6.3 Acceptance Criteria

The calculation provided a radiation source to be used as input to other calculations. As such, there are no specific criteria for this portion of calculated results.

6.11.4.6.4 Results of Analyses

Containment gamma radiation source strength per unit time and integrated source strength for the LOCA DBA are given in Figures 6.11-1 and 6.11-2, respectively.

The 1-month calculated direct dose in the control room is 0.273 mrem. Applying an additional 4 percent for fuel management variations gave a control room dose of 0.284 mrem.

Dose rate and dose are illustrated in Figure 6.11-3.

6.11.5 Normal Operation Dose Rates and Shielding

6.11.5.1 Introduction

Cubicle wall thickness is specified not only for structural and separation requirements, but also, to provide radiation shielding in support of radiological EQ, and to reduce operator exposure during all modes of plant operation, including maintenance and accidents.

Conservative estimates of the radiation sources in plant systems and components form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and RCS isotopic inventory

and are referred to as "design basis" source terms. The SPU will affect the isotopic inventory in the core. In addition, since the design basis RCS source term is based on 1-percent fuel defects, the SPU will result in an increase in the design basis RCS concentration.

The "expected" radiation source terms in the coolant will also be affected by core SPU. Expected source terms are less than those allowable by the plant *Technical Specifications* and are usually significantly less than the design basis source terms.

The effects of the SPU on the normal operation dose rates and the adequacy of existing shielding were evaluated to ensure continued safe operation within regulatory limits. The effect of the SPU on the normal operation component of the total integrated dose used for radiological environmental qualification is discussed in subsection 6.11.8.

6.11.5.2 Description of Analysis and Evaluations

The core SPU from 3067.4 MWt to an analyzed power level of 3216 MWt will increase the activity inventory of fission products in the core by approximately the percentage of the SPU. The radioactivity levels in the primary coolant, secondary coolant, and other radioactive process systems and components will also be affected.

The original shielding design for IP3 was based on a core power level of 3216 MWt, a traditional one-year fuel cycle and a design RCS source term based on 3216 MWt and 1-percent failed fuel. To reflect SPU conditions, new radiological source terms were developed for the core and the RCS. The SPU core inventory is based on 3280.3 MWt and a 24-month fuel cycle. The SPU design RCS source term is based on 3280.3 MWt with 1-percent failed fuel, a 24-month fuel cycle, a conservative purification flow, and an additional multiplier of 1.04 to accommodate fuel management variations. The inclusion of the 24-month fuel cycle will serve to increase the inventory of the long-lived isotopes.

The assessment of the effect of the SPU and the use of a 24-month fuel cycle on normal operation plant radiation levels as well as radiation zoning and shielding adequacy addresses the following four areas:

- Areas near the reactor vessel where the dose rate is dominated by the reactor core neutron flux during power operation and gamma radiation from the irradiated fuel and neutron activated sources during shutdown
- Areas in containment that are not in proximity to the reactor but are adjacent to the RCS sources, where the dose rate is dominated by the high-energy gammas associated with Nitrogen-16 (N-16)

- Areas near spent fuel assemblies where the dose rate is dominated by the gamma radiation from the irradiated fuel

- Areas outside the containment, where the dose rate is determined by radiation sources derived from primary coolant activity

The evaluation of the effect of the SPU on the normal operation plant radiation levels is focused on the change in the expected radiation source terms in the areas discussed above.

Since plant shielding is designed to encompass all modes of operation, including anticipated operational occurrences, the evaluation of the effect of SPU on radiation zoning and shielding adequacy is based on the change in design radiation source terms. The original design RCS activity concentration, the gamma energy emission rate, and the resulting dose rates are compared to the uprate design RCS activity concentration, the gamma energy emission rate, and the resulting dose rates. The limitations imposed by the plant *Technical Specification* on the allowed reactor coolant activity concentrations are included in the evaluation.

6.11.5.2.1 Plant Radiation Levels

For the same source-shield-detector configuration, the dose rate at a given detector point is directly proportional to the neutron/gamma flux leaking out of the source region or the volumetric gamma source strength in the source region. This flux or activity increase factor for a given radiation source is the SPU scaling factor for the expected dose rate due to that source. Note that this portion of the assessment takes into consideration that the current in-plant radiation levels already reflect the 24-month fuel cycle.

<u>Dose Rates near Reactor Vessel</u>: During normal operation, the radiation source in the reactor core is primarily made up of neutron and gamma fluxes, which are approximately proportional to the core power level.

The radiation sources during shutdown are the gamma fluxes in the core due to decay and the activation activities in the reactor internals, pressure vessel, and primary system piping walls, which also vary approximately in proportion to the core power.

Therefore, the SPU from the current licensed core power of 3067.4 MWt to the analyzed core power level of 3216 MWt is expected to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.05; that is, 3216/3067.4.

In-Containment Areas Adjacent to the RCS: During normal operation, the major radiation source in the RCS components located within containment is the high energy, short half-life, gamma emitter N-16. N-16 is produced as the oxygen (of the water moderator) is exposed to the fast neutron flux present in the reactor core. The amount of activation is defined by the fast flux level (or power density) of the core and the amount of time the moderator is resident in the core. After the moderator exits the core (and neutron field), decay of the N-16 will occur.

During shutdown, the major radiation sources in the RCS components located within containment are the deposited corrosion products on the internal surfaces and the primary coolant activity without N-16.

With the SPU, the fast neutron flux is expected to increase by approximately the percentage of uprate, that is, 5 percent. The coolant residence time in the core and the transit time are not expected to change significantly due to the SPU. Therefore, the appropriate uprate scaling factor for the areas subjected to the N-16 source is 1.05.

The deposited corrosion product activity depends on RCS chemistry and cobalt impurity in RCS and steam generator components. Assuming the water chemistry remains the same, the SPU will increase the neutron flux by approximately the percentage of uprate (5 percent) and, therefore, the equilibrium corrosion product activity and the associated shutdown dose rate is also expected to increase by 5 percent.

Areas Near Irradiated Fuels and Other Irradiated Objects: These areas include the refueling canal, the spent fuel pit, the incore instrumentation drive assembly area, and other areas housing neutron-irradiated materials. The radiation source is the gamma rays from the fission products and activation products, which are determined by the fission rate, neutron flux level and the irradiation time associated with the referenced irradiated fuels and objects.

Since both the fission products and the activation products associated with the irradiated fuels and other objects are expected to increase by approximately the percentage increase in core power, the SPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.05.

Areas Outside Containment where the Radiation Source is Derived from the Primary Coolant Activity: In most areas outside the reactor containment, the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. The reactor coolant activity is dominated by the fission products, which vary approximately in proportion to the reactor power. The neutron activated corrosion products (Co-60, Co-58, etc.) are also important radionuclides in the filters. The deposited activity of corrosion products on the pipe internal surface is a major dose contributor during the shutdown maintenance. If everything remains the same after the SPU, the RCS corrosion product concentration and the equilibrium deposited corrosion product are expected to increase by approximately the same percentage as the SPU due to the increased neutron flux level.

Since both the fission products and the activated corrosion products are expected to increase by approximately 5 percent for a core power increase from 3067.4 MWt to the analyzed power level of 3216 MWt, the SPU scaling factor for the areas outside containment where the radiation source is derived from the primary coolant activity is 1.05.

6.11.5.2.2 Radiation Zoning and Shielding Adequacy

Shielding is used to reduce radiation dose rates in various parts of the station to acceptable levels consistent with operational and maintenance requirements, and also below the limits specified in 10CFR20 (Reference 8). The shielding is designed to encompass all modes of operation, including anticipated operational occurrence. The original IP3 shielding design was based upon generalized occupancy requirements in various radiation zones of the station, and upon conservative radiation source terms in various plant systems. The occupancy requirements are not affected by the SPU. The layout and configuration of systems containing radioactivity are assumed unchanged in this SPU evaluation. This evaluation focuses on comparisons of the radiation source terms used in the original plant shielding design, (as documented in the *Updated Final Safety Analysis Report* (UFSAR) (Reference 18) Section 11.2 and its supporting documentation), to the corresponding SPU source terms.

Reactor Primary Shield: The primary shield is a reinforced concrete structure that surrounds the reactor vessel. The primary function is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel. The IP3 primary shield was designed for a reactor power of 3216 MWt. It was designed to reduce the exiting thermal neutron flux to less than 10^6 n/cm^2-sec during full power operation and the exiting gamma dose rate to less than 15 mrem/hr during shutdown.

Area dose rates during normal plant operation at 100-percent power bound those expected during all other modes of operation including shutdown and are, therefore, the basis of the dose estimates used for environmental qualification and shielding. Since the dose rates near the

reactor vessel at 100-percent power are dominated by neutron and gamma fluxes from the core fission process, the effect of the 24-month fuel cycle is insignificant.

The original calculations of neutron and gamma ray leakage fluxes from the IP3 reactor were based on a design basis core configuration that included fresh fuel (generally higher power) on the core periphery, providing the greatest contribution to neutron and gamma leakage. Review of recent IP3 fluence calculations confirms that the original design remains bounding for SPU conditions. With continued use of low leakage fuel management in the SPU design, the existing primary shielding remains adequate and the dose rates adjacent to the reactor vessel/primary wall are within the design objective.

Reactor Secondary Shielding: The secondary shield is a reinforced-concrete structure that surrounds the RCS pipes, pumps and steam generators. The secondary shield also includes the reactor containment structure and the concrete operating floor over the primary coolant loops. The primary function is to attenuate the N-16 source, which emits high-energy gammas. The secondary shield was designed to limit the full power dose rate outside the containment building to less than 0.75 mrem/hr. The original design basis reactor coolant N-16 activity is based on a core power level of 3216 MWt.

Area dose rates during normal plant operation at 100-percent power bound those expected during all other modes of operation including shutdown and are, therefore, the basis of the dose estimates used for environmental qualification and shielding. Note that due to its short half-life, the N-16 activity level is not affected by the use of 24-month fuel cycle.

Since the reactor power for the original N-16 design activity is at the analyzed SPU power of 3216 MWt, the current secondary shield is adequate for continued safe operation at the SPU power.

Fuel Handling Shielding: This shielding provides protection during all phases of removal and storage of spent fuel and control rod cluster. The design basis for refueling shielding is presented in UFSAR (Reference 18) Section 11.2.2 and Table 11.2-5, and is based on 193 fuel assemblies (for a total reactor power of 3216 MWt), a maximum full power exposure of 1000 days, and a minimum fuel removal delay time of 56 hours. The fuel handling shield was designed to insure a calculated maximum dose rate in the areas adjacent to the spent fuel pit of less than 0.75 mrem/hr.

The 24-month fuel cycle will increase the long-lived isotopes in the irradiated fuel. It will also increase the activity of those isotopes for which the thermal neutron activation production mode is important, (such as Cs-134m, Cs-134, Cs-136, Rb-86, I-130, and Sm-153), due to increased thermal neutron flux toward the end of the fuel cycle. However, this is not a significant concern

as the dose rates near the refueling canal and the spent fuel pit are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies and the gamma source from the above-mentioned neutron activation isotopes constitutes only a small percentage of the total source. It is, therefore, concluded that the current spent fuel shielding is adequate for continued safe operation at the SPU power and with a 24-month fuel cycle.

Outside Containment Shielding: In support of shielding provided outside the containment, where the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity, a review was performed of the SPU design primary coolant source terms (fission and activation products) versus the original design basis primary coolant source terms. A comparison was performed of the gamma energy emission rates by energy group for the SPU versus the original primary coolant source terms. The sources included total primary coolant, degassed primary coolant and the primary coolant noble gas source. Due to the change in isotopic compositions and gamma energy spectrum between the original and the uprated RCS fluid, the comparison was based on the dose rate shielded by 0, 1, 2, and 3 feet of concrete for representative source geometry. The SPU evaluation reflects the change in fuel cycle length, difference in computer codes used in generating the source terms, and the difference in nuclear libraries. The evaluation takes into consideration the conservative simplified modeling typically employed in shielding design and considers the operation limits imposed by the plant *Technical Specification* on the primary coolant activity.

The dose rate ratios resulting from comparison of the SPU source to the pre-SPU source for the various design basis source term and shielding configurations discussed above ranged from 1.1 to 3.3. However, since the design basis SPU primary coolant activity is a very conservative source term (that is, based on 1-percent failed fuel, a very small purification flow, a 2-percent margin for power uncertainty and an additional 4-percent margin for fuel management schemes), credit is taken for a more realistic but limiting upper bound primary coolant activity based on the plant *Technical Specification* (Reference 10).

Due to similarity in the effectiveness of removal mechanisms such as demineralizers and filters, the *Technical Specification* on the iodine concentration will control both the iodines as well as the non-gaseous radionuclides in the reactor coolant with similar effectiveness. The *Technical Specification* limit on the gross activity levels (which are dominated by noble gases and their daughters), will control the level of noble gases in the reactor coolant.

The SPU assessment indicates that the *Technical Specifications* will limit the uprated RCS and degassed RCS to less than 80 percent of the original design basis source terms. In addition, the *Technical Specification* limits on the reactor coolant gross activity will maintain the SPU RCS gas activity at approximately the original design basis source terms.

Therefore, taking into consideration the limits on reactor coolant concentrations imposed by the plant *Technical Specifications* and the conservatism in the SPU design source terms, it is concluded that the shielding design based on the original design basis primary coolant activity remains valid at the SPU condition.

6.11.5.3 Acceptance Criteria

Following the SPU, normal operation dose rates and available shielding must continue to meet those requirements of 10CFR20 (Reference 8) related to allowable operator exposure and access control.

6.11.5.4 Results and Conclusions

The SPU will affect the radiation source terms in the core and the expected radiation source terms in the coolant. Expected source terms are less than those allowable by the plant *Technical Specifications* and are usually significantly less than the design basis source terms.

Since the plant is already operating with a 24-month fuel cycle, the normal operation radiation levels are expected to increase by approximately 5 percent, that is, by the percentage of core SPU. The exposure to plant personnel and to the offsite public is also expected to increase by the same percentage.

The increase in expected radiation levels will have no significant effect on plant normal operation radiation zones and shielding adequacy. This is because the increase is offset by the:

- Conservative analytical techniques typically used to establish shielding requirements,
- Conservatism in the original design basis RCS source terms used to establish the radiation zones, and
- Plant *Technical Specifications* that limit the RCS concentrations to levels below or equal to the original design basis source terms.

Individual worker exposures will be maintained within regulatory limits by the site As-Low-As-is-Reasonably-Achievable (ALARA) Program, which controls access to radiation areas.

6.11.6 Normal Operation Annual Radwaste Effluent Releases

6.11.6.1 Introduction

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials.

Liquid Radioactive Waste: Liquids from reactor process systems, or liquids that have become contaminated with these process system liquids, are considered liquid radioactive waste. These wastes are then processed according to their purity level (boron concentration, conductivity, insoluble solids content, organic content, and activity) before being recycled within the plant, discharged to the environment, or reprocessed through the Radioactive Waste System for further purification until the dose guidelines of 10CFR50, Appendix I (Reference 9) are met.

Gaseous Radioactive Waste: Airborne particulates and gases vented from process equipment as well as the building ventilation exhaust air are considered gaseous radioactive waste. The major source of gaseous radioactive waste (processing the reactor coolant by the gas stripper and the cover gas system) is continuously decayed using separate pressurized decay tanks. It is then filtered and monitored prior to release to ensure that the dose guidelines of 10CFR50 Appendix I are not exceeded.

The design of the liquid and gaseous radwaste systems must be such that the plant is capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR20 and 10CFR50, Appendix I. (Note that actual performance and operation of installed equipment, and reporting of actual offsite releases and doses continues to be controlled by the requirements of the *IP3 Offsite Dose Calculation Manual* [Reference 11].)

The SPU does not change existing radioactive waste systems (gaseous and liquid) design, operating procedures, or waste inputs. Consequently, a comparison of releases can be made based on inventories/coolant concentrations in the RCS, and secondary side steam and water inventories and concentrations. As a result, the effect of the SPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

Based on an existing licensed core power level of 3067.4 MWt and an analyzed SPU core power level of 3216 MWt, it is expected that the radioactive effluents and consequent offsite doses will increase by approximately the percentage increase in core power, that is, approximately 5 percent.

The conservatively performed SPU analysis considered:

- The plant core power operating history during the years 1998 to 2002
- The reported effluent and dose data during that period
- NUREG-0017 (Reference 19) assumptions
- Conservative methodology

The analysis estimated the effect of operation at the analyzed core power level of 3280.3 MWt (3216 MWt plus instrument uncertainty) over that of current operation (based on the 5-year data) on radioactive effluents and consequent offsite doses.

6.11.6.2 Description of Analyses and Evaluations

The SPU will increase the activity level of radioactive isotopes in the primary and secondary coolant. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous radwaste systems where they are processed prior to discharge. As the activity levels in the primary and secondary coolant are increased, the activity level of radwaste inputs are proportionately increased. Regulatory guidance relative to methodology to be utilized to establish whether the radwaste effluent releases from a pressurized water reactor (PWR) meet the requirements of 10CFR20 (Reference 8) and 10CFR50 Appendix I (Reference 9) is provided in NUREG-0017 (Reference 19), Rev. 1.

The methodology utilized in NUREG-0017 is independent of the fuel cycle length in that, in determining the nominal coolant activities provided in NUREG-0017, isotopic concentrations from a number of plants and power levels were combined and adjusted to yield a dataset with a resulting range of uncertainty. Adjustment factors were provided to address facilities outside a nominal range in which coolant activities could be used without adjustment. The core power levels addressed for the IP3 base and SPU cases are within the range of applicability and input data that was used to develop NUREG-0017.

The IP3 annual radioactive effluent release reports for 1998 through 2002 demonstrate that the current gaseous and liquid radwaste releases from the site are well within the release/dose limits set by 10CFR20 and 10CFR50, Appendix I. The effect of the SPU on these releases was evaluated to ensure continued operation within regulatory limits.

The licensed reactor core power level of IP3 during the 1998 to 2002 time frame was 3025 MWt. The SPU assessment addresses a core power level of 3280.3 MWt. The system parameters for SPU conditions reflect the flow rates and coolant masses at an NSSS power level of 3228.5 MWt. For the pre-SPU condition, the evaluation utilized offsite doses based on an average five-year set of organ and whole body doses calculated from effluent reports for the

years 1998 through 2002, including the associated average annual core power level extrapolated to 100-percent availability. Releases occurring during periods of IP3 shutdown were conservatively lumped with operational releases and included in the doses scaled for 100-percent availability.

Using the methodology and equations found in NUREG-0017 (Reference 19) with the plant-specific parameters for the SPU case, the percentage change for activity classes in the reactor coolant and secondary coolant (water and steam) were calculated. Relative changes in the noble gas activity inventory in the reactor coolant were also calculated; this was necessary for those releases that are based on coolant inventory such as noble gas released during shutdown operations. To estimate an upper bound effect on offsite doses, the highest factor found for any chemical group of radioisotopes pertinent to the release pathway was applied to the average doses previously determined as representative of operation at pre-SPU conditions (at 100-percent availability). This was used to estimate the maximum potential increase in effluent doses due to the SPU, and to demonstrate that the estimated offsite doses following SPU, although increased, continue to remain below the regulatory limits.

6.11.6.3 Acceptance Criteria

The liquid and gaseous radwaste systems' design must be such that the plant is capable of maintaining normal operation offsite releases and doses within the requirements of 10CFR20 (Reference 8) and 10CFR50, Appendix I (Reference 9) following the SPU. (Note that actual performance and operation of installed equipment as well as reporting of actual offsite releases and doses continue to be controlled by the requirements of the *Technical Specifications* [Reference 10] and the *IP3 Offsite Dose Calculation Manual* [Reference 11].) If the resulting doses estimated after the SPU are still a small fraction of the 10CFR50 Appendix I limits, then it is reasonable to conclude that the IP3 Radioactive Waste Systems and operating procedures will meet the design objectives of 10CFR50 Appendix I.

6.11.6.4 Results and Conclusions

Results

As indicated earlier, based on an existing licensed core power level of 3067.4 MWt, and an SPU core power level of 3216 MWt, it is expected that the radioactive effluents and consequent off-site doses will increase by approximately the percentage increase in core power, that is, approximately 5 percent.

Using NUREG-0017 (Reference 19) assumptions and conservative methodology, the SPU analysis results summarized below utilize the plant operating history to estimate the effect of the

SPU on radioactive effluents and consequent offsite doses, by comparing plant operation at the SPU core power level of 3280.3 MWt (which includes margin for power uncertainty) to plant operation at 2956.15 MWt (the effective core power level during the period 1998 through 2002). The estimated doses following the SPU are presented in Table 6.11-9.

6.11.6.4.1 Expected Reactor Coolant Source Terms

Based on a comparison of base versus SPU input parameters, and the methodology outlined in NUREG-0017 (Reference 19), the maximum expected increase in the reactor coolant source is approximately 12.1 percent for noble gases and 11 percent for other long half-life activity. The above change is primarily due to the estimated decrease in RCS mass (~1 percent) and increase in effective core power level (~11 percent, that is, 3280.3 MWt [uprate power level]/2956.15 MWt [average power level during 1998 - 2002) between pre- and post-SPU conditions. Considering the accuracy and error bounds of the operational data used in NUREG-0017, this percentage is well within the uncertainty of the existing NUREG-0017-based expected reactor coolant isotopic inventory used for radwaste effluent analyses.

6.11.6.4.2 Liquid Effluents

As discussed above, there is a maximum 11-percent increase in the liquid releases as input activities are based on long-term RCS activity (the relative increase of I-131 in the RCS is limiting—the maximum increase of cesiums and other nuclides is 11 percent), which is proportional to the SPU percentage increase, and on waste volumes that are essentially independent of power level within the applicability range of NUREG 0017. Tritium releases in liquid effluents are assumed to increase approximately 11 percent (corresponding to the effective core SPU percent), since the analysis identifies changes in an existing facility's power rating without changing its mode of operation.

6.11.6.4.3 Gaseous Effluents

For all noble gases, there will be a bounding maximum 12.1-percent increase in effluent releases due to the effective core SPU percentage increase. Gaseous effluents have two components: one is based on RCS inventory and results in an 11-percent increase and the other is based on concentration (due primarily to differences in RCS masses and the increase in effective core power level between the pre- and post-SPU conditions), which would result in a 12.1-percent increase. The limiting increase will be used for this evaluation, that is, 12.1 percent.

In actuality, gaseous releases of Kr-85 will increase by approximately the percentage of power increase (~11 percent). Gaseous isotopes with shorter half-lives will have increases slightly

greater than the effective percentage increase in power level up to a bounding value of 12.1 percent.

Tritium releases in the gaseous effluents increase in proportion to their increased production, which is directly related to core power and is allocated in this analysis in the same ratio as pre-SPU releases.

The effect of the SPU on iodine releases is approximated by the effective power level increase and calculated increase in I-131 RCS concentration of 11 percent.

For particulates, the methodology of NUREG-0017 (Reference 19) specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the Turbine Building from main steam leaks and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Thus, minimal change would be expected for the SPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the "source" of particulates or iodines released. In addition, tritium is included in the category of iodines and particulates. On the secondary side, moisture carryover (MCO) is a major factor in determining the non-volatile activity in the steam. The multiplier applicable to the particulates released via the Turbine Building due to main steam leaks and air ejector exhaust is higher than the percentage of the SPU (primarily due to an estimated five-fold increase in MCO due to the SPU, coupled with an 11-percent increase in coolant concentration). However, the contribution of particulates to the "Iodine and Particulate" category was insignificant to the dose contribution from iodine or tritium. For these two species, iodine had the greater increase due to the addition of MCO to that of the volatile component resulting in a 12.3-percent increase in steam activity, while the tritium increase was bounded by the increase in power. Thus, the scaling factor for the entire category was conservatively estimated at 12.3 percent.

6.11.6.4.4 Solid Radioactive Waste

Though solid radwaste is not specifically addressed in 10CFR50, Appendix I (Reference 9), for completeness relative to radwaste assessments, the effect of SPU on solid radwaste generation is summarized below.

For a new facility, the estimated volume and activity of solid waste is linearly related to the core power level. However, for an existing facility that is undergoing power uprate, the volume of solid waste is not expected to increase proportionally, since the power uprate neither appreciably affects installed equipment performance, nor does it require drastic changes in system operation or maintenance. Only minor, if any, changes in waste generation volume are expected. However, it is expected that the activity levels for most of the solid waste would

increase proportionately to the increase in long half-life coolant activity bounded by the effective increase in core power, that is, 11 percent.

Thus, while the total long-lived activity contained in the waste is expected to be bounded by the percentage, 11 percent, for SPU, the increase in the overall volume of waste generation resulting from the SPU is expected to be minor.

Conclusion

As discussed in subsection 6.11.6.3, under Acceptance Criteria, the commitment is to both 10CFR20 (Reference 8) and 10CFR50 Appendix I (Reference 9), however, 10CFR50 Appendix I is more limiting. 10CFR20 does have a release rate criteria that does not exist in 10CFR50 Appendix I, but as noted in subsection 6.11.6.3, the plant *Technical Specifications* (Reference 10) and the *IP3 Offsite Dose Calculation Manual* (Reference 11) control actual performance and operation of installed equipment and releases thus maintaining compliance with that aspect of 10CFR20.

In summary, and as documented in Table 6.11-9, the estimated doses due to annual radwaste effluent releases following the SPU remain a small percentage of the allowable 10CFR50 Appendix I limits. Therefore, it is concluded that, following the SPU, the liquid and gaseous radwaste effluent treatment system will remain capable of maintaining normal operation offsite doses within the requirements of 10CFR50, Appendix I.

6.11.7 Post-Accident Access to Vital Areas

6.11.7.1 Introduction

In accordance with NUREG-0578, 2.1.6.b (Reference 20) and NUREG-0737, II.B.2 (Reference 15), vital areas are those areas within the station that will or may require access or occupancy to support accident mitigation or recovery following a LOCA. In accordance with the above regulatory documents, all vital areas and access routes to vital areas, must be designed such that operator exposure remains within regulatory limits. NUREG 0737, II.B.3 identifies NRC requirements relative to operator exposure while performing post-accident sampling.

This section focuses on areas that may require infrequent access following a LOCA. Areas that require continuous occupancy, such as the control room and Technical Support Center, are addressed later in subsection 6.11.9 of this report.

The vital access shielding review that supports IP3 licensing basis relative to post-LOCA accessibility is documented in United Engineers & Constructors (UE&C) Report, *Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems which May Be Used in Post Accident Conditions*, (Reference 21). Post-LOCA accessibility based on the estimated radiation levels versus time was evaluated for about sixteen areas in the plant. This assessment was conservatively based on a power level of 3216 MWt and a traditional 1-year fuel cycle length. The NRC review of the referenced UE&C Report and plant modifications is documented in the NRC Inspection Report 50-286/83-05 (Reference 22). NRC acceptance of the IP3 actions taken or planned for post-accident vital area access is documented in SER, NUREG-0737, Item II.B.2. (Reference 23).

A finalized report (Report No. 6604-182-S-D-001, Revision 1), reflecting revised accessibility assessments resulting from the installation of some of the proposed modifications was issued by UE&C in August 1985 (Reference 24). As a result of the plant modifications/procedure updates, operator access requirements were reduced from the previous sixteen to eight locations. In accordance with NUREG 0737 II.B.2 (Reference 23), the evaluation focused on the de-pressurized LOCA.

Subsequent to the issuance of the final UE&C Report, and as a result of other plant modifications, additional operator access requirements have been identified and operator exposure resulting from these access requirements have been analyzed. These analyses are based on a power level of 3025 MWt. The core activity used for the containment airborne source is based on a fuel irradiation period of 830 days. The sump water source is based on a 24-month fuel cycle.

In addition, per the NRC SER related to Amendment No 210 (Reference 25), the need to have, maintain, and utilize the post-accident sampling system to support emergency response decision-making has been eliminated. Consequently, the IP3 licensing basis no longer includes areas associated with post-LOCA sampling and analyses as vital areas that need post-accident access.

The above documents were reviewed to assess the effect of operation at an analyzed SPU core power level of 3280.3 MWt and a 24-month fuel cycle on post-LOCA accessibility. In addition, and as part of the SPU evaluation, the above composite list of vital access requirements were reviewed against the Emergency Operations Procedures (EOPs) to develop a current validated list of vital area access requirements essential for accident mitigation and safe shutdown.

The SPU assessment addresses the impact on operator doses due to changes in the required time for the ECCS switchover to hot-leg recirculation following a LOCA. The current IP3 design allows all recirculating sump fluids to remain inside containment until T=14hours, which is the

current time for ECCS switchover to hot-leg recirculation. The above change, which is caused by the use of an updated methodology at IP3 for boron precipitation evaluations, will result in sump fluids being recirculated outside containment starting from T=6.5 hours, instead of from T=14 hours.

The vital access dose assessment for SPU uses scaling techniques and TID-14844 (Reference 13) source terms.

6.11.7.2 Description of Analysis and Evaluations

The effect of the SPU on the radiation doses received while accessing or occupying vital areas during post-LOCA conditions is evaluated based on a comparison of the original design basis source terms to the SPU source terms.

The SPU post-LOCA gamma radiation dose rates at IP3 are compared to the gamma source terms based on the original core inventory used to develop the post-LOCA dose rates at IP3. The approach uses scaling techniques based on a source term comparison, rather than developing new dose rate estimates at the various locations, using the new core inventory.

The SPU will increase the activity level in the core by the percentage of the uprate. The estimated radiation source terms in equipment and structures containing post-accident fluids, and the corresponding post-LOCA environmental dose rates, will increase by the percentage of the SPU relative to the power level used in the analyses of record. Additional factors that can affect the equilibrium core inventory and consequently, the estimated operator dose are fuel enrichment and burnup. Theoretically, with all things being equal, the post-LOCA environmental gamma dose rates and the operator dose per identified mission should increase, as a worst case, by approximately 13 percent, that is:

$$3280.3 \text{ MWt} \times 1.04 / 3025 \text{ MWt}, = 1.13$$

Note: The multiplier of 1.04 was applied to the SPU inventory as a factor to account for variation in fuel design parameters.

However, because the uprated core reflects extended burnup and the more advanced fuel burnup modeling/libraries used in development of the uprated core, as compared to the computer code used in the original analyses, the calculated SPU scaling factor (SF) values will deviate from the core power ratio.

Radiological source terms for both the pre-SPU and SPU cases were developed for the following post accident sources discussed in the

- Final UE&C report documenting the original licensing basis:
  - Containment atmosphere, sprays not credited (100-percent noble gases and 25-percent halogens)
  - Sump water (50-percent halogens and 1-percent remainder solids)
- Subsequent analyses supporting additional assess requirements:
  - Containment atmosphere, sprays credited (the most limiting mixture that ranges from 100-percent noble gas and 50-percent halogens to 100-percent noble gas, and ~1-percent halogens)
  - Filters (halogens only)
  - Sump water (50-percent halogens and 1-percent remainder solids)

For the "unshielded" case, the factor effects on post-accident gamma dose rates were estimated by ratioing the gamma energy release rates weighted by the flux-to-dose-rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level. To address outside containment locations, the unshielded values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 Kev, which will be substantially attenuated by any piping sources.

To evaluate the factor effect of the SPU on post-LOCA gamma dose rates (versus time) in areas that are shielded, the pre-SPU and SPU source terms discussed above were weighted by the concrete shielding factors for each energy group. The concrete shielding factors, for 1 and 3 feet of concrete, provided a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time for both original design and SPU cases.

The original licensing basis assessment documented in the UE&C Report conservatively did not credit the delay in the ECCS switchover to hot-leg recirculation. However, credit was taken for this delay in the subsequent vital access assessments. The impact of the change in time of ECCS switchover to hot-leg recirculation on the unshielded post-accident radiation dose rates and operator dose estimates in the subsequent analyses is developed by ratioing the total gamma energy release rates (weighted by the energy-specific flux-to-dose rate conversion

factor) for the SPU sump fluids at the time of interest (for example, 6.5 hrs) to the weighted SPU sump water source terms at 14 hours multiplied by the estimated dose rate at T=14 hours. To address the impact of shielding, the source terms discussed above are weighted by the concrete shielding factors for each energy group and summed across all energy groups. The concrete shielding factors for 1 and 3 feet of concrete provide a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time.

6.11.7.3 Acceptance Criteria

- In some cases, the vital area assessment establishes expected operator mission doses. For those cases, the SPU acceptance criterion is to demonstrate continued compliance with the operator exposure dose limits of 5 rem noted in NUREG 0737, II.B.2 following SPU.

- For other cases, the vital area assessment establishes radiation levels in the area, but does not develop operator mission doses. For these cases, the SPU analysis will provide the estimated radiation levels following SPU. There are no acceptance criteria for this case. The licensing bases for such cases is availability of the radiation dose rate information such that the licensee can factor this information into any post-accident access planning.

6.11.7.4 Results and Conclusions

Results

Provided below is the effect of SPU including initiation of ECCS switchover to hot-leg recirculation at 6.5 hrs.

- Operator exposure during vital area access: At IP3, vital area access is required during the time period of T=30 mins to T=6.5 hrs (that is, prior to initiation of ECCS switchover to hot-leg recirculation). The bounding scaling factor for post-LOCA dose rates was used in the SPU assessment. The operator exposure during these vital missions will remain within the regulatory limit of 5-rem whole body following SPU.

- Post-LOCA accessibility in the PAB determined via radiation dose rate maps versus time. These post-LOCA radiation dose rate zone maps can be used for planning purposes relative to post-accident vital area access. Each zone represents a range of dose rates covering a decade (for example, 10E2 to 10E3 mrem/hr). These zone maps will not be affected by the SPU, since the percentage increase in source terms between the currently analyzed basis (power level of 3280 MWt with sump water sources, based

on a 24-month fuel cycle and the remaining sources based on a fuel irradiation cycle of 830 days), and the uprated power level (3280.3 MWt and a 24-month fuel cycle), is considered to be well within the error margin of the radiation dose rate zones depicted in the maps. The T=12 hour radiation dose rate map is impacted due to the change in time for ECCS switchover to hot-leg recirculation from T=14 hours to T=6.5 hours. The remaining radiation dose rate maps are not impacted since there are no other radiation dose rate maps within this time interval.

Conclusions

It is concluded that following SPU and change in time for ECCS switchover to hot-leg recirculation, the post-LOCA vital area operator dose estimates will remain within the regulatory limit of 5-rem whole body listed in NUREG-0737 II.B.2.

6.11.8 Radiological Environmental Qualification

6.11.8.1 Introduction

In accordance with 10CFR50.49 (Reference 26) safety-related electrical equipment must be qualified to survive the radiation environment at their specific location during normal operation and during an accident.

The effect of SPU on the normal operation and post-accident radiation environmental dose estimates supporting environmental qualification is summarized in this section.

Post-accident environmental doses are usually developed based on the equilibrium core inventory assuming full-power operation at the licensed power level plus margin, source term guidance available from regulatory documents relative to post-accident core releases, and plant-specific mitigation system design features and layout. The SPU affects the equilibrium core inventory and, therefore, the post-accident radiological source terms. Additional factors that can affect the equilibrium core inventory are fuel enrichment and burnup.

The SPU assessment addresses the impact on post-LOCA radiological environmental levels due to changes in the required time for ECCS switchover to hot-leg recirculation following a LOCA. The current IP3 design allows all recirculating sump fluids to remain inside containment until T=14 hours, which is the current time for ECCS switchover to hot-leg recirculation. The above change, which is caused by the use of an updated methodology at IP3 for boron precipitation evaluations, will result in sump fluids being recirculated outside containment starting from T=6.5 hours, instead of from T=14 hours.

For purposes of equipment qualification, IP3 is divided into various environmental zones. The radiological environmental conditions noted for these zones are the maximum conditions expected to occur and are representative of the whole zone. The normal operation doses represent 40 years of operation. The accident environmental doses in areas that are considered harsh from a radiological standpoint are based on a LOCA. Integrated doses are provided up to a period of one year after the accident.

Accident Environments

The post-accident dose rate and integrated dose information relative to both the gamma and beta radiation environments inside and outside containment are based on a power level of 3280 MWt. The core activity used for the containment airborne source is based on a fuel irradiation period of 830 days. The sump water source is based on a 24-month fuel cycle.

The radiation sensitive portions of safety-related electrical equipment located outside containment are contained in leak tight enclosures, are shielded, or are enclosed in such a way that the beta dose contribution from airborne radioactivity is negligible. Based on this, post-LOCA beta environments are not applicable outside containment.

Normal Operation Environments

The normal operation gamma radiation dose rate and 40-year integrated dose are based on survey data.

6.11.8.2 Description of Analysis and Evaluation

Post-Accident Radiological Environments

The SPU will increase the activity level in the core by the percentage of the uprate. The estimated radiation source terms in equipment and structures containing post-accident fluids, and the corresponding post-LOCA environmental dose rates, will increase by the percentage of the uprate relative to the power level used in the analyses of record. However, because the SPU core reflects extended burnup and the more advanced fuel burnup modeling/libraries used in development of the uprated core, as compared to the computer code used in the original analyses, the calculated uprate scaling factor values will deviate from the core power ratio.

Radiological source terms for both the pre-SPU and the SPU cases were developed for the various post-accident sources addressed in the IP3 analyses of record supporting radiological equipment qualification.

The following core release fractions were considered in developing SPU scaling factors:

- The most limiting mixture that ranges from 100-percent noble gas and 50-percent halogens to 100-percent noble gas and ~1-percent halogens.
- Halogens only
- 50-percent halogens and 1-percent remainder solids

For the "unshielded" case, the post-LOCA gamma dose rate scaling factors were estimated by ratioing the gamma energy release rates (Mev/sec) weighted by the flux-to-dose-rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level. To address outside containment locations, the unshielded values included the shielding effect of a pipe wall thickness associated with a 2-inch nominal diameter pipe. This ensures that the results are not skewed by photons at energies less than 25 Kev, which will be substantially attenuated by any piping sources.

The post-LOCA gamma dose rate scaling factors (versus time) in areas that are shielded, were determined by weighting the pre-SPU and the SPU source terms discussed above by the concrete shielding factors for each energy group. The concrete shielding factors, for 1 and 3 feet of concrete provided a basis for comparison of the post-LOCA spectrum hardness of source terms with respect to time for both original design and SPU cases.

Similar calculations were performed to estimate the gamma dose scaling factors, that is, unshielded scaling factors were estimated by ratioing the integrated gamma energy release (Mev-hr/sec) weighted by the flux to dose rate conversion factor, as a function of time, for the SPU power level, to the corresponding weighted source terms based on the pre-SPU power level; whereas the shielded scaling factors were determined by weighting the pre-SPU and the SPU integrated gamma energy release discussed above by the concrete shielding factors for each energy group.

The impact of the change in the time of ECCS switchover to hot-leg recirculation on the post-accident integrated doses is developed as follows. The SPU sump water activity (curies) is integrated from 6.5 hours and from 14 hours to 1-year post-LOCA, and converted to cumulative energy releases (Mev-hr/sec) versus time for the two integration sets. The two sets of energy releases are multiplied by weighting factors per energy group for a no-shield, moderately shielded, and heavily shielded source to detector geometry, and summed across all energy groups. The weighted cumulative energy release that begins at 6.5-hours after the LOCA is divided by the weighted cumulative energy release that begins at 14 hours after the LOCA for each time interval. The ratio at each interval that results in the maximum value for the three

conditions (that is, no-shield, moderately shielded, and heavily shielded source to detector geometry), is then conservatively chosen as the integrated dose-scaling factor for that interval.

The beta dose/dose rate scaling factor was simply a ratio of the dose or dose rate developed with the SPU core activity and the dose or dose rate developed with the pre-SPU core activity as a function of time after a LOCA.

Normal Operation Radiation Environments

New surveys performed by Entergy in each of the zones confirmed the continued validity of the existing data for uprated conditions.

6.11.8.3 Acceptance Criteria

The equipment in the IP3 EQ Program must be qualified to actively function, and/or not impair other equipment relied on to perform an active safety function in the radiation environment to which they are exposed during normal operation as well as for the duration of the accident. This section establishes the new radiation environments following SPU.

6.11.8.4 Results and Conclusions

The existing normal operation radiation environmental levels remain valid at SPU conditions.

To qualify for post-accident radiological environments, IP3 utilizes the 1-year integrated dose. The current one-year integrated doses in TSP-011 are increased by 10 percent as a result of the SPU and the earlier ECCS switchover to hot-leg recirculation.

6.11.9 Radiological Consequences Evaluations (Doses)

6.11.9.1 Introduction

The radiological consequences for the following DBAs were re-analyzed to support the SPU:

- Main steamline break (MSLB)
- Locked RCP rotor
- Rod ejection
- Steam generator tube rupture (SGTR)
- Small-break LOCA (SBLOCA)
- Large-break LOCA (LBLOCA)
- Waste gas decay tank (GDT) rupture

- Volume control tank (VCT) rupture
- Holdup tank (HT) failure
- Fuel-handling accident (FHA)

The accident source terms used in the IP3 SPU design-basis offsite and control room dose analyses reflect the full implementation of ASTs as detailed in RG 1.183 (Reference 5).

The first use of the AST for IP3 involved only the postulated fuel handling accident and was reviewed and approved by the NRC in its SER for Operating License (OL) Amendment No. 215 (Reference 6). Subsequently, the radiological consequences analyses for all accidents included in the IP3 licensing basis have been revised to incorporate the AST and have been submitted to the NRC (Reference 7).

The analyses performed for the SPU follow the methodology outlined in RG 1.183 (Reference 5). The analyses have been updated using input assumptions consistent with the proposed nominal core power of 3216 MWt and are presented in this section.

For each accident, the TEDE doses are determined at the site boundary (SB) for the limiting 2-hour period, at the LPZ boundary for the duration of the accident, and in the control room for 30 days.

6.11.9.1.1 General Input Parameters and Assumptions

The assumptions and inputs described in this section are common to various analyses discussed in the following sections. These assumptions and inputs are consistent with those submitted to the NRC (Reference 7) except as revised to reflect plant operation at the SPU power. Each accident and the specific input assumptions are described in detail in subsections 6.11.9.2 through 6.11.9.11.

The TEDE dose is equivalent to the committed effective dose equivalent (CEDE) from inhalation and the deep dose equivalent (DDE) from external exposure. Effective dose equivalent (EDE) is used in lieu of DDE in determining the contribution of external dose to the TEDE consistent with RG 1.183 (Reference 5) guidance. The dose conversion factors (DCFs) used in determining the CEDE dose are from the Environmental Protection Agency (EPA) Federal Guidance Report No. 11 (Reference 27). The DCFs used in determining the EDE dose are from the EPA Federal Guidance Report No. 12 (Reference 28). The nuclide decay constants are derived from half-lives reported in EPA Federal Guidance Report No. 11 (Reference 27). The nuclide data are listed in Table 6.11-10.

The offsite breathing rates and the offsite atmospheric dispersion factors used in the offsite radiological calculations are provided in Table 6.11-11.

Parameters modeled in the control room personnel dose calculations are provided in Table 6.11-12. These parameters include normal operation flow rates, emergency operation flow rates, control room volume, filter efficiencies, and control room operator breathing rates. Atmospheric dispersion factors are event-dependent and are listed together with the assumptions for each accident. The control room dose acceptance limit from 10CFR50.67 (Reference 3) is 5-rem TEDE.

Subsection 6.11.4 of this report describes the calculation of the core and coolant activity. The core fission product activity modeled in the radiological consequences analyses for the locked rotor, rod ejection, SBLOCA, and LBLOCA is provided in Table 6.11-13, and was calculated by modeling the third transition cycle. To accommodate variations in fuel design and fuel management, a multiplier of 1.04 was applied to the core inventory. The core activity data in Table 6.11-13 include this multiplier. The nominal reactor coolant activity based on 1-percent fuel defects is provided in Table 6.11-14. A 1.04 multiplier was applied to the coolant activity. The reactor coolant and secondary coolant iodine activities modeled in the radiological consequences analyses, based on the *Technical Specification* limits for dose equivalent I-131 (DE I-131), are provided in Table 6.11-15.

6.11.9.1.2 Iodine Spiking Models

A number of accident analyses take iodine spiking into consideration (for example, MSLB and SGTR).

For the pre-existing iodine spike, it was assumed that a reactor transient occurs prior to the accident and raises the primary coolant iodine concentration to 60 µCi/gm of DE I-131. (This is the *Technical Specification* limit for transient elevated iodine activity in the primary coolant.) For the accident-initiated iodine spike, it was assumed that the reactor trip associated with the accident creates an iodine spike, which increases the iodine release rate from the fuel to the reactor coolant. The spike iodine release rate is a multiple of the maximum equilibrium release rate (where the equilibrium release rate is that rate corresponding to maintaining a primary coolant concentration of 1.0 µCi/gm of DE I-131, which is the maximum concentration allowed by the *Technical Specifications* for continuous operation). RG 1.183 (Reference 5) requires a spike multiplier of 500 for the steamline break, and allows a multiplier of 335 for the SGTR.

The primary coolant iodine concentrations associated with a pre-existing iodine spike are provided in Table 6.11-15, and the iodine appearance rates associated with an accident-initiated iodine spike are provided in Table 6.11-16.

6.11.9.2 Main Steamline Break Radiological Consequences

In this analysis, a complete severance of a main steamline outside containment is assumed to occur. The affected steam generator rapidly depressurizes and releases iodine activity initially contained in the secondary coolant and primary coolant activity (iodines and noble gases) transferred via steam generator tube leaks, directly to the outside atmosphere. A portion of the iodine activity initially contained in the intact steam generators and the activity transferred to the secondary coolant due to tube leakage is released to the atmosphere through either the atmospheric relief valves (ARVs) or the safety valves. The steamline break outside containment bounds any break inside containment since the outside containment break provides a means for direct release to the environment. This section describes the assumptions and analyses performed to determine the offsite and control room doses resulting from the release of activity associated with this event.

6.11.9.2.1 Input Parameters and Assumptions

The major assumptions and parameters used in this analysis are itemized in Table 6.11-17.

The analytical methods and assumptions outlined in RG 1.183 (Reference 5) were used in the analysis of the MSLB radiological consequences. The activity available for release to the environment included the iodine assumed to be initially present in the secondary coolant and the activity in the primary coolant (both iodine and noble gases) that could leak into the secondary coolant due to steam generator tube leakage.

Source Term

The iodine activity concentration of the secondary coolant at the time an MSLB occurs was assumed to be equivalent to the *Technical Specification* (Reference 10) limit of 0.10 μCi/gm of DE I-131.

The MSLB event was analyzed for two iodine spiking cases: one in which there is a pre-existing iodine spike resulting in elevated primary coolant activity, and the other in which an iodine spike is assumed to be initiated by the accident. For the pre-accident iodine spike case, it was assumed that a reactor transient occurs prior to the MSLB and raises the RCS iodine concentration to the *Technical Specification* limit for a transient of 60 μCi/gm of DE I-131. For the accident-initiated iodine spike case, the reactor trip associated with the MSLB creates an iodine spike in the RCS that increases the iodine release rate from the fuel to the RCS to a value 500 times greater than the release rate corresponding to a maximum equilibrium RCS concentration of 1.0 μCi/gm of DE I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8 percent

of the iodine in the fuel-cladding gap, the gap inventory is depleted within 3 hours, and the accident-initiated spike is terminated at that time.

The noble gas activity concentration in the RCS at the time the accident occurs is based on operation with a fuel defect level of 1.0 percent.

Release Pathway

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 432 gpd for any one steam generator, and a total of 1440 gpd for all steam generators combined.

The steam generator connected to the broken steamline was assumed to boil dry within 5 minutes following the MSLB. The entire liquid inventory of this steam generator was assumed to be steamed off and all of the iodine that was initially in this steam generator was assumed to be released to the environment. Also, iodine carried over to the faulted steam generator by tube leakage was assumed to be released directly to the environment, with no credit taken for iodine retention in the steam generator.

An iodine partition factor in the intact steam generators of 0.01 (curies [Ci] iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent loss-of-offsite power (LOOP), an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

At 29 hours after onset of the accident, the Residual Heat Removal System (RHRS) was assumed to remove all decay heat, and there were no further steam releases to the atmosphere from the intact steam generators.

Within 72 hours after the event, analysis showed that the RCS had been cooled to below 212°F, and there were no further steam releases to the atmosphere from the faulted steam generator.

No fuel failure (departure from nucleate boiling [DNB] or melt) was calculated to occur for the MSLB event.

Control Room Isolation

In the event of an MSLB, the low steamline pressure safety injection (SI) setpoint will be reached almost immediately after event initiation. The SI signal causes the control room heating, ventilation, and air conditioning (HVAC) to switch from the normal-operation mode to the emergency-operation mode. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 1 minute after event initiation.

6.11.9.2.2 Acceptance Criteria

The offsite dose limit for an MSLB with a pre-accident iodine spike is 25-rem TEDE per RG 1.183 (Reference 5), which is also the guideline value of 10CFR50.67 (Reference 3). For an MSLB with an accident-initiated iodine spike, the offsite dose limit is 2.5-rem TEDE per RG 1.183. This is 10 percent of the guideline value of 10CFR50.67. The limit for the control room dose is 5-rem TEDE per 10CFR50.67 for both iodine spiking cases.

6.11.9.2.3 Results and Conclusions

The calculated doses due to the MSLB with a pre-existing iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
Pre-Accident Iodine Spike – SB	0.2	25
Pre-Accident Iodine Spike – LPZ	0.3	25
Pre-Accident Iodine Spike - Control Room	0.6	5

The calculated doses due to the MSLB with an accident-initiated iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
Accident-Initiated Iodine Spike - SB	0.5	2.5
Accident-Initiated Iodine Spike - LPZ	0.8	2.5
Accident-Initiated Iodine Spike - Control Room	2.1	5

The acceptance criteria are met.

The SB doses reported are for the worst 2-hour period. This period is from 0 to 2 hours for the pre-accident iodine spike and from 3 to 5 hours for the accident-initiated iodine spike.

6.11.9.3 Locked Rotor Accident

In this analysis, an instantaneous seizure of an RCP rotor is assumed to occur, which rapidly reduces flow through the affected reactor coolant loop (RCL). Fuel cladding damage could be predicted as a result of this accident. Due to the pressure differential between the primary and secondary systems and assumed steam generator tube leakage, fission products transfer from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through either the ARVs or safety valves. In addition, iodine activity is contained in the secondary coolant prior to the accident, and some of this activity is assumed to be released to the atmosphere as a result of steaming from the steam generators following the accident.

6.11.9.3.1 Input Parameters and Assumptions

The major assumptions and parameters used in the analysis are itemized in Table 6.11-18.

The analysis of the locked-rotor radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

Source Term

The analysis of the locked-rotor radiological consequences assumed an iodine concentration of 1.0 μCi/gm of DE I-131 in the primary coolant prior to the accident.

The noble gas and alkali metal activity concentration in the primary coolant when the postulated accident occurs is based on a fuel defect level of 1 percent. The iodine activity concentration of the secondary coolant when the locked rotor occurs is assumed to be 0.10 μCi/gm of DE I-131. The alkali metal activity concentration of the secondary coolant at the time the locked rotor occurs is assumed to be 10 percent of the primary side concentration.

The transient analysis performed for the SPU (subsection 6.3.14 of this report) shows that no rods in DNB are calculated for the locked-rotor event. However, it was conservatively assumed that 5 percent of the fuel rods in the core suffered damage sufficient that all of their gap activity was released to the RCS. Eight percent of the total I-131 core activity, 10 percent of the total Kr-85 core activity, 5 percent of the total core activity for other noble gases and other iodines, and 12 percent of the total core activity for alkali metals were assumed to be in the fuel-cladding gap and released into the primary coolant. In the calculation of the activity releases from the failed fuel, the maximum radial peaking factor of 1.7 was applied.

Release Pathway

Activity is released to the environment by way of primary-to-secondary leakage and steaming from the secondary side to the environment. The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day.

The RHRS was assumed to remove all decay heat 29 hours into the accident, with no further releases to the environment after that time.

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent loss-of-offsite-power (LOOP), an iodine removal factor of 0.01 could have been taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited by MCO. The bounding value for MCO is 0.10 percent, therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

Control Room Isolation

It was assumed that the control room HVAC System begins in normal-operation mode, and as activity builds up in the control room, a high-radiation signal is generated. It was conservatively assumed that there is a 20-minute operator action time to switch the control room HVAC to the emergency mode of operation after the high radiation signal. For this analysis, this was modeled at 32 minutes.

6.11.9.3.2 Acceptance Criteria

The offsite dose limit for a locked rotor accident is 2.5-rem TEDE per RG 1.183 (Reference 5). This is 10 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.3.3 Results and Conclusions

The calculated doses due to the locked rotor event are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	1.1	2.5
LPZ	1.4	2.5
Control Room	2.5	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 27 to 29 hours after event initiation.

6.11.9.4 Rod Ejection Accident

For this analysis, it is assumed that a control rod drive mechanism (CRDM) pressure housing mechanical failure occurs, resulting in the ejection of a rod cluster control assembly (RCCA) and drive shaft. As a result of the accident, some fuel cladding damage and a small amount of fuel melting (pellet centerline) are assumed to occur. Due to the pressure differential between the primary and secondary systems, radioactive primary coolant is assumed to leak from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere through the main condenser, the ARVs, or the safety valves. Also, iodine and alkali metal group activity is contained in the secondary coolant prior to the accident, and some of this activity is released to the atmosphere as a result of steaming from the steam generators following the postulated accident. Finally, radioactive primary coolant is discharged to the containment via spill from the opening in the reactor vessel head. A portion of this radioactivity is released through containment leakage to the environment.

6.11.9.4.1 Input Parameters and Assumptions

Separate calculations were performed to calculate the dose resulting from the release of activity to containment and subsequent leakage to the environment and the dose resulting from the leakage of activity to the secondary system and subsequent release to the environment. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths.

A summary of input parameters and assumptions is provided in Table 6.11-19.

The analysis of the rod ejection radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

Source Term

The assumption is that less than 10 percent of the fuel rods in the core undergo DNB as a result of the rod ejection accident. In determining the offsite doses following a rod ejection accident, it was conservatively assumed that 10 percent of the fuel rods in the core suffer sufficient damage so that all of their gap activity is released. Ten percent of the total core activity of iodine and noble gases and 12 percent of the total core activity for alkali metals were assumed to be in the fuel-cladding gap. In the calculation of activity released from the failed/melted fuel, the maximum radial peaking factor of 1.7 was applied.

A small fraction of the fuel in the failed fuel rods was assumed to melt as a result of the rod ejection accident. This amounts to 0.25 percent of the core, with the melting assumed to take place in the centerline of the affected rods. Of the rods that entered DNB, 50 percent were assumed to experience some fuel melting (5.0 percent of the core). Of the rods that experience melting, 50 percent of the axial length of the rod was assumed to melt (2.50 percent of the core). It was further assumed that only 10 percent of the radial portion of the rod melts (0.25 percent of the total core).

For both the containment leakage release path and the primary-to-secondary leakage release path, it was assumed that all noble gas and alkali metal activity released from the failed fuel (both gap activity and melted fuel activity) was available for release. For the containment leakage release path, it was assumed that all of the iodine released from the gap of failed fuel and 25 percent of the activity released from melted fuel was available for release from containment. For the primary-to-secondary leakage release path, it was assumed that all of the iodine released from the gap of failed fuel and 50 percent of the activity released from melted fuel was available for release from the RCS.

Prior to the postulated accident, the iodine activity concentration of the primary coolant was assumed to be 1.0 μCi/gm of DE I-131. The noble gas and alkali metal activity concentrations in the RCS when the rod ejection accident was postulated to occur were based on operation with a fuel defect level of 1 percent. Further, the iodine activity concentration of the secondary coolant was assumed to be equivalent to 0.10 μCi/gm of DE I-131, and the alkali metal activity concentration of the secondary coolant was assumed to be 10 percent of the primary side concentration.

Iodine Chemical Form

Iodine in containment was assumed to be 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. Iodine released from the secondary system was assumed to be 97-percent elemental and 3-percent organic.

Release Pathways

When determining the offsite doses due to containment leakage, all of the RCS iodine, noble gas, and alkali metal activity (from prior to the accident and resulting from the accident) was assumed to be in the containment.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

When determining the doses due to the primary-to-secondary steam generator tube leakage, all of the RCS iodine, noble gas, and alkali metal activity (from before the accident and resulting from the accident) was assumed to be in the primary coolant.

Primary-to-secondary tube leakage and steaming from the steam generators continue until the RCS pressure drops below the secondary side pressure. Bounding times of 1 hour of leakage and 2 hours of steaming were selected for this analysis, although the analysis showed that leakage and releases would stop before these times.

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day. Although the primary-to-secondary pressure differential drops throughout the event, a constant leakage rate was assumed.

Removal Coefficients

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited byMCO. The bounding value for MCO is 0.10 percent. Therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

For the containment leakage pathway, no credit was taken for plateout onto containment surfaces or for containment spray operation that would remove airborne particulates and elemental iodine. Removal of iodine and alkali metal particulates in containment by the fan cooling unit (FCU) filters was credited, with a removal efficiency of 0.90 and a filtered flow of 8000 cfm for each of the three FCUs assumed to be in operation. No credit was taken for the charcoal filters on the FCUs.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached in approximately 71 seconds from event initiation. The SI signal causes the control room HVAC to switch from the normal-operation mode to the emergency operation mode. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 140 seconds after event initiation.

6.11.9.4.2 Acceptance Criteria

The offsite dose limit for a rod ejection is 6.3-rem TEDE, per RG 1.183 (Reference 5). This is ~25 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.4.3 Results and Conclusions

The calculated doses due to the rod ejection accident are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	4.4	6.3
LPZ	2.2	6.3
Control Room	0.9	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.5 SGTR Accident

The discussion of the thermal-hydraulic analysis for the SGTR event is given in Section 6.4 of this document.

6.11.9.5.1 Input Parameters and Assumptions

The major assumptions and parameters used in this analysis are itemized in Table 6.11-20.

The analysis of the SGTR radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5). The activity available for release to the environment included the iodine assumed to be initially present in the secondary coolant and the activity in the primary coolant (both iodine and noble gases) that could leak into the secondary coolant due to steam generator tube leakage.

The SGTR event was analyzed for two iodine spiking cases: one in which there is a pre-existing iodine spike resulting in elevated primary coolant activity, and the other in which an iodine spike is assumed to be initiated by the accident. For the pre-accident iodine spike case, it was assumed that a reactor transient occurs prior to the SGTR and raises the RCS iodine concentration to the *Technical Specification* limit for a transient of 60 µCi/gm of DE I-131. For the accident-initiated iodine-spike case, it was assumed that the reactor trip associated with the SGTR creates an iodine spike in the RCS, which increases the iodine release rate from the fuel to the RCS to a value 335 times greater than the release rate corresponding to a maximum equilibrium RCS concentration of 1.0 µCi/gm of DE I-131. The duration of the accident-initiated iodine spike is limited by the amount of activity available in the fuel-cladding gap. Based on having 8 percent of the iodine in the fuel-cladding gap, the gap inventory would be depleted within 4 hours, and the accident-initiated spike was terminated at that time.

The noble gas activity concentration in the RCS at the time the SGTR accident occurs was based on operation with a fuel defect level of 1 percent. The iodine activity concentration of the secondary coolant at that time was assumed to be equivalent to the *Technical Specification* limit of 0.10 µCi/gm of DE I-131.

Release Pathway

Break-flow flashing fractions and steam release rates from the intact and ruptured steam generator were calculated. The amount of break flow that flashes to steam was conservatively calculated assuming that all break flow is from the hot-leg side of the break and that the primary temperatures remain constant.

The break flow, flashed break flow, and steam release data presented in Table 6.4-2 of Section 6.4 of this document were used for the dose analysis.

The intact steam generator primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 432 gpd per steam generator for each of the intact steam generators.

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 was taken for steam released to the condenser.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

At 29 hours after the accident, the RHRS was assumed to be placed into service for heat removal and there was no further steam release to the atmosphere from the secondary system.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached at 6.53 minutes from event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 7.53 minutes after event initiation.

6.11.9.5.2 Acceptance Criteria

The offsite dose limit for a SGTR with a pre-accident iodine spike is 25-rem TEDE per RG 1.183 (Reference 5), which is also the guideline value of 10CFR50.67 (Reference 3). For an SGTR with an accident-initiated iodine spike, the offsite dose limit is 2.5-rem TEDE per RG 1.183 (Reference 5). This is 10 percent of the guideline value of 10CFR50.67. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.5.3 Results and Conclusions

The calculated doses due to the SGTR with a pre-existing iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	4.9	25
LPZ	1.9	25
Control Room	2.2	5

The calculated doses due to the SGTR with an accident-initiated iodine spike are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	1.9	2.5
LPZ	0.8	2.5
Control Room	0.9	5

The acceptance criteria are met.

The SB doses reported are for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.6 Small-Break LOCA

An abrupt failure of the primary coolant system was assumed to occur and it was assumed that the break would be small enough that the containment spray system would not be actuated by high containment pressure, but that the core would experience substantial cladding damage such that the fission product gap activity of all fuel rods would be released. Activity that is released to the containment is assumed to be released to the environment due to the containment leaking at its design rate. There is also a release path through the steam generators (primary-to-secondary leakage) until the primary system becomes depressurized to below the secondary system pressure.

6.11.9.6.1 Input Parameters and Assumptions

Separate calculations were performed to determine the doses resulting from the release of activity to containment and subsequent leakage to the environment and the doses resulting from the leakage of activity to the secondary system and subsequent release to the environment. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths.

A summary of input parameters and assumptions is provided in Table 6.11-21.

The analysis of the SBLOCA radiological consequences was performed using the analytical methods and assumptions credited in RG 1.183 (Reference 5).

Source Term

In determining the offsite doses following an SBLOCA, it was assumed that all of the fuel rods in the core suffer sufficient damage so that their gap activity was released and no fuel in the core melts. Five percent of the total core activity of iodines, noble gases, and alkali metals were assumed to be in the fuel-cladding gap.

It was assumed that for both the containment leakage release path and the primary-to-secondary leakage release path all iodine, noble gas, and alkali metal activity in the failed fuel gap was available for release.

Prior to the accident, it was assumed that the iodine activity concentration of the primary coolant was 60 μCi/gm of DE I-131. The noble gas and alkali metal activity concentrations in the RCS when the postulated accident occurs were based on operation with a fuel defect level of 1 percent.

Iodine Chemical Form

Iodine in containment was assumed to be 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. Iodine released from the secondary system was assumed to be 97-percent elemental and 3-percent organic.

Release Pathways

When determining the offsite doses due to containment leakage, all of the RCS iodine, noble gas, and alkali metal activity (from prior to the accident and resulting from the accident) was assumed to be in the containment.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

When determining the doses due to the primary-to-secondary steam generator tube leakage, all of the RCS iodine, noble gas, and alkali metal activity (from before the accident and resulting from the accident) was assumed to be in the primary coolant.

Primary-to-secondary tube leakage and steaming from the steam generators were assumed to continue until the RCS pressure drops below the secondary pressure. Bounding times of 1 hour of leakage and 2 hours of steaming were selected for this analysis, although the analysis shows that leakage and releases would stop before then.

The primary-to-secondary steam generator tube leakage rate was assumed to be at the *Technical Specification* limit of 1440 gallons per day. Although the primary-to-secondary pressure differential drops throughout the event, a constant leakage rate was assumed.

Removal Coefficients

An iodine partition factor in the steam generators of 0.01 (Ci iodine/gm steam)/(Ci iodine/gm water) was used. Prior to reactor trip and concurrent LOOP, an iodine removal factor of 0.01 could be taken for steam released to the condenser, but this was conservatively ignored.

The release of non-volatile activity from the steam generators is limited by the MCO. The bounding value for MCO is 0.10 percent. Therefore, an alkali metal partition factor in the steam generators of 0.001 (Ci alkali metal/gm steam)/(Ci alkali metal/gm water) was used.

All noble gas activity carried over to the secondary side through steam generator tube leakage was assumed to be immediately released to the outside atmosphere.

For the containment leakage pathway, no credit was taken for plateout onto containment surfaces or for containment spray operation that would remove airborne particulates and elemental iodine. Deposition removal of elemental iodine was not credited. Removal of iodine and alkali metal particulates in containment by the FCU filters was credited, with a removal efficiency of 0.90 and a filtered flow of 8000 cfm for each of the three FCUs assumed to be in operation. No credit was taken for the charcoal filters on the FCUs.

Control Room Isolation

The low-pressurizer pressure SI setpoint would be reached approximately 71 seconds after event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 140 seconds after event initiation.

6.11.9.6.2 Acceptance Criteria

The offsite dose limit for a LOCA is 25-rem TEDE, per RG 1.183 (Reference 5). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.6.3 Results and Conclusions

The calculated doses due to the SBLOCA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	11.0	25
LPZ	5.5	25
Control Room	2.2	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.7 Large-Break LOCA

In this analysis, an abrupt failure of a reactor coolant pipe was assumed to occur, and it was also assumed that the emergency core cooling features would fail to prevent the core from experiencing significant degradation (that is, melting). This sequence cannot occur unless there are multiple failures, and thus goes beyond the typical DBA that considers a single active failure. Activity from the core is released to the containment and then to the environment by containment leakage or leakage from the Emergency Core Cooling System (ECCS) as it recirculates sump solution outside the containment.

6.11.9.7.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-22.

The analysis of the LBLOCA radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5).

The analysis considered the release of activity from the damaged core to the containment via containment leakage. In addition, it was assumed that once external recirculation of the ECCS was established, activity in the sump solution would be released to the environment by means of leakage from ECCS equipment outside containment in the Auxiliary Building. The total offsite and control room doses are the sum of the doses resulting from each of the postulated release paths. The following sections address topics of significant interest in the analysis.

Source Term

The reactor coolant activity was assumed to be insignificant compared with the release from the core and was not included in the analysis.

Of the total core activity provided in Table 6.11-13, the following portions were assumed to be released to the containment atmosphere and available for release to the environment via containment leakage:

- 100 percent of the noble gases (Xe, Kr)
- 40 percent of the iodines
- 30 percent of the alkali metals (Cs, Rb)
- 5 percent of the tellurium metals (Te, Sb)
- 2 percent of the barium and strontium
- 0.25 percent of the noble metals (Ru, Rh, Mo, Tc)
- 0.05 percent of the cerium group (Ce, Pu, Np)
- 0.02 percent of the lanthanides (La, Zr, Nd, Nb, Pr, Y, Cm, Am)

The release of activity to containment is assumed to occur over a 1.8-hour interval. The gap activity is released in the first 30 minutes (starting at 30 seconds), and the fraction of the core activity that is released due to fuel melt does so over the next 1.3 hours. A gap fraction of 5 percent of core activity was assumed for iodines, noble gases, and alkali metals. Gap activity of the other nuclides is not assumed in the RG 1.183 (Reference 5) source term. With the exception of the iodines and noble gases, all activity released to containment was modeled as particulates. The iodine in containment was modeled as 4.85-percent elemental, 0.15-percent organic, and 95-percent particulate. For ECCS leakage considerations, the iodine activity that became airborne after being released by the leakage was modeled as 97-percent elemental and 3-percent organic.

For the containment leakage analysis, all activity released from the fuel was assumed to be in the containment atmosphere until removed by sprays, sedimentation, radioactive decay, or leakage from the containment. No credit was taken for removal of activity by the FCU filters. For the ECCS leakage analysis, all iodine activity released from the fuel was assumed to be in the sump solution until removed by radioactive decay or leakage from the ECCS.

Containment Modeling

The containment was modeled as two discrete volumes that considered hold-up, removal, and decay. The two volumes were the sprayed containment, which accounted for 80 percent of the free volume, and the unsprayed containment. Mixing between the two volumes was provided by the fan coolers. The analysis credited three fan coolers starting 60 seconds after event initiation.

The containment was assumed to leak at the design leak rate of 0.1 percent per day for the first 24 hours of the accident, and then to leak at half that rate (0.05 percent per day) for the remainder of the 30-day period considered in the analysis.

Activity Removal from the Containment Atmosphere

Only containment sprays and radioactive decay were credited for removal of elemental iodine from the containment atmosphere. Containment sprays, sedimentation, and radioactive decay were credited for removing particulates from the containment atmosphere. The noble gases and the organic iodine were subject to removal only by radioactive decay. No credit was taken for the HEPA and charcoal filters on the FCUs.

One train of the Containment Spray System (CSS) was assumed to operate following the LOCA. Injection spray was credited with a 67-second startup delay. Earlier spray actuation is conservative since it results in earlier spray injection phase termination. There would be little activity in the containment at the time the sprays start. When the refueling water storage tank (RWST) drains to a predetermined setpoint level, the operators switch to sump liquid recirculation to provide a source for the sprays. Injection spray was credited for approximately 44 minutes. There is a 3-minute period with no spray flow during the switchover to the spray recirculation phase. The analysis assumed that the recirculation sprays would operate until 4.0 hours into the accident. Retention of iodine in the sump solution is ensured by adjusting the sump solution to a pH greater than or equal to 7.0.

<u>Containment Spray Removal of Elemental Iodine</u>

The SRP 6.5.2 (Reference 29) identifies a methodology to determine spray removal of elemental iodine. The removal rate constant is determined by:

$$\lambda_s = 6K_g\ TF/VD$$

where:

λ_s = Elemental iodine removal rate constant due to spray removal, hr^{-1}
K_g = Gas phase mass transfer coefficient, ft/min
T = Time of fall of the spray drops, min
F = Volume flow rate of sprays, ft^3/hr
V = Containment sprayed volume, ft^3
D = Mass-mean diameter of the spray drops, ft

The upper limit specified for this model is 20 hr^{-1}.

The parameters listed below were chosen to bound the current plant configuration:

K_g = 9.84 ft/min
T = 10 sec
F = 2200 gpm
V = 2.088E6 ft^3
D = 0.112 cm

These parameters and appropriate conversion factors were used to calculate the elemental spray removal coefficients. The upper limit of 20 hr^{-1} specified for this model was applied in the analysis in place of the calculated value of 22.7 hr^{-1}.

The elemental iodine removal rate during recirculation spray operation can be calculated by multiplying the injection spray removal rate (22.7 hr^{-1}) by the ratio of the recirculation spray flow rate (1050 gpm) to the injection spray flow rate (2200 gpm). The recirculation spray removal rate is then 10.8 hr^{-1}. However, during recirculation, the spray solution would gradually become loaded with elemental iodine that will limit the capacity of the spray to remove airborne iodine. As the DF approaches its defined limit, the removal coefficient would be only a small fraction of its original value. This was approximated by setting the removal coefficient at approximately one half of the calculated value (5.0 hr^{-1}).

Removal of elemental iodine from the containment atmosphere was assumed to be terminated when the airborne inventory (including both sprayed and unsprayed regions) dropped to 0.5 percent of the total elemental iodine released to the containment (this is a DF of 200). With the RG 1.183 (Reference 5) source term methodology, this was interpreted as being 0.5 percent of the total inventory of elemental iodine that was released to the containment atmosphere over the duration of gap and in-vessel release phases. In the analysis, this occurred at 2.765 hours.

Containment Spray Removal of Particulates

Particulate spray removal was determined using the model described in the SRP 6.5.2 (Reference 29).

The first order spray removal rate constant for particulates is written as follows:

$$\lambda_p = 3hFE/2VD$$

where:

λ_p = Particulate removal rate constant due to spray removal, hr^{-1}
h = Drop fall height, ft
F = Spray flow rate, ft^3/hr
V = Volume sprayed, ft^3
E = Single drop collection efficiency
D = Average spray drop diameter, ft

The parameters listed below were chosen to bound the current plant configuration:

h = 118.5 ft
F = 2200 gpm
V = 2.088E6 ft^3

The E/D term depends upon the particle size distribution and spray drop size. It is conservative to use 10 m^{-1} for E/D until the point is reached when the inventory in the atmosphere is reduced to 2 percent of its original (DF of 50). With the RG 1.183 (Reference 5) source term methodology, this is interpreted as being 2 percent of the total inventory particulate iodine that is released to the containment atmosphere over the duration of gap and in-vessel release phases.

These parameters and the appropriate conversion factors were used to calculate the particulate spray removal coefficients. A value of 4.6 hr^{-1} was used in the analysis during the spray injection phase. The recirculation spray particulate removal rate used was 2.2 hr^{-1} corresponding with the reduction in the spray flow rate (2200-gpm injection reduced to 1050 gpm for recirculation). Recirculation sprays were assumed to be terminated at 4.0 hours. The DF of 50 was not reached by 4.0 hours, so no reduction in the spray removal coefficient for particulates was modeled.

Sedimentation Removal of Particulates

During spray operation, no credit was taken for sedimentation removal of particulates in the sprayed region, although it would take place. It was assumed that containment spray operation would be terminated at 4.0 hours. Credit was taken for sedimentation removal of particulates in the sprayed region after spray termination. Sedimentation was credited in the unsprayed region from the start of the event. The analysis assumed a sedimentation coefficient of 0.1 hr^{-1}.

Emergency Core Cooling System Leakage

Initially, the ECCS recirculation would be internal to the containment and there would be no potential for leakage outside containment. However, the switch to external recirculation was assumed to occur at 6.5 hours because of the need to switch from cold-leg recirculation mode to hot-leg recirculation mode. With external ECCS recirculation established following the LOCA, leakage was assumed to occur from ECCS equipment outside containment. The leakage goes into the Auxiliary Building and no filtration or holdup was credited for this release. The ECCS leakage was modeled as 4.0 gallons per hour which, consistent with RG 1.183 (Reference 5), is double the plant allowable leakage value of 2.0 gallons per hour. The leakage was assumed to continue for the 30-day period considered in the analysis. Based on the sump solution pH, the temperature of the leaked solution, and the ventilation provided in the Auxiliary Building, a bounding value for the iodine partition coefficient was determined to be 0.027.

Control Room Isolation

In the event of an LBLOCA, the low-pressurizer pressure SI setpoint will be reached shortly after event initiation. The SI signal causes the control room HVAC to switch from the normal operation mode to the emergency mode of operation. It was conservatively assumed that the control room HVAC would not fully enter the emergency mode of operation until 1 minute after event initiation.

6.11.9.7.2 Acceptance Criteria

The offsite dose limit for a LOCA is 25-rem TEDE per RG 1.183 (Reference 5). This is the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.7.3 Results and Conclusions

The calculated total offsite and control room doses due to the LBLOCA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	23.4	25
LPZ	11.2	25
Control Room	4.4	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0.6 to 2.6 hours.

Subsection 6.11.4.6 of this report discusses the calculation of the direct and skyshine control room dose. The calculated dose for the 30-day duration considered in this analysis was 0.284 mrem. This dose was included in the control room dose reported above.

6.11.9.8 GDT Rupture Radiological Consequences

For the GDT rupture analysis, there is assumed to be a failure that results in the release of the contents of one GDT.

6.11.9.8.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-23.

Consistent with the UFSAR analysis, the tank contents were assumed to be at the administratively controlled limit of 50,000 Curies of dose equivalent Xe-133. Dose equivalent Xe-133 is the amount of Xe-133 that results in the same gamma radiation dose as a given mixture of noble gases. A failure in the Gaseous Waste Processing System (GWPS) was assumed to result in release of a single tank inventory with a release duration of 5 minutes.

Control Room Isolation

It is assumed that the control room HVAC System is manually switched over from the normal-operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.8.2 Acceptance Criteria

The offsite dose limit for a GDT rupture is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.8.3 Results and Conclusions

The calculated doses due to the GDT rupture are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.32	0.5
LPZ	0.12	0.5
Control Room	0.1	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.9 VCT Rupture

For the VCT rupture, a failure was assumed that results in the release of the tank contents, plus the noble gases and a fraction of the iodines from the letdown flow until the letdown path is isolated.

6.11.9.9.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-24.

The inventory of gases in the tank was based on continuous operation with 1.0-percent fuel defects and without any purge of the gas space. The inventory of iodine in the tank was based on operation of the plant with 1.0 μCi/gram Dose-Equivalent (DE) I-131 in the primary coolant and with 90 percent of the iodine removed by the letdown demineralizer.

As a result of the accident, all of the noble gas in the tank and 1.0 percent of the iodine in the tank liquid were assumed to be released to the atmosphere over a period of 5 minutes.

After event initiation, letdown flow to the VCT was assumed to continue at the maximum flow rate of 132 gpm (maximum letdown flow plus 10-percent uncertainty) for 30 minutes when the letdown line was assumed to be isolated. The primary coolant noble gas activities were based on operation with 1-percent fuel defects. The primary coolant iodine activity was assumed to be at the equilibrium operation *Technical Specification* limit of 1.0 μCi/gram DE I-131, which was reduced by 90 percent by the letdown demineralizer. All of the noble gas and 10 percent of the iodine in the letdown flow were assumed to be released to the environment.

Control Room Isolation

It was assumed that the control room HVAC System is manually switched over from the normal operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.9.2 Acceptance Criteria

The offsite dose limit for a VCT rupture is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.9.3 Results and Conclusions

The calculated doses due to the VCT rupture are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.42	0.5
LPZ	0.16	0.5
Control Room	0.08	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.10 Holdup Tank Failure

During normal plant operation water is added to the HTs periodically as the primary coolant is diluted during the fuel cycle to provide reduction in the primary coolant boron concentration. As water enters the HT, gases (the nitrogen cover gas and the noble gas and hydrogen that evolve out of solution from the water entering the tank) are displaced to the GWPS. For the HT failure, a failure is assumed that results in the release of the contents of the tank.

6.11.9.10.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-25.

The inventory of gases in the tank was based on letdown of primary coolant to fill the HT in a 24-hour period without any purge of the tank gas space. The primary coolant noble gas concentration was based on operation with 1.0 percent fuel defects and without any fission gas removal other than by decay. The inventory of iodine in the tank was based on operation with a primary coolant concentration at the equilibrium concentration *Technical Specification* limit of 1.0 μCi/gram of DE I-131 and with 90 percent of the iodine removed by the letdown demineralizer.

As a result of the HT failure, all of the noble gas in the tank and 1.0 percent of the iodine in the tank liquid were assumed to be released to the atmosphere over a period of 5 minutes.

<u>Control Room Isolation</u>

It was assumed that the control room HVAC System is manually switched over from the normal-operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.10.2 Acceptance Criteria

The offsite dose limit for an HT failure is 0.5-rem TEDE. This is consistent with the guidance of RG 1.26 (Reference 12), which specifies 0.5-rem whole body or equivalent to any part of the body and of RG 1.183 (Reference 5), which specifies that doses will be determined as TEDE. The limit for the control room dose is 5-rem TEDE, per 10CFR50.67 (Reference 3).

6.11.9.10.3 Results and Conclusions

The calculated doses due to the HT failure are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	0.38	0.5
LPZ	0.14	0.5
Control Room	0.10	5

The acceptance criteria are met.

The SB dose reported is for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.9.11 Fuel-Handling Accident

This accident assumes that a fuel assembly is dropped and damaged during refueling. Analysis of the accident was performed with assumptions selected so that the results would be bounding for the accident occurring either inside containment or in the Fuel Handling Building. Activity released from the damaged assembly was assumed to be released to the outside atmosphere through either the Containment Purge System or the Fuel Pit Ventilation System.

6.11.9.11.1 Input Parameters and Assumptions

The input parameters and assumptions are listed in Table 6.11-26.

The analysis of the FHA radiological consequences was performed using the analytical methods and assumptions outlined in RG 1.183 (Reference 5). This analysis allowed fuel movement 84 hours after shutdown.

All activity released from the water pool was assumed to be released to the atmosphere in 2 hours, using a linear release model (this is the release model used in the existing licensing basis for this event). No credit was taken for operating the Spent Fuel Pit Ventilation System in the Fuel-Handling Building. No credit was taken for isolating containment for the FHA in containment. Since the assumptions and parameters for an FHA inside containment are identical to those for a FHA in the Fuel-Handling Building, the radiological consequences were the same regardless of the location of the accident.

Source Term

The calculation of the radiological consequences following an FHA used gap fractions of 12 percent for I-131, 30 percent for Kr-85, and 10 percent for all other nuclides. The value for I-131 was taken from NUREG/CR-5009 (Reference 30). The values for Kr-85 and the other iodines and noble gases were taken from RG 1.25 (Reference 31). There are lower values identified in Table 3 of RG 1.183 (Reference 5), but these were not used because the conditions for their use (specified in footnote 11 in RG 1.183) have not been ensured.

As in the existing licensing basis, it was assumed that all of the fuel rods in the equivalent of one fuel assembly would be damaged to the extent that all of their gap activity would be released. The assembly inventory was based on the assumption that the subject fuel assembly had been operated at 1.7 times the core average power. The activity calculated for the third transition cycle was conservatively increased by 4 percent to bound variations in core average enrichment, core mass, and cycle length (Table 6.11-27).

The decay time used in the analysis was 84 hours.

Iodine Chemical Form

The iodine released from the fuel was assumed to be 95-percent cesium iodide (CsI), 4.85-percent elemental iodine, and 0.15-percent organic iodine. It was assumed that all of the CsI was dissociated in the water and that the iodine re-evolved as elemental iodine. This was assumed to occur instantaneously. Thus, the FHA dose analysis was based on an initial iodine characterization of 99.85-percent elemental iodine and 0.15-percent organic iodine.

Water Scrubbing Removal of Activity

The activity released from the damaged fuel rods was assumed to be contained within gas bubbles that rise up through the water and are released into the atmosphere above the pit. As the bubbles pass through the water column, there is a significant removal of activity. RG 1.183 (Reference 5) identifies a DF of 500 for elemental iodine and no removal for organic iodine and noble gases. The DF of 500 for elemental iodine is based on having a water height of 23 feet or more. (Per the *Technical Specifications*, there are requirements for ≥23 feet of water above the stored spent fuel and above the reactor vessel flange during fuel-handling operations.)

The DF of 500 for elemental iodine is also based on fuel rod pressure of ≤1200 psig. There is the potential for fuel rod pressures to exceed 1200 psig (but remain less than 1500 psig). With this increase in fuel rod pressure, the DF is determined to remain above 400. Using a DF of 400 for elemental iodine and the defined iodine species split of 99.85-percent elemental

and 0.15-percent organic, the overall DF would be 250. However, RG 1.183 (Reference 5) also specifies the overall DF for iodine to be 200. The overall DF of 200 has an associated elemental iodine DF of 285, and this value was used in the analysis together with a DF of 1.0 for organic iodine and noble gases.

The cesium released from the damaged fuel rods was assumed to remain in a nonvolatile form and not be released from the water.

The split between elemental and organic iodine being released to the environment had no effect on the analysis since no filtration was credited.

Filtration of Release Paths

No credit was taken for removing iodine by filters, nor was credit taken for isolating release paths.

Although the containment purge would be automatically isolated on a purge line high-radiation alarm, isolation was not modeled in the analysis. The activity released from the damaged assembly was assumed to be released to the outside atmosphere over a 2-hour period. Since no filtration or containment isolation was modeled, this analysis supports refueling operation with the equipment hatch and the personnel air lock remaining open.

Control Room Isolation

It was assumed that the control room HVAC System is manually switched over from the normal operation mode to the emergency mode of operation after a high radiation alarm is actuated.

6.11.9.11.2 Acceptance Criteria

The offsite dose limit for an FHA is 6.3-rem TEDE per RG 1.183 (Reference 5). This is ~25 percent of the guideline value of 10CFR50.67 (Reference 3). The limit for the control room dose is 5-rem TEDE, per 10CFR50.67.

6.11.9.11.3 Results and Conclusions

The calculated doses due to the FHA are:

Case	TEDE Dose (rem)	Acceptance Criteria (rem TEDE)
SB	5.7	6.3
LPZ	2.1	6.3
Control Room	1.4	5

The acceptance criteria are met.

The SB dose reported was for the worst 2-hour period, determined to be from 0 to 2 hours.

6.11.10 References

1. NRC Regulatory Guide 1.49, *Power Levels of Nuclear Power Plants*, Rev. 1, May 1973.

2. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment RE: 1.4-Percent Power Uprate (TAC NO. MB5297),* License Amendment No. 213, Docket No. 50-286, November 26, 2002.

3. 10CFR50.67, *Accident Source Term*, 64 FR 72001, December 23, 1999.

4. NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants,* 15.0.1, "Radiological Consequence Analyses using Alternative Source Terms," Rev. 0.

5. NRC Regulatory Guide 1.183, *Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,* Rev. 0, July 2000.

6. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment Affecting Adoption of Alternate Source Term for the Fuel Handling Accident (TAC NO. MB5382),* Amendment No. 215, Docket No. 50-286, March 17, 2003.

7. Letter from F. Dacimo (Entergy Nuclear Operations, Inc.) to P. Milano (NRC), *Indian Point Nuclear Generating Unit No. 3 – RE: Application of Alternate Source Term for the Radiological Dose Analyses for IP3* Docket No. 50-286, June 2, 2004.

8. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

9. 10CFR50, Appendix I, *Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion As Low As Reasonably Achievable for Radioactive Material in Light Water Cooled Nuclear Power Reactor Effluents*, July 29, 1996.

10. Appendix A to Facility Operating License DPR-64 for Entergy Nuclear Indian Point 3, LLC and Entergy Nuclear Operations, Inc., *Indian Point Nuclear Generating Plant Unit No. 3, Docket No. 50-286, Technical Specifications and Bases.*

11. *IP3 Offsite Dose Calculation Manual.*

12. NRC Regulatory Guide 1.26, *Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants*, Rev. 2, June 1975.

13. TID-14844, *Calculation of Distance Factors for Power and Test Reactor Sites*, 1962.

14. SECY-98-154, *Results of the Revised (NUREG-1465) Source Term Rebaselining for Operating Reactors*, June 30, 1998.

15. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

16. RSIC Computer Code Collection CCC-371, *ORIGEN2.1: Isotope Generation and Depletion Code – Matrix Exponential Method*, February 1996.

17. ANSI/ANS-18.1-1999, *Radioactive Source Term for Normal Operation of Light Water Reactors*, The American Nuclear Society Standards Institute, Inc., LaGrange Park, Illinois, September 21, 1999.

18. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

19. NUREG-0017, *Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors*, Rev. 1, April 1985.

20. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

21. UE&C Report, *Design Review of Plant Shielding and Environmental Qualification of Equipment for Spaces/Systems which May Be Used in Post Accident Conditions*, July 1981.

22. *NRC Plant Shielding Design Review Inspection Report 50-286/83-05*, May 12, 1983.

23. NUREG-0737, Item 11.B.2.2, *Design Review of Plant shielding – Corrective Actions for Access to Vital Areas, Power Authority of the State of New York, Indian Point Generating Station Unit No. 3*, February 28, 1984.

24. UE&C Report, *Design Review of the Plant Accessibility Environmental Qualification of Equipment for Area/Systems Requiring Occupancy and/or use during Post Delta Pressurized Design Basis Accident Recovery Operations*, August 1985.

25. Letter from P. Milano (NRC) to M. Kansler (Entergy Nuclear Operations, Inc.), *Indian Point Nuclear Generating Unit No. 3 – RE: Issuance of Amendment to Delete Requirements for Post Accident Sampling*, Amendment No. 210, Docket No. 50-286, February 6, 2002.

26. 10CFR50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, 66FR64738, December 14, 2001.

27. EPA Federal Guidance Report No. 11, EPA-520/1-88-020, *Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion*, September 1988.

28. EPA Federal Guidance Report No. 12, EPA 402-R-93-081, *External Exposure to Radionuclides in Air, Water and Soil*, September 1993.

29. NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants*, 6.5.2, "Containment Spray as a Fission Product Cleanup System," Rev. 2, December 1988.

30. NUREG/CR-5009, *Assessment of the Use of Extended Burnup Fuel in Light Water Reactors*, February 1988.

31. NRC Regulatory Guide 1.25, *Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors*, March 1972.

Table 6.11-1 Input Parameters for Core Inventory Calculations - Cycle 16	
Parameter	**Value**
Core Thermal Power (MWt)	3280.3 (3216*1.02)
Fuel Assembly Type	15 x 15
Uranium Mass (MTU)	86.6
Cycle Length (MWD/MTU)	25,432
Loading Pattern	See Table 6.11-2
Uranium Enrichments (wt % U-235)	Region 16A 4.48 Region 17B 4.80 Region 18B 4.80

Table 6.11-2 Input Parameters for Loading Pattern - Cycle 16			
Region	**No. of Assemblies**	**EOC Burnup (MWD/MTU)**	**Average Relative Power**
Feed Region 18B	93	30,830	1.21
1 x Burned Region 17B	92	51,920	0.85
2 x Burned Region 16A	8	45,990	0.20

Table 6.11-3

Core Inventory with 1.04 Fuel Management Variation Multiplier (core power = 3280.3 MWt)

Nuclide	Inventory at Shutdown (Ci)	Inventory at 84 Hours after Shutdown (Ci)	Nuclide	Inventory at Shutdown (Ci)	Inventory at 84 Hours after Shutdown (Ci)
Noble Gases			Other Isotopes		
KR 85	1.11E+06	1.11E+06	SR 89	8.84E+07	8.43E+07
KR 85M	2.44E+07	5.62E+01	SR 90	8.79E+06	8.79E+06
KR 87	4.69E+07	0.00E+00	SR 91	1.11E+08	2.43E+05
KR 88	6.60E+07	0.00E+00	SR 92	1.20E+08	0.00E+00
XE131M	9.92E+05	9.71E+05	Y 90	9.16E+06	8.94E+06
XE133	1.79E+08	1.36E+08	Y 91	1.14E+08	1.10E+08
XE133M	5.45E+06	2.78E+06	Y 92	1.21E+08	3.66E+01
XE135	4.77E+07	7.86E+05	Y 93	1.39E+08	4.43E+05
XE135M	3.68E+07	4.21E+03	NB 95	1.56E+08	1.55E+08
XE138	1.55E+08	0.00E+00	ZR 95	1.54E+08	1.49E+08
Halogens			ZR 97	1.55E+08	4.94E+06
I130	3.78E+06	3.41E+04	MO 99	1.75E+08	7.23E+07
I131	9.10E+07	6.90E+07	TC 99M	1.53E+08	6.97E+07
I132	1.33E+08	6.38E+07	RU103	1.39E+08	1.31E+08
I133	1.88E+08	1.17E+07	RU105	9.58E+07	1.99E+02
I134	2.06E+08	0.00E+00	RU106	4.84E+07	4.81E+07
I135	1.76E+08	2.63E+04	RH105	8.83E+07	1.98E+07
Rb and Cs			SB127	9.89E+06	5.34E+06
RB 86	2.36E+05	2.07E+05	SB129	2.97E+07	4.21E+01
CS134	2.05E+07	2.04E+07	TE127	9.83E+06	6.36E+06
CS136	5.96E+06	4.95E+06	TE127M	1.28E+06	1.27E+06
CS137	1.19E+07	1.19E+07	TE129	2.92E+07	2.60E+06
CS138	1.72E+08	0.00E+00	TE129M	4.28E+06	4.00E+06
CS138M	8.09E+06	0.00E+00	TE131M	1.33E+07	1.93E+06
Actinides			TE132	1.30E+08	6.20E+07
PU238	4.11E+05	4.14E+05	BA139	1.68E+08	0.00E+00
PU239	3.50E+04	3.53E+04	BA140	1.60E+08	1.32E+08
PU240	5.21E+04	5.21E+04	LA140	1.65E+08	1.48E+08
PU241	1.17E+07	1.17E+07	LA141	1.53E+08	6.13E+01
NP239	1.87E+09	6.71E+08	LA142	1.48E+08	0.00E+00
AM241	1.44E+04	1.46E+04	CE141	1.52E+08	1.42E+08
CM242	3.47E+06	3.44E+06	CE143	1.43E+08	2.46E+07
CM244	3.70E+05	3.70E+05	CE144	1.20E+08	1.19E+08
			PR143	1.37E+08	1.25E+08
			ND147	6.07E+07	4.88E+07

Note:

1. Curie values less than 1.0 are not significant and are assigned a value of zero.

Table 6.11-4 Input Parameters for RCS Activity and VCT Inventory Calculations	
Parameter	**Value**
Core Thermal Power (MWt)	3280.3 (3216*1.02) 3216 for tritium
Cycle Length (full-power days)	685
Maximum Boron Concentration (ppm)	1238
Mixed-Bed Demineralizer Resin Volume (ft^3)	30
Failed Fuel Fraction (%)	1.0
Reactor Coolant Mass (lbm)	4.82×10^5
Purification System Flow Rate, Normal (gpm)	45
Purification System Flow Rate, Maximum (gpm)	132
VCT Liquid Volume (ft^3)	134
VCT Vapor Volume (ft^3)	266
VCT Temperature (°F)	130
Tritium Release Fraction from Fuel Rods Design Basis Expected	 0.1 0.02
RCS Lithium Concentration (ppm)	3

Table 6.11-5

Reactor-Coolant-Fission and Corrosion-Product-Specific Activities (core power = 3280.3 MWt)

Nuclide	Activity uCi/g	Nuclide	Activity uCi/g	Nuclide	Activity uCi/g
Kr-83m	5.04E-01	Mn-54	1.60E-03	Ag-110m	8.70E-03
Kr-85m	2.03E+00	H-3	3.5 (max)	Te-125m	2.01E-03
Kr-85	1.37E+01	Cr-51	5.50E-03	Te-127m	6.48E-03
Kr-87	1.30E+00	Mn-56	2.00E-02	Te-127	2.16E-02
Kr-88	3.81E+00	Fe-55	2.00E-03	Te-129m	1.96E-02
Kr-89	1.03E-01	Fe-59	5.20E-04	Te-129	2.08E-02
Xe-131m	3.23E+00	Co-58	1.56E-02	Te-131m	3.80E-02
Xe-133m	3.52E+00	Co-60	1.98E-03	Te-131	1.67E-02
Xe-133	2.46E+02	Rb-86	6.92E-02	Te-132	4.68E-01
Xe-135m	6.25E-01	Rb-88	4.48E+00	Te-134	3.28E-02
Xe-135	9.56E+00	Rb-89	2.06E-01	Ba-137m	4.19E+00
Xe-137	1.97E-01	Sr-89	7.43E-03	Ba-140	7.14E-03
Xe-138	7.14E-01	Sr-90	4.90E-04	La-140	2.95E-03
Br-83	1.10E-01	Sr-91	7.34E-03	Ce-141	1.10E-03
Br-84	5.10E-02	Sr-92	1.43E-03	Ce-143	7.48E-04
Br-85	5.86E-03	Y-90	1.68E-04	Pr-143	1.07E-03
I-127 (a)	2.62E-10	Y-91m	4.09E-03	Ce-144	4.92E-04
I-129	1.45E-07	Y-91	9.91E-04	Pr-144	4.92E-04
I-130	9.60E-02	Y-92	1.36E-03		
I-131	4.67E+00	Y-93	4.87E-04		
I-132	3.18E+00	Zr-95	1.09E-03		
I-133	6.28E+00	Nb-95	1.09E-03		
I-134	6.82E-01	Mo-99	1.23E+00		
I-135	3.05E+00	Tc-99m	1.15E+00		
Cs-134	8.82E+00	Ru-103	1.09E-03		
Cs-136	5.46E+00	Rh-103m	1.08E-03		
Cs-137	4.43E+00	Ru-106	5.71E-04		
Cs-138	1.08E+00	Rh-106	5.71E-04		

Notes:

1. (a) Grams of I-127 per gram of coolant.
2. Mn-54 is from the ANSI/ANS-18.1-1999.
3. Calculated specific activities have been multiplied by 1.04.
4. Operation with defects in fuel which generates 1% of core power.
5. RCS purification of 45 gpm at 130F and 40.0 psia.
6. No VCT purging.
7. RCS mass – 2.19E+08 g.

Table 6.11-6 Nuclide Inventories for Noble Gases and Iodine in the VCT (total of gas and liquid phases)	
VCT Isotope	Inventory (curies)
Kr-83m	2.93E+01
Kr-85m	1.61E+02
Kr-85	2.24E+02
Kr-87	4.96E+01
Kr-88	2.40E+02
Kr-89	2.33E-01
Xe-131m	3.95E+02
Xe-133m	4.18E+02
Xe-133	3.04E+04
Xe-135m	7.54E+01
Xe-135	9.57E+02
Xe-137	5.36E-01
Xe-138	6.68E+00
I-127[1]	3.34E-11
I-129	1.85E-08
I-130	1.97E-02
I-131	6.29E-01
I-132	9.61E-01
I-133	1.14E+00
I-134	2.33E-01
I-135	7.38E-01

Note:

1. g I-127/g water

Table 6.11-7

Reactor Coolant Tritium Activity
(curies per cycle)

Tritium Source	Total Produced (curies)	Released to the Coolant	
		Design Value (curies)	Expected Value (curies)
Ternary Fissions	22280	2228	446
Soluble Poison Boron	1013	1013	1013
Burnable Poisons	4245	425	85
Li-7 Reaction	37	37	37
Li-6 Reaction	286	286	286
Deuterium Reaction	5	5	5
Total - Equilibrium Cycle	27866	3994	1872

Table 6.11-8 ANSI/ANS 18.1 – 1999 Normal Source Input Parameters			
Parameter	**Symbol**	**Value**	**Units**
Core Thermal Power	P	3.216E+03	MWt
Weight of Water in RCS	WP	8.06E+04	gal
Reactor Coolant Letdown Flow Rate (purification)	FD	7.50E+01	gpm
Reactor Coolant Letdown Flow Rate (yearly average for boron control)	FB	1.52E-01	gpm
Flow through the Purification System Cation Demineralizer	FA	7.50E+00	gpm
Steam Flowrate	FS	1.32E+07	lb/hr
Weight of Secondary Side Water in all Steam Generators	WS	3.40E+05	lb
Steam Generator Blowdown Flowrate (total)	FBD	1.20E+02	gpm
Parameters Used to Calculate the Y Parameter:			
Density of RCS Water	Drcs	4.51E+01	lb/ft^3
VCT Liquid Volume	VOL-L	1.30E+02	ft^3
VCT Vapor Space Volume	VOL-V	2.70E+02	ft^3
VCT Purge Rate	PR	0.00E+00	scfm
Density of VCT Water	Dvct	6.17E+01	lb/ft^3
VCT Temperature	TEMP	1.27E+02	°F
VCT Vapor Pressure	PRESS	2.97E+01	psig

Note:
Values for NB, NA, NBD, NC, NS, and NX are equal to ANSI/ANS 18.1 values.

Table 6.11-9 Estimated Effect of Core SPU on Appendix I Doses				
Type of Dose	Appendix I Design Objectives	5 Yr Annual Average Doses (Base Case)*	Scaled Doses (SPU Case)**	Percentage of Appendix I Design Objectives for SPU Case
Liquid Effluents				
Dose to Total Body from all Pathways	3 mrem/yr	1.10E-3 mrem/yr	1.22E-3 mrem/yr	0.041%
Dose to any Organ from all Pathways	10 mrem/yr	2.70E-3 mrem/yr	3.00E-3 mrem/yr	0.03%
Gaseous Effluents				
Gamma Dose in Air	10 mrad/yr	3.34E-04 mrad/yr	3.74E-04 mrad/yr	0.0037%
Beta Dose in Air	20 mrad/yr	6.78E-04 mrad/yr	7.60E-04 mrad/yr	0.0038%
Dose to Total Body of an Individual	5 mrem/yr	Not reported in annual radioactive release report	12.1% increase	As other doses are a small fraction of Appendix I Limits, it is assumed that this dose and consequent increase is also a small fraction of Appendix I.
Dose to Skin of an Individual	15 mrem/yr	Not reported in annual radioactive release report	12.1% increase	As other doses are a small fraction of Appendix I Limits, it is assumed that this dose and consequent increase is also a small fraction of Appendix I.
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	15 mrem/yr	7.32E-04 mrem/yr	8.22E-04 mrem/yr	0.0055%

Notes:

- * Average core power level for the 5-year operation (base case) is 2956.15 MWt.
- ** Core power level assumed for SPU analysis is 3280.3 MWt.

Table 6.11-10 Nuclide Parameters			
Nuclide	Decay Constant (hr^{-1})	CEDE DCF (rem/Ci inhaled)	EDE DCF (rem· m^3 /Ci · sec)
I-130	5.61E-02	2.64E3	3.848E-01
I-131	3.59E-03	3.29E4	6.734E-02
I-132	3.01E-01	3.81E2	4.144E-01
I-133	3.33E-02	5.85E3	1.088E-01
I-134	7.91E-01	1.31E2	4.810E-01
I-135	1.05E-01	1.23E3	2.953E-01
Kr-85m	1.55E-01	NA	2.768E-02
Kr-85	7.38E-06	NA	4.403E-04
Kr-87	5.45E-01	NA	1.524E-01
Kr-88	2.44E-01	NA	3.774E-01
Xe-131m	2.43E-03	NA	1.439E-03
Xe-133m	1.32E-02	NA	5.069E-03
Xe-133	5.51E-03	NA	5.772E-03
Xe-135m	2.72E+00	NA	7.548E-02
Xe-135	7.63E-02	NA	4.403E-02
Xe-138	2.93E+00	NA	2.135E-01
Cs-134	3.84E-05	4.63E4	2.801E-01
Cs-136	2.20E-03	7.33E3	3.922E-01
Cs-137	2.64E-06	3.19E4	1.066E-01*
Cs-138	1.29E+00	1.01E2	4.477E-01
Rb-86	1.55E-03	6.62E3	1.780E-02
Te-127m	2.65E-04	2.15E4	5.439E-04
Te-127	7.41E-02	3.18E2	8.954E-04
Te-129m	8.60E-04	2.39E4	5.735E-03
Te-129	5.98E-01	8.95E1	1.018E-02
Te-131m	2.31E-02	6.40E3	2.594E-01
Te-132	8.86E-03	9.44E3	3.811E-02
Sb-127	7.50E-03	6.03E3	1.232E-01
Sb-129	1.60E-01	6.44E2	2.642E-01
Sr-89	5.72E-04	4.14E4	2.860E-04
Sr-90	2.72E-06	1.30E6	2.786E-05
Sr-91	7.30E-02	1.66E3	1.277E-01
Sr-92	2.56E-01	8.07E2	2.512E-01
Ba-139	5.03E-01	1.72E2	8.029E-03
Ba-140	2.27E-03	3.74E3	3.175E-02

Table 6.11-10 (Cont.)

Nuclide Parameters

Nuclide	Decay Constant (hr^{-1})	CEDE DCF (rem/Ci inhaled)	EDE DCF (rem· m^3 /Ci · sec)
Ru-103	7.35E-04	8.95E3	8.325E-02
Ru-105	1.56E-01	4.55E2	1.410E-01
Ru-106	7.84E-05	4.77E5	0.00E+00
Rh-105	1.96E-02	9.55E2	1.376E-02
Mo-99	1.05E-02	3.96E3	2.694E-02
Tc-99m	1.15E-01	3.26E1	2.179E-02
Ce-141	8.89E-04	8.95E3	1.269E-02
Ce-143	2.10E-02	3.39E3	4.773E-02
Ce-144	1.02E-04	3.74E5	3.156E-03
Pu-238	9.02E-07	3.92E8	1.806E-05
Pu-239	3.29E-09	4.29E8	1.569E-05
Pu-240	1.21E-08	4.29E8	1.758E-05
Pu-241	5.50E-06	8.25E6	2.683E-07
Np-239	1.23E-02	2.51E3	2.845E-02
Y-90	1.08E-02	8.44E3	7.030E-04
Y-91	4.94E-04	4.88E4	9.620E-04
Y-92	1.96E-01	7.81E2	4.810E-02
Y-93	6.86E-02	2.15E3	1.776E-02
Nb-95	8.22E-04	5.81E3	1.384E-01
Zr-95	4.51E-04	2.36E4	1.332E-01
Zr-97	4.10E-02	4.33E3	3.337E-02
La-140	1.72E-02	4.85E3	4.329E-01
La-141	1.76E-01	5.81E2	8.843E-03
La-142	4.50E-01	2.53E2	5.328E-01
Nd-147	2.63E-03	6.84E3	2.290E-02
Pr-143	2.13E-03	8.10E3	7.770E-05
Am-241	1.83E-07	4.44E8	3.027E-03
Cm-242	1.77E-04	1.73E7	2.105E-05
Cm-244	4.37E-06	2.48E8	1.817E-05

Notes:

CEDE = Committed effective dose equivalent
EDE = Effective dose equivalent
DCF = Dose conversion factor
* This is the DCF for Ba-137m. The DCF for Cs-137 is low; however a significant amount of Ba-137m is produced through decay. This is conservatively addressed by applying the DCF from Ba-137m to Cs-137.

Table 6.11-11 Offsite Breathing Rates and Atmospheric Dispersion Factors	
Time	**Offsite Breathing Rates (m^3/sec)**
0 - 8 hours	3.5E-4
8 - 24 hours	1.8E-4
>24 hours	2.3E-4
	Offsite Atmospheric Dispersion Factors (sec/m^3)
SB(1)	1.03E-3
LPZ	
0 - 2 hours	3.8E-4
2 - 24 hours	1.9E-4
> 1 day	1.7E-5

Note:

1. This SB atmospheric dispersion factor is conservatively applied during all time intervals in the determination of the limiting 2-hour period.

Table 6.11-12 Control Room Parameters		
Breathing Rate - Duration of the Event	3.5E-4 m^3/sec	
Control Room Volume	47,200 ft^3	
Occupancy Factors		
0 - 24 hours	1.0	
1 - 4 days	0.6	
4 - 30 days	0.4	
Normal Ventilation Flow Rates		
Filtered Makeup Flow Rate	0.0 scfm	
Filtered Recirculation Flow Rate	0.0 scfm	
Unfiltered Makeup Flow Rate	≤1500 scfm	
Unfiltered In-Leakage	≤700 scfm	
Emergency Ventilation System Flow Rates[1]	Option 1	Option 2
Filtered Makeup Air Flow Rate	≥400 scfm	≥1500 scfm
Filtered Recirculation Flow Rate	≥1000 scfm	0 scfm
Unfiltered Makeup Flow Rate	0 scfm	0 scfm
Unfiltered In-leakage	≤700 scfm	≤700 scfm
Filter Efficiencies		
Elemental Iodine	90%	
Organic Iodine	90%	
Particulates	99%	
Radiation Monitor Setpoint	1.0 mrem/hr	
Delay to Initiate Switchover of HVAC from Normal Operation to Emergency Operation after SI Signal	60 seconds	
Delay for Switchover of HVAC from Normal Operation to Emergency Operation after Receiving a High Alarm Signal (radiation monitor) Based on Manual Action	20 minutes	
Control Room Shielding	2 feet concrete	

Note:

1. The analyses are performed addressing each of the two options for control room HVAC operation in the emergency mode. The doses reported bound the two alternatives.

Table 6.11-13

Core Total Fission Product Activities Based on 3280.3 MWt (102% of 3216 MWt)

Isotope	Activity (Ci)
I-130	3.78E+06
I-131	9.10E+07
I-132	1.33E+08
I-133	1.88E+08
I-134	2.06E+08
I-135	1.76E+08
Kr-85m	2.44E+07
Kr-85	1.11E+06
Kr-87	4.69E+07
Kr-88	6.60E+07
Xe-131m	9.92E+05
Xe-133m	5.45E+06
Xe-133	1.79E+08
Xe-135m	3.68E+07
Xe-135	4.77E+07
Xe-138	1.55E+08
Cs-134	2.05E+07
Cs-136	5.96E+06
Cs-137	1.19E+07
Cs-138	1.72E+08
Rb-86	2.36E+05
Te-127m	1.28E+06
Te-127	9.83E+06
Te-129m	4.28E+06
Te-129	2.92E+07
Te-131m	1.33E+07
Te-132	1.30E+08
Sb-127	9.89E+06
Sb-129	2.97E+07

Table 6.11-13 (Cont.) Core Total Fission Product Activities Based on 3280.3 MWt (102% of 3216 MWt)	
Isotope	**Activity (Ci)**
Sr-89	8.84E+07
Sr-90	8.79E+06
Sr-91	1.11E+08
Sr-92	1.20E+08
Ba-139	1.68E+08
Ba-140	1.60E+08
Ru-103	1.39E+08
Ru-105	9.58E+07
Ru-106	4.84E+07
Rh-105	8.83E+07
Mo-99	1.75E+08
Tc-99m	1.53E+08
Ce-141	1.52E+08
Ce-143	1.43E+08
Ce-144	1.20E+08
Pu-238	4.11E+05
Pu-239	3.50E+04
Pu-240	5.21E+04
Pu-241	1.17E+07
Np-239	1.87E+09
Y-90	9.16E+06
Y-91	1.14E+08
Y-92	1.21E+08
Y-93	1.39E+08
Nb-95	1.56E+08
Zr-95	1.54E+08
Zr-97	1.55E+08
La-140	1.65E+08
La-141	1.53E+08
La-142	1.48E+08
Nd-147	6.07E+07
Pr-143	1.37E+08
Am-241	1.44E+04
Cm-242	3.47E+06
Cm-244	3.70E+05

Table 6.11-14

RCS Coolant Concentrations
Based on 1% Fuel Defects[1]

Nuclide	Activity (μCi/gm)
I-130	0.096
I-131	4.67
I-132	3.18
I-133	6.28
I-134	0.682
I-135	3.05
Kr-85m	2.03
Kr-85	13.7
Kr-87	1.30
Kr-88	3.81
Xe-131m	3.23
Xe-133m	3.52
Xe-133	246
Xe-135m	0.625
Xe-135	9.56
Xe-138	0.714
Cs-134	8.82
Cs-136	5.46
Cs-137	4.43
Cs-138	1.08
Rb-86	0.0692

Note:

1. Plant *Technical Specification* limits primary coolant iodine coolant concentration to 1.0 μCi/gm dose equivalent I-131. These coolant concentrations are provided in Table 6.11-15.

Table 6.11-15 Iodine Specific Activities (μCi/gm)			
Nuclide	Primary Coolant 1 μCi/gm(1)	Primary Coolant 60 μCi/gm	Secondary Coolant 0.10 μCi/gm
I-130	0.0161	0.97	0.0016
I-131	0.7849	47.09	0.0785
I-132	0.5345	32.07	0.0535
I-133	1.0555	63.33	0.1056
I-134	0.1146	6.88	0.0115
I-135	0.5126	30.76	0.0513

Note:

1. Iodine concentrations are converted to DE I-131 using the CEDE DCFs in Table 6.11-10.

Table 6.11-16 Iodine Spike Appearance Rates (Curies/Minute)(1)						
	I-130	I-131	I-132	I-133	I-134	I-135
335 Times the Equilibrium Rate (SGTR)	4.2	146.1	314.6	239.0	143.6	165.8
500 Times the Equilibrium Rate (MSLB)	6.2	218.0	469.6	356.7	214.3	247.5

Note:

1. Calculated based on the RCS concentration of 1.0 μCi/gm DE I-131, letdown flow of 120 gpm + 10% with perfect cleanup and RCS leakage of 11 gpm.

Table 6.11-17	
Assumptions Used for Steamline Break Dose Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Primary Coolant Noble Gas Activity prior to Accident	Based on operation with 1.0% Fuel Defects (See Table 6.11-14)
Primary Coolant Iodine Activity prior to Accident	
Pre-Existing Spike	60 μCi/gm of DE I-131 (See Table 6.11-15)
Accident-Initiated Spike	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Primary Coolant Iodine Appearance Rate Increase Due to the Accident-Initiated Spike	500 times equilibrium rate (See Table 6.11-16)
Duration of Accident-Initiated Spike	3.0 hours
Secondary Coolant Iodine Activity prior to Accident	0.10 μCi/gm of DE I-131 (See Table 6.11-15)
Iodine Chemical Form after Release to Atmosphere	
Elemental	97%
Organic	3%
Particulate (cesium iodide)	0%
Release Modeling	
Faulted Steam Generator Tube Leak Rate during Accident	432 gpd
Intact Steam Generator Tube Leak Rate during Accident	1008 gpd
Steam Generator Iodine Steam/Water Partition Coefficient	
Intact Steam Generator	0.01
Faulted Steam Generator	1.0
Time for RHR to take over cooling	29 hours
Time to Cool RCS Below 212°F and Stop Releases from Faulted Steam Generator	72 hours
Steam Release from Intact Steam Generators to Environment	
0-2 hours	402,000 lbm
2-29 hours	2,273,500 lbm
Steam Release from Faulted Steam Generator to Environment (during first 5 minutes)	142,400 lbm
Primary Coolant Mass	1.96E8 gm

Table 6.11-17 (Cont.)

Assumptions Used for Steamline Break Dose Analysis

Intact Steam Generator Secondary Mass	70,400 lbm/SG
Faulted Steam Generator Secondary Mass	142,400 lbm
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	1 minute
Control Room Atmospheric Dispersion (χ/Q) Factors	
Intact SG Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Faulted SG Releases:	
0 - 2 hours	1.18E-3 sec/m^3
2 - 8 hours	1.06E-3 sec/m^3
8 - 24 hours	5.42E-4 sec/m^3
24 - 96 hours	4.09E-4 sec/m^3
96 - 720 hours	3.27E-4 sec/m^3

Table 6.11-18 Assumptions Used for Locked Rotor Dose Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core Failing	5% of core
Fission Product Gap Fractions	
I-131	8% of core activity
Kr-85	10% of core activity
Other Iodines and Noble Gases	5% of core activity
Alkali Metals	12% of core activity
Radial Peaking Factor	1.7
RCS Iodines	1.0 µCi/gm DE I-131 (See Table 6.11-15)
RCS Noble Gases and Alkali Metals	Based on operation with 1.0% fuel defects (See Table 6.11-14)
Secondary Coolant Iodine Activity at Beginning of Event	0.10 µCi/gm DE I-131 (See Table 6.11-15 values)
Secondary Alkali Metal Activity at Beginning of Event	10% of Table 6.11-14 values
Iodine Chemical Form after Release to Atmosphere	
Elemental	97%
Organic	3%
Particulate (cesium iodide)	0%
Release Modeling	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day (total)
Steam Released from the Secondary Side	
0 - 2 hr	405,000 lbm
2 - 29 hr	2,303,000 lbm
Steam Generator Iodine Steam/Water Partition Coefficient	0.01
Steam Generator Alkali Metal Steam/Water Partition Coefficient	0.001
Termination of Releases	29 hours

Table 6.11-18 (Cont.) **Assumptions Used for Locked Rotor Dose Analysis**	
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	32 minutes
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3

Table 6.11-19

Assumptions Used for Rod Ejection Accident

Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core that Fail	10 (% of core)
Radial Peaking Factor	1.7
Fission Product Gap Fractions	
Iodines and Noble Gases	10% of core activity
Alkali Metals	12% of core activity
Fraction of Fuel Melting	0.25% of core
Fraction of Activity Released from Failed Fuel (gap activity)	100% for both containment leakage and steam generator steaming release paths
Fraction of Activity Released from Melted Fuel	
Noble Gases and Alkali Metals	100%
Iodines	25% for containment leakage release path 50% for steam generator steaming release path
RCS Iodines	1.0 μCi/gm DE I-131 (See Table 6.11-15)
RCS Noble Gases and Alkali Metals	Based on operation with 1% fuel defects (See Table 6.11-14)
Secondary Coolant Iodine Activity	0.10 μCi/gm DE I-131 (See Table 6.11-15)
Secondary Alkali Metal Activity	10% of Table 6.11-14 values
Containment Leakage Release Path	
Containment Net Free Volume	2.61E6 ft^3
Containment Leak Rates	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Iodine Chemical Form	4.85% elemental, 0.15% organic, and 95% particulate
Spray Removal in Containment	Not credited
Aerosol Removal by FCU Filters	
Number of FCUs Operating	3
FCU Filtered Flow	8000 cfm/FCU
Filter Efficiency	0.9
Time to Credit FCU Filtration Flow	60 sec.

Table 6.11-19 (Cont.)

Assumptions Used for Rod Ejection Accident

Steam Generator Steaming Release Path	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day
Duration of Primary-to-Secondary Leakage	1 hr
Steam Released from the Secondary Side	
0 - 2 hours	405,000 lbm
> 2 hours	0 lbm
Iodine Chemical Form after Release to Atmosphere	97% elemental, 3% organic
SG Iodine Steam/Water Partition Coefficient	0.01
SG Alkali Metal Steam/Water Partition Coefficient	0.001
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	140 seconds
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Containment Releases:	
0 - 2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3

Table 6.11-20

Assumptions Used for SGTR Dose Analysis

Source Term	
Nuclide Parameters	See Table 6.11-10
Primary Coolant Noble Gas Activity prior to Accident	Based on operation with 1.0% fuel defects (See Table 6.11-14)
Primary Coolant Iodine Activity Prior to Accident	
Pre-Existing Spike	60 μCi/gm of DE I-131 (See Table 6.11-15)
Accident-Initiated Spike	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Primary Coolant Iodine Appearance Rate Increase Due to the Accident-Initiated Spike	335 times equilibrium rate (See Table 6.11-16)
Duration of Accident-Initiated Spike	4.0 hours
Secondary Coolant Iodine Activity Prior to Accident	0.10 μCi/gm of DE I-131 (See Table 6.11-15)
Release Modeling	
Ruptured Steam Generator Steam Releases	See Table 6.4-2
Ruptured Steam Generator Break Flow Rate	See Table 6.4-2
Break-Flow Flashing Fractions	See Table 6.4-2
Intact Steam Generator Tube Leak Rate during Accident	432 gpd per steam generator
Steam Release from Intact Steam Generators to Environment	See Table 6.4-2
Steam Generator Iodine Steam/Water Partition Coefficient	
Ruptured and Intact Steam Generator Steam Release	0.01
Flashed Break Flow	1.0
Primary Coolant Mass	1.96E8 gm
Steam Generator Secondary Mass	2.88E7 gm/SG
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	7.53 minutes

Table 6.11-20 (Cont.) Assumptions Used for SGTR Dose Analysis	
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3

Table 6.11-21

Assumptions Used for SBLOCA Analysis

Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Fraction of Fuel Rods in Core that Fail	100% of core
Gap Fractions	
Iodine, Noble Gases and Alkali Metals	5% of core activity
Fraction of Fuel Melting	0% of core
Fraction of Activity Released from Failed Fuel (Gap Activity)	100%
RCS Noble Gas and Alkali Metal Activity Prior to Accident	Based on operation with 1.0% fuel defects (See Table 6.11-14)
RCS Iodine Activity Prior to Accident	1.0 µCi/gm of DE I-131 (See Table 6.11-15)
Containment Release Path	
Containment Net-Free Volume	2.61E6 (ft^3)
Containment Leak Rates	
0 - 24 hours	0.1 (weight %/day)
> 24 hours	0.05 (weight %/day)
Iodine Chemical Form	4.85% elemental, 0.15% organic and 95% particulate
Spray Removal in Containment	Not Credited
Aerosol Removal by FCU Filters	
Number of FCUs in Operation	3
FCU Filtered Flow	8000 cfm
Filter Efficiency	0.9
Time FCU Filtered Flow Begins	60 sec
Deposition Removal in Containment	Not credited

Table 6.11-21 (Cont.)

Assumptions Used for SBLOCA Analysis

Steam Generator Steaming Release Path	
Primary Coolant Mass	1.96E8 gm
Secondary Coolant Mass	1.277E8 gm (total)
Primary-to-Secondary Leak Rate	1440 gal/day total
Duration of Primary-to-Secondary Leakage	1 hr
Steam Released from the Secondary Side	
0 - 2 hours	405,000 lbm
> 2 hours	0 lbm
Steam Generator Iodine Steam/Water Partition Coefficient	0.01
Steam Generator Alkali Metal Steam/Water Partition Coefficient	0.001
Iodine Chemical Form after Release to Atmosphere	97% elemental, 3% organic
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	140 seconds
Control Room Atmospheric Dispersion (χ/Q) Factors	
Secondary Releases:	
0 - 2 hours	1.19E-3 sec/m^3
2 - 8 hours	1.12E-3 sec/m^3
8 - 24 hours	5.59E-4 sec/m^3
24 - 96 hours	4.27E-4 sec/m^3
96 - 720 hours	3.35E-4 sec/m^3
Containment Releases:	
0 -2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3

Table 6.11-22 Assumptions Used for LBLOCA Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Activity	See Table 6.11-13
Activity Release Timing	
Gap Release	Starting at 30 seconds, Ending at 30 minutes
Fuel Melt Release	Starting at 30 minutes Ending at 1.8 hours
Activity Release from the Fuel	
Noble Gases	5% gap, 95% fuel melt (100% total)
Iodines	5% gap, 35% fuel melt (40% total)
Alkali Metals	5% gap, 25% fuel melt (30% total)
Tellurium Metals	0% gap, 5% fuel melt (5% total)
Barium, Strontium	0% gap, 2% fuel melt (2% total)
Noble Metals	0% gap, 0.25% fuel melt (0.25% total)
Cerium Group	0% gap, 0.05% fuel melt (0.05% total)
Lanthanides	0% gap, 0.02% fuel melt (0.02% total)
Iodine Chemical Form in Containment	4.85% elemental, 0.15% organic and 95% particulate
Iodine Chemical Form Released to Atmosphere from ECCS Leakage	97% elemental, 3% organic
Containment Release Path	
Containment Net-Free Volume	2.61E6 ft^3
Sprayed Fraction	0.8
Containment Leak Rates	
0 - 24 hours	0.1 weight %/day
> 24 hours	0.05 weight %/day
Fan Cooler Flow Rate	34,000 cfm/unit
Number of Fan Coolers Credited	3
Time to Start Fan Coolers	1 minute
Fan Cooler Filtration	Not credited

Table 6.11-22 (Cont.) Assumptions Used for LBLOCA Analysis	
Spray Operation	
Time to Initiate Sprays	67 seconds
Spray Injection Duration	43.9 minutes
Delay Between End of Spray Injection Phase and Beginning of Spray Recirculation Phase	3 minutes
Termination of Spray Recirculation	4.0 hours
Injection Spray Flow Rate	2200 gpm
Recirculation Spray Flow Rate	1050 gpm
Spray Fall Height	118.5 feet
Removal Coefficients	
Elemental Iodine Injection Spray Removal	20.0 hr^{-1}
Particulate Injection Spray Removal	4.6 hr^{-1}
Elemental Iodine Recirculation Spray Removal	5.0 hr^{-1}
Particulate Recirculation Spray Removal	2.2 hr^{-1}
Sedimentation Particulate Removal in Unsprayed Region and in Sprayed Region after Spray Termination	0.1 hr^{-1}
DF Limit for Elemental Iodine Removal	200
DF Limit for Particulates Removal	1000
Sump Solution Leakage Release Path	
Credited Sump Mass	3.097E6 lbm
Sump Solution Leak Rate to Auxiliary Building	
0 - 4.0 hours	1 gal/hr
4.0 – 6.5 hours	0 gal/hr
> 6.5 hours	4 gal/hr
Iodine Airborne Fraction for Sump Solution Leakage to Auxiliary Building	
0 - 4 hours	0.10
4 – 6.5 hours	NA
>6.5 hours	0.027
Filtration of Activity Released by ECCS Leakage Outside Containment	Not credited

Table 6.11-22 (Cont.)

Assumptions Used for LBLOCA Analysis

Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	1 minute
Control Room Atmospheric Dispersion (χ/Q) Factors	
Containment Releases:	
0 - 2 hours	3.57E-4 sec/m^3
2 - 8 hours	3.12E-4 sec/m^3
8 - 24 hours	1.24E-4 sec/m^3
24 - 96 hours	1.06E-4 sec/m^3
96 - 720 hours	7.99E-5 sec/m^3
ECCS leakage:	
0 - 2 hours	5.93E-4 sec/m^3
2 - 8 hours	4.92E-4 sec/m^3
8 - 24 hours	2.06E-4 sec/m^3
24 - 96 hours	1.69E-4 sec/m^3
96 - 720 hours	1.26E-4 sec/m^3

Table 6.11-23	
Assumptions Used for GDT Rupture Dose Analysis	
Nuclide Parameters	See Table 6.11-10
GDT Inventory (Dose Equivalent Xe-133)	50,000 Ci
Duration of Release	5 minutes
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-24

Assumptions Used for VCT Rupture Dose Analysis

Nuclide Parameters	See Table 6.11-11
VCT Inventory (Ci)	See Table 6.11-6
Duration of Activity Release from Tank	5 minutes
Iodine Partition Coefficient for VCT Liquid	0.01
Primary Coolant Noble Gas Activity	1.0% fuel defect level (See Table 6.11-14)
Primary Coolant Initial Iodine Activity	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Letdown Flow Rate	132 gpm
Iodine Partition Coefficient for Letdown Releases	0.1
Letdown Line Demineralizer DF for Iodine	10
Time to Isolate Letdown Flow	30 minutes
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rate	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-25

Assumptions Used for HT Failure Dose Analysis

Nuclide Parameters	See Table 6.11-10
Duration of Activity Release from Tank	5 minutes
Iodine Partition Coefficient for HT Liquid	0.01
HT Volume	8500 ft^3
HT Full Level	80%
Primary Coolant Noble Gas Activity	1.0% fuel defect level (See Table 6.11-14)
Primary Coolant Initial Iodine Activity	1.0 μCi/gm of DE I-131 (See Table 6.11-15)
Tank Fill Time	24 hours
Letdown Demineralizer DF for Iodines	10
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Control Room Atmospheric Dispersion (χ/Q) factors	
Containment Vent Releases:	
0 - 2 hours	5.93E-4 sec/m^3
Time to Start Crediting Emergency Control Room HVAC	5 minutes

Table 6.11-26 Assumptions Used for FHA Analysis	
Source Term	
Nuclide Parameters	See Table 6.11-10
Core Total Fission Product Activity (with 84 Hours Decay)	See Table 6.11-27
Number of Fuel Assemblies	193
Radial Peaking Factor	1.70
Fuel Rod Gap Fraction	
I-131	12%
Kr-85	30%
Other Iodines and Noble Gases	10%
Fuel Damaged	One assembly
Time after Shutdown	84 hours
Water Depth	23 feet
Overall Iodine Scrubbing Factor	200
Noble Gases Scrubbing Factor	1
Filter Efficiency	No filtration of releases assumed
Isolation of Release	No isolation of releases assumed
Time to Release All Activity	2 hours
Offsite Atmospheric Dispersion Factors	See Table 6.11-11
Offsite Breathing Rates	See Table 6.11-11
Control Room Model	See Table 6.11-12
Time to Start Crediting Emergency Control Room HVAC	24 minutes
Control Room Atmospheric Dispersion (χ/Q) Factors	
Containment Vent:	
0 - 2 hours	5.93E-4 sec/m^3

Table 6.11-27

Core Fission Product Inventory 84 Hours after Shutdown Based on 3280.3 MWt (102% of 3216 MWt)

	Isotopic Inventory, curies
Iodine	
I-130	3.41E4
I-131	6.90E7
I-132	6.38E7
I-133	1.17E7
I-134	0.00E0
I-135	2.63E4
Noble Gases	
Kr-85m	5.62E1
Kr-85	1.11E6
Kr-87	0.00E0
Kr-88	0.00E0
Xe-131m	9.71E5
Xe-133m	2.78E6
Xe-133	1.36E8
Xe-135m	4.21E3
Xe-135	7.86E5
Xe-138	0.00E0

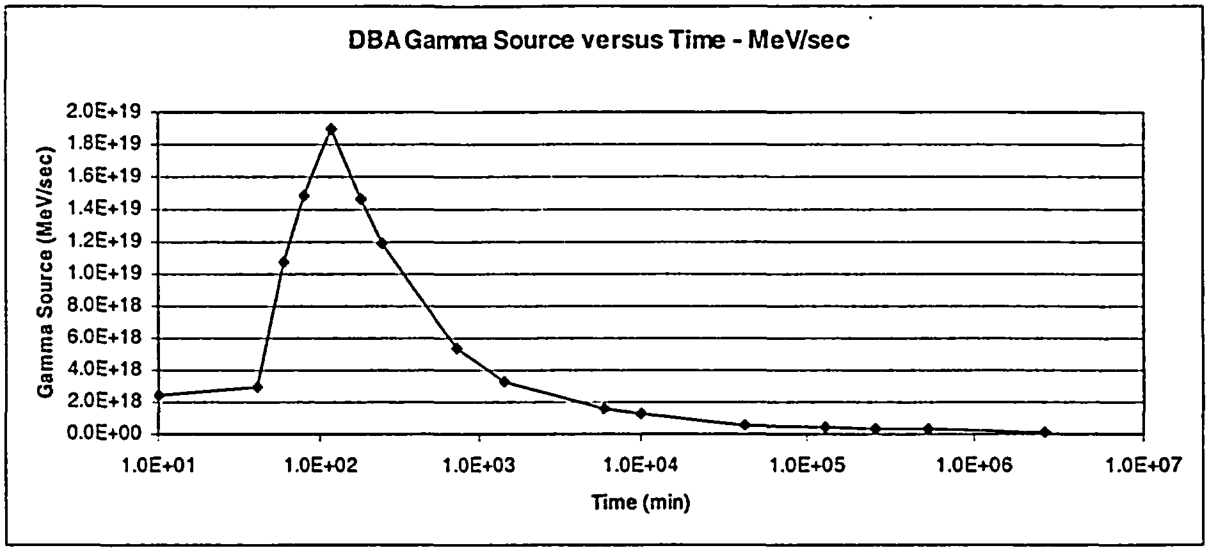


Figure 6.11-1

Containment Gamma Dose Rate vs. Time

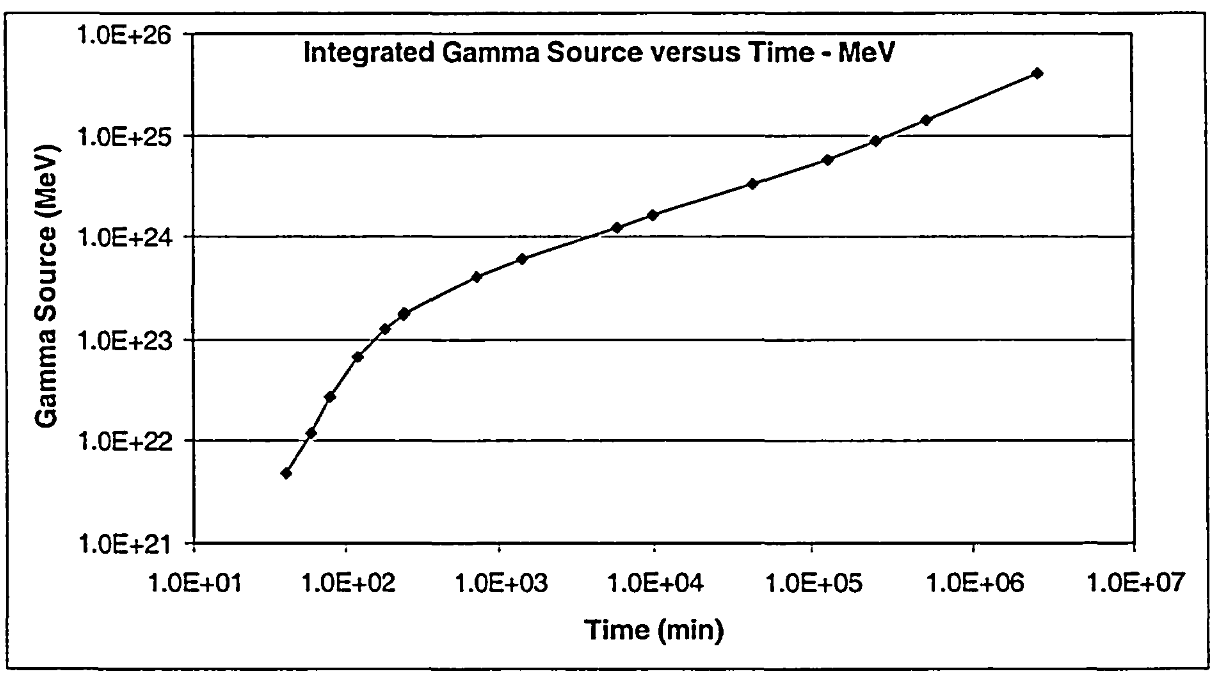


Figure 6.11-2

Integrated Containment Gamma Sources

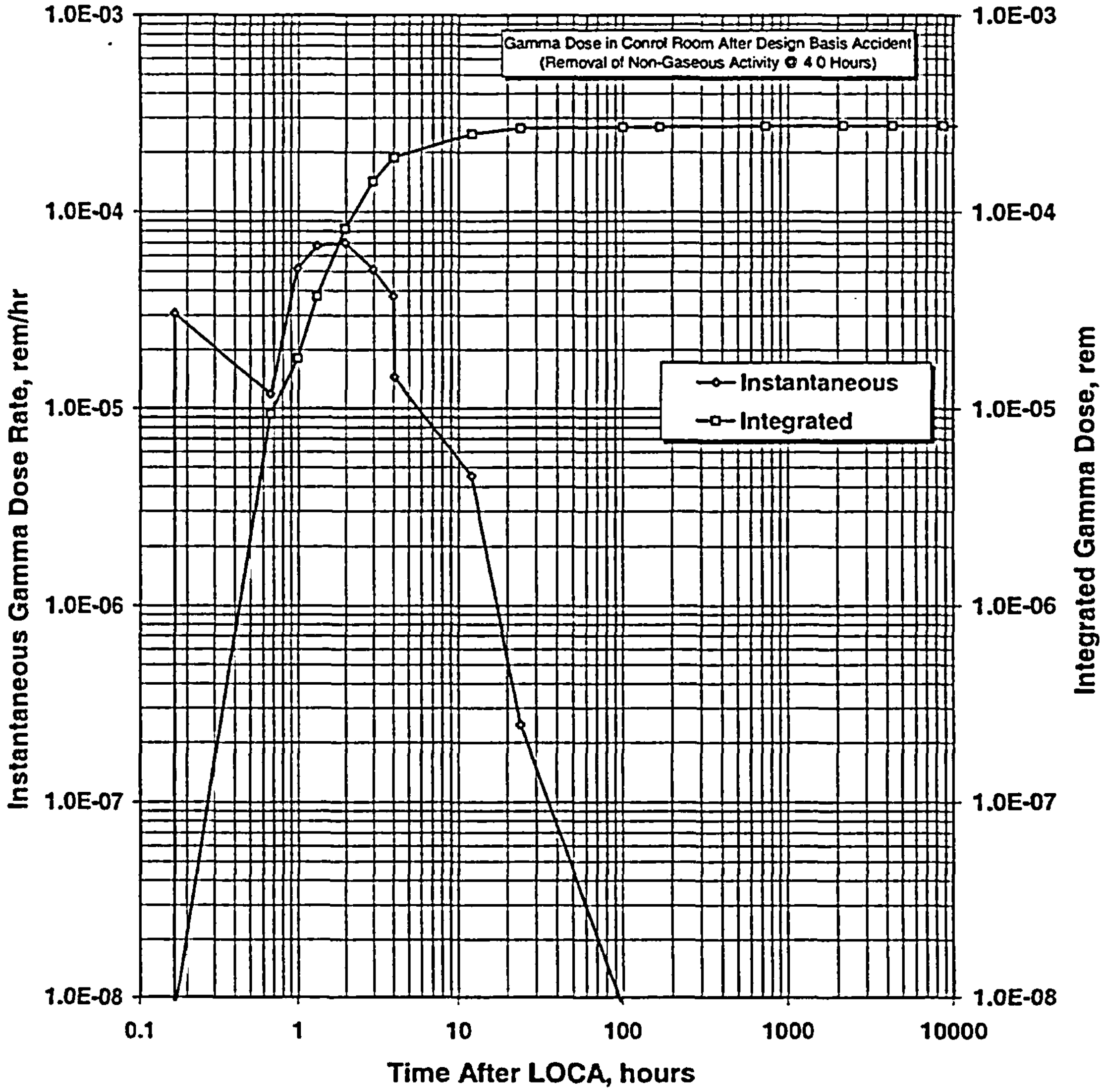


Figure 6.11-3

Direct Gamma Dose Rate and Integrated Dose in the Control Room Following a DBA

6.12 EOPs and EOP Setpoints

As a result of the Indian Point Unit 3 (IP3) stretch power uprate (SPU), the plant operating parameters have changed from the current design parameters. These include parameters that affect analyses and evaluations for plant operations and for plant accident responses. As a result of the parameter revisions, Emergency Operating Procedure (EOP) setpoints specified by the IP3 EOPs were reviewed to determine the potential effect from the changed power uprating parameters. Once this list of EOP setpoints was established, the new EOP setpoint calculations were performed.

To further ensure that the EOP setpoint documentation met the current generic requirements of Westinghouse Owners Group (WOG) Emergency Response Guidelines (ERGs), all relevant ERG Maintenance Direct Work Items (DWs) approved through August 2003 were reviewed, and necessary changes incorporated into the IP3 EOP setpoints and corresponding EOPs.

Based on the identified EOP setpoint changes, the IP3 EOPs were reviewed to identify changes resulting from the changed power uprating parameters and corresponding EOP setpoint changes.

These changes will be incorporated into the IP3 EOPs for use in the operator training program and in plant operations when the SPU is implemented.

6.13 Post-LOCA Hydrogen Generation

6.13.1 Introduction

An evaluation of the hydrogen generation in containment following a loss-of-coolant accident (LOCA) for the Indian Point Unit 3 (IP3) was performed based on updated parameters and assumptions that reflect the power uprate conditions. Westinghouse methodologies and the guidance provided in NRC Regulatory Guide (RG) 1.7 (Reference 1) were used in this assessment.

The hydrogen control strategies presented in the IP3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 2) reflect controlled vent flow and pressurization of containment, with provisions for an external hydrogen recombiner as a third alternative. The projected impact of removal by a recombiner on post-LOCA hydrogen accumulation was addressed in the Westinghouse evaluation. However, in the event of a LOCA design basis accident (DBA), plant personnel would calculate the effects of a release based on the actual conditions at the time of the release. Thus, it is not necessary to re-evaluate the pressurization and venting control methods, since actual plant conditions will be considered in ensuring that the resultant doses are within acceptable limits.

6.13.2 Input Parameters and Assumptions

A listing of the major parameters and assumptions are listed below in Table 6.13-1.

The remaining assumptions are consistent with NRC RG 1.7 (Reference 1).

6.13.3 Description of Analyses

The evaluation consists of the calculation of the production of hydrogen following a LOCA and the associated buildup of the concentration of hydrogen inside the containment. The concentrations are compared to the regulatory limit and the impact of removal of hydrogen by a hydrogen recombiner was determined. The sources of hydrogen that are considered in the analysis are:

- Zirconium water reaction
- Corrosion of materials
- Core and sump solution radiolysis
- Initial Reactor Coolant System (RCS) and containment inventories

The evaluations conducted for the various sources of hydrogen are summarized in the following paragraphs.

Zirconium - Water Reaction

The weight of analyzed zirconium cladding based on the current fuel load is 41,002 lbs. This value is noted to be less than the current IP3 UFSAR (Reference 2) loading of 47,947 lbs. However, the extra mass is based upon the total mass of zirconium cladding in the core (including zirconium outside the active core region that is not required to be analyzed in this event). Per 10CFR50.44 (Reference 3), the Zirc-water reaction involves only the region of the fuel that could exceed the temperature required for the chemical reaction of the cladding with the water or steam to occur (that is, the cladding in the active fuel region).

The amount of zirconium cladding that is assumed to undergo the Zirc-water reaction is 5 percent of the zirc cladding mass in the active core region. The amount of zirconium is mandated by 10CFR50 to be 5 times the fraction calculated in the 10CFR50.46 (Reference 4) ECCS performance criteria assessment. The assumption of 5 percent is an upper limit since 10CFR50 specifies that the calculated fraction not exceed 1 percent of the cladding in the active core region. Thus, 5 percent is 5 times the limiting calculated value and is a conservative and bounding value.

The total hydrogen produced from the Zirc-water reaction based on these conservative assumptions is 16,200 standard cubic feet (scf). This inventory is assumed to be instantaneously released to the containment atmosphere at the beginning of the LOCA.

Corrosion of Materials

The corrosion of materials in containment following a LOCA is a function of the temperature and pH of the solution in contact with the material, as well as the composition and surface area. The relationship of the aluminum corrosion rate with temperature and pH is illustrated in Figure 6.13-1. The default corrosion rates as a function of inverse temperature considered in the analysis is shown in this figure. The relationship used for the default aluminum corrosion rates is based on Oak Ridge National Laboratory (ORNL) measurements at a pH of about 9.5 (Reference 5).

Containment Temperature - The post-LOCA temperature profile used in establishing the material corrosion rates is graphically represented in Figure 6.13-2. The temperature profile is conservatively assumed to be that associated with only one train of safeguards in operation. It should also be noted that the long-term aluminum corrosion rate is maintained at or above 16 mg/dm^2/hr (200 mils/year) regardless of the prevailing temperature. This assumption is consistent with guidance provided in NRC RG 1.7 (Reference 1).

Spray/Sump pH - The pH of the spray and sump water is considered to be in the range of 7.0 to 10.0, per the IP3 UFSAR (Reference 2).

Corrodible Materials - Data relative to the inventory of corrodible materials inside containment (for example, aluminum) are tabulated in Table 6.13-2.

Core and Sump Solution Radiolysis

Hydrogen from sump and core radiolysis are time-dependent quantities that are a function of fission product decay energy. Core and sump radiolysis is calculated based on values of energy deposition in the core and sump solutions that reflect TID-14844 (Reference 6) release assumptions and the associated distribution of fission products, as defined in RG 1.7 (Reference 1). Plant operation with extended fuel cycles prior to a LOCA was considered. The default decay energy data were derived from the ORIGEN2.1 computer code (Reference 7) and bound decay energy data associated with typical Westinghouse fuel design parameters associated with extended (that is, 18- and 24-month) fuel cycles. The decay energies that are considered in the analyses reflect RG 1.7 assumptions relative to the amount of energy available for deposition in the sump and core solutions.

Initial RCS and Containment Inventories

The initial hydrogen inventory in the RCS prior to the LOCA includes hydrogen in the primary coolant as well as in the pressurizer gas space. The amount of hydrogen contained in the RCS is based on a pre-accident RCS hydrogen concentration of 50 cc/kg. This value is conservatively based on the value associated with the upper end of the operating range of 25 to 50 cc/kg that is recommended by Westinghouse and Electrical Power Research Institute (EPRI) (Reference 8). The hydrogen volume in the liquid, V_L, based on the maximum hydrogen concentration of 50 cc/kg, is 415 scf. An additional RCS H_2 inventory of 1059 scf is contained in the pressurizer steam space. This inventory is calculated based on no purge or leakage from the pressurizer, which results in a conservative estimate. Then, the total RCS inventory is:

$$V_{RCS} = V_L + V_P = 415 + 1059 = 1474 \text{ scf}$$

The associated hydrogen inventory is considered to be instantaneously released to the containment atmosphere.

Recombination

Removal from the containment atmosphere is conservatively assumed to be only by operation of a single electric hydrogen recombiner, and post-LOCA containment venting is not credited in the analyses.

The time at which recombination is assumed is at the end of the ninth day after a LOCA.

6.13.4 Acceptance Criteria for Analyses

RG 1.7 (Reference 1) indicates that the containment hydrogen concentration should remain below 4 volume-percent (v/o).

The initiation of recombination at the end of the ninth day satisfies the NRC Standard Review Plan (SRP) criteria for combustible gas control in containment. As stated in NUREG-0800, Section 6.2.5 (Reference 9):

"The proposed operation of the combustible gas control equipment, excluding containment atmosphere dilution (CAD) systems, is acceptable if there is an appropriate margin, e.g., on the order of 0.5 v/o, between the limiting hydrogen concentration limit and the hydrogen concentration at which the equipment would be actuated."

6.13.5 Results

The hydrogen production rates and containment inventories from the various sources of hydrogen are shown in Figures 6.13-3 and 6.13-4. The effects of recombination at various times are illustrated in Figure 6.13-5. The results indicate that, without recombination, a containment concentration of 3.0 v/o hydrogen is reached during the eleventh day after a LOCA, and a containment concentration of 4.0 v/o is reached during the twenty-fourth day after a LOCA. A concentration of 4.1 v/o is reached without recombination during the twenty-sixth day after a LOCA. Figure 6.13-5 shows that with no removal mechanisms in place, the hydrogen concentration builds up to about 4.4 v/o at 30 days following a LOCA. The figure also shows that operation of a single recombiner at a 100-scfm processing rate beginning at the time when the hydrogen concentration reaches 3.0 v/o results in an immediate termination of the buildup of hydrogen inside the containment. The decreasing hydrogen concentration after recombination is initiated indicates that the recombination rate exceeds the production rate.

The assumed minimum time from the beginning of a LOCA to start of recombiner operation is 9 days. As shown in Figure 6.13-5, the start of recombination at this time limits the containment hydrogen concentration to less than 4 v/o for the duration of the accident.

6.13.6 Conclusions

The start of recombination at 9 days after a LOCA limits the containment hydrogen concentration to less than 4 v/o for the duration of the accident. Thus, the regulatory limit is not exceeded.

6.13.7 References

1. NRC Regulatory Guide 1.7, *Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident*, Rev. 3, May 2003.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286, Rev. 10, January 6, 2001.

3. 10CFR50.44, *Combustible Gas Control for Nuclear Power Reactor*, September 16, 2003.

4. 10CFR50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors*, September 16, 2003.

5. Griess, J. C., and Barcarella, A. L., *Design Considerations of Reactor Containment Spray Systems – Part III. Corrosion of Plant Materials in Spray Solutions*, ORNL-TM-2412 (Part III), December 1969.

6. TID-14844, *Calculation of Distance Factors for Power and Test Reactor Sites*, Technical Information Document, Atomic Energy Commission – Division of Technical Information, March 23, 1962.

7. CCC-371, *ORIGEN2.1: Isotope Generation and Depletion Code – Matrix Exponential Method, RSICC Computer Code Collection*, Oak Ridge National Laboratory, February 1996.

8. *PWR Primary Water Chemistry Guidelines: Volume 1*, Revision 4, EPRI, Palo Alto, CA, 199-TR-105714-V1R4.

9. NUREG-0800, Branch Technical Position MTEB 6-1, *pH for Emergency Coolant Water for PWRs*, Rev. 2, July 1981.

Table 6.13-1 Major Parameters and Assumptions – Hydrogen Generation	
Core Thermal Power Rating[1]	3281 MWt
Containment Free Volume	2,610,000 ft^3
Containment Temperature at Accident Initiation	130°F
Fuel Cladding Mass Undergoing Zirc-Water Reaction	5.0%
Total Mass of Zirc in the Core	41,002 lbs.
RCS Hydrogen Concentration during Normal Operation	50 cc/kg
RCS Mass (normal pressurizer level)	518,182 lbs.
Pressurizer Volume	1834.4 ft^3
Pressurizer Level (normal operation)	50%
Hydrogen Recombiner Flow Rate	100 scfm

Note:

1. 3216 MWT multiplied by 1.02 to account for source uncertainties.

Table 6.13-2

Inventory of Aluminum Inside the Containment Building

Item Description	Weight (lbs)	Area (ft^2)
UFSAR Aluminum Sources		
Source, Intermediate, and Power Range Detectors	472	338
Process Instrumentation and Control Equipment	159	31
Paint	58	7480
Valve Parts inside Containment	230	86
Reactor Vessel Foil	269	10000
Flux Mapping Drive System	1950	335
Reactor Coolant Pump Motor Parts	125	12.8
Other Sources Included in Analysis		
CRDM Cooling Fan Blades	800	131.6
RCP conduit boxes	7.2	4
Rod Position Indicators	10.6	3.7
Others (filters, etc.)	25	25
Total Aluminum	4105.8	18447.1

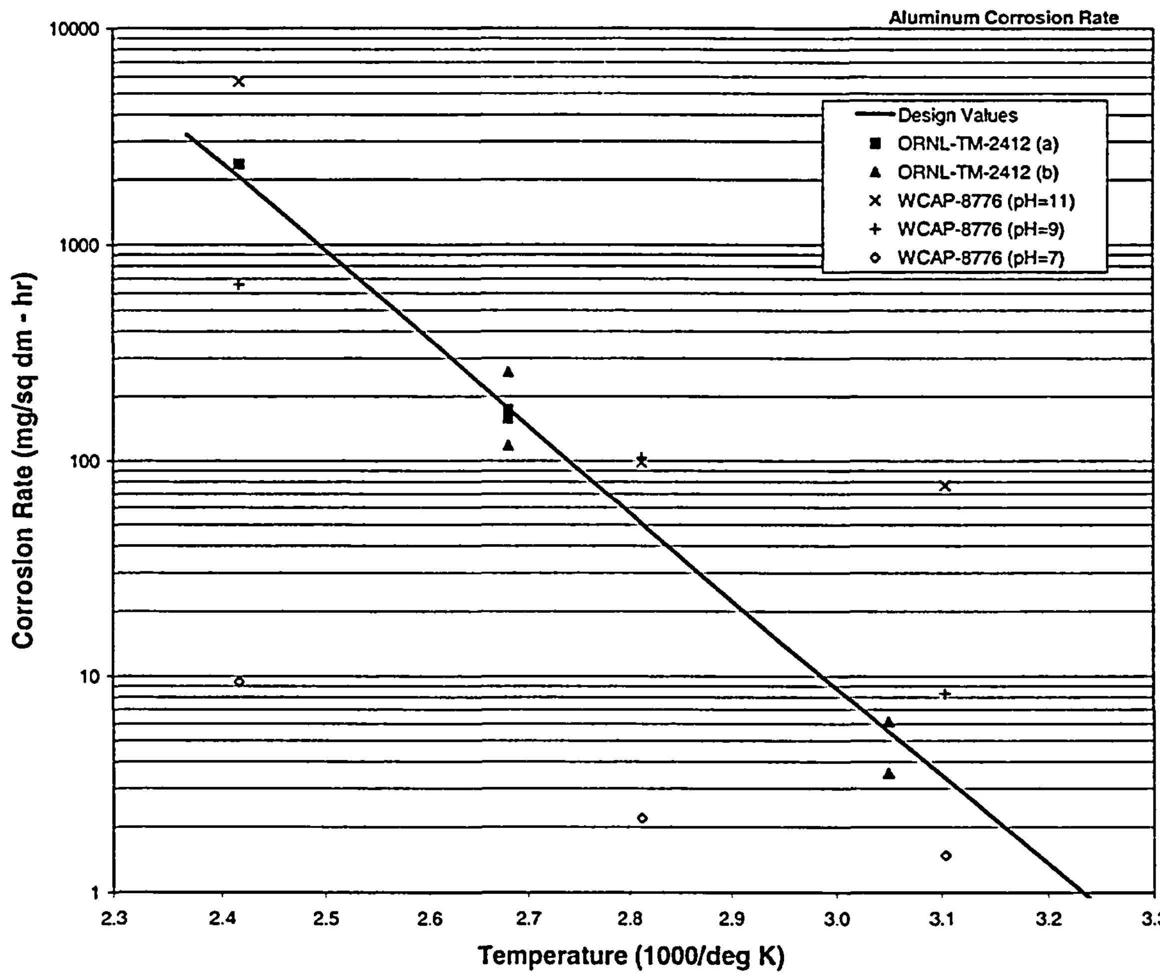


Figure 6.13-1

Aluminum Corrosion Rates in LOCA Environment

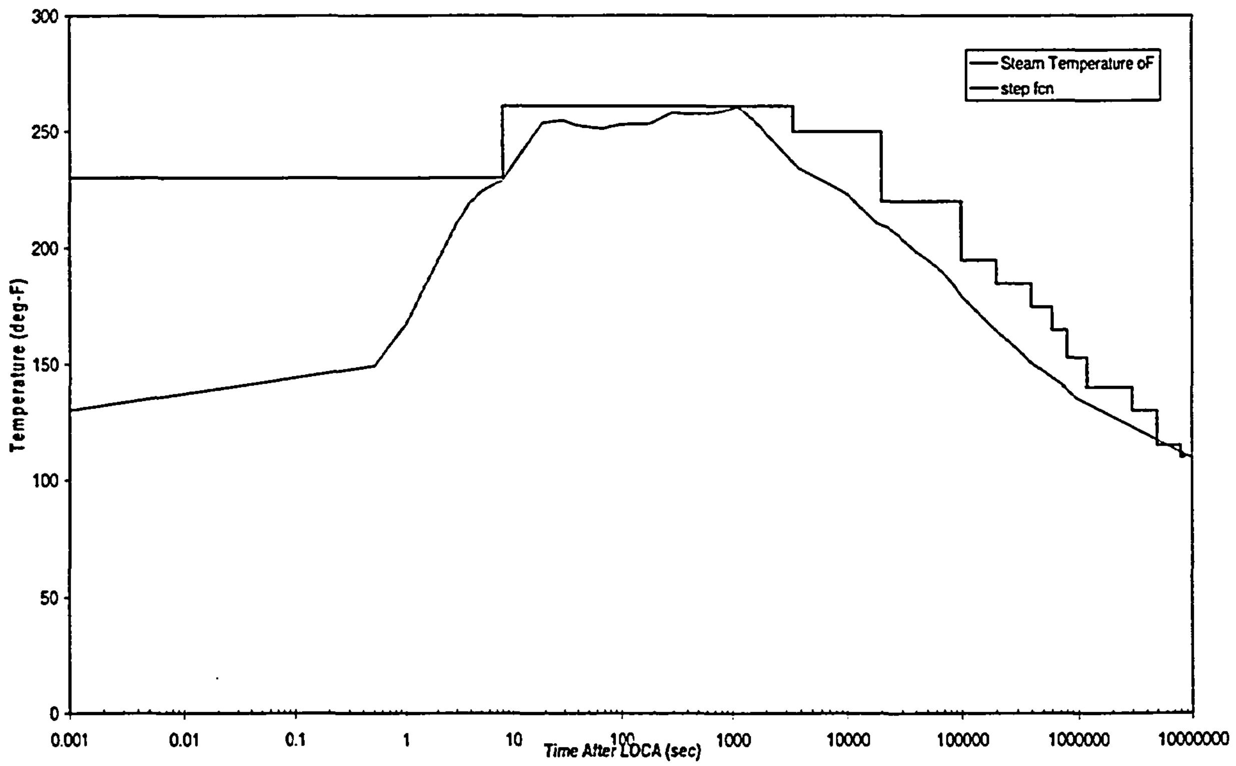


Figure 6.13-2

Post-LOCA Containment Temperatures

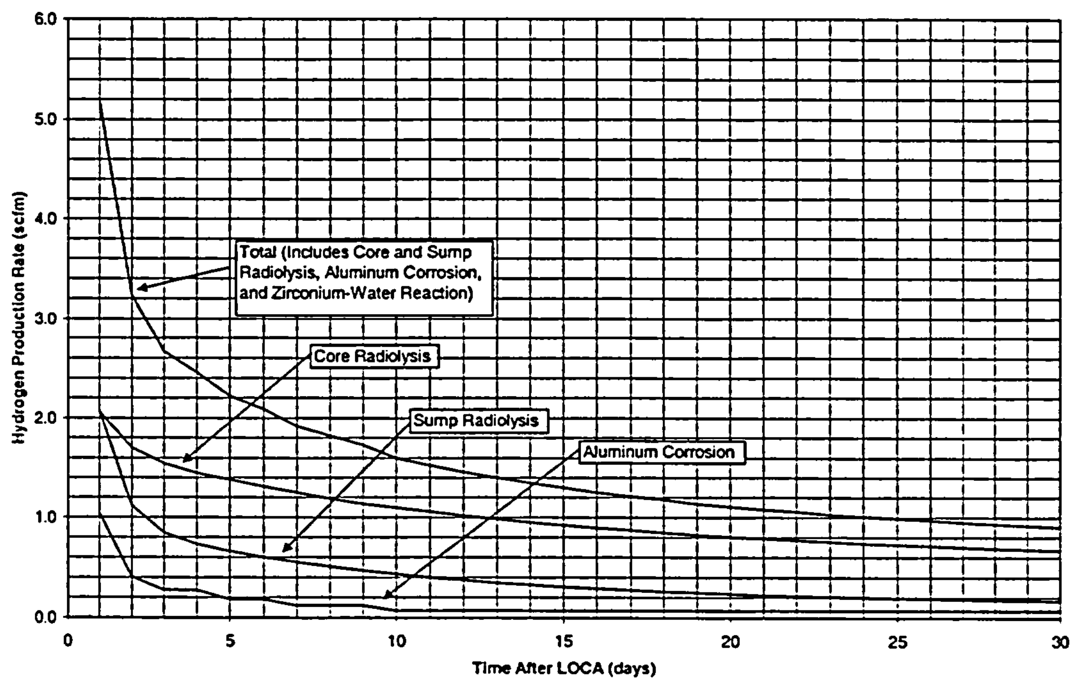


Figure 6.13-3

Containment Hydrogen Production Rate versus Time after LOCA

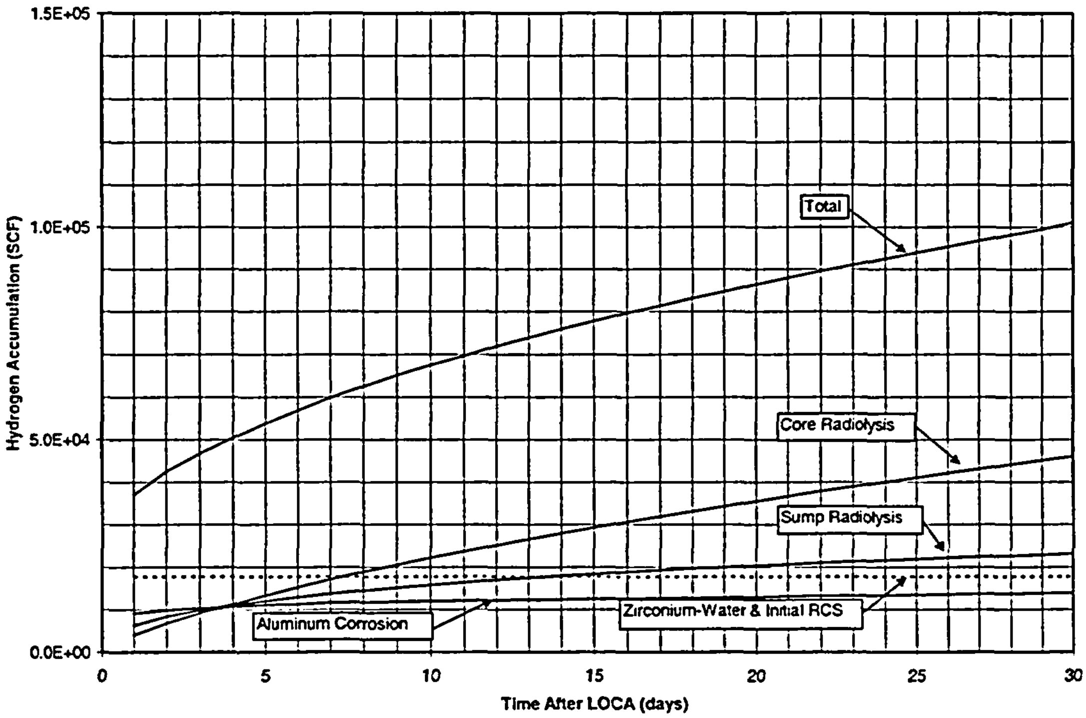


Figure 6.13-4

Hydrogen Accumulation from All Sources versus Time after LOCA

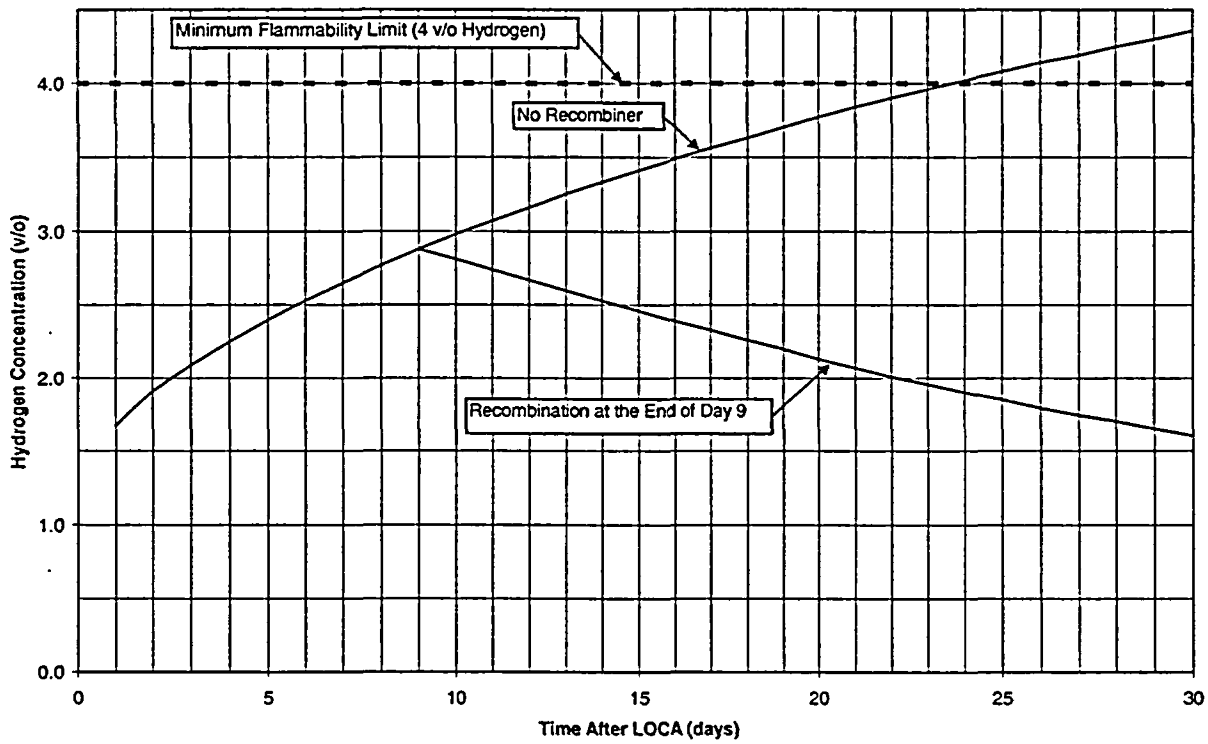


Figure 6.13-5

Containment Hydrogen Concentration versus Time after LOCA

7.0 NUCLEAR FUEL

This chapter discusses the analyses performed in support of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) in the nuclear fuel and fuel-related areas. Specifically, it addresses fuel thermal-hydraulic design, fuel core design, fuel rod performance, neutron fluence, and heat generation rates. The results and conclusions of each analysis can be found within the applicable subsection.

IP3 is currently operating in Cycle 13 with 15 x 15 VANTAGE+ fuel assemblies. Commencing in Cycle 14, it is planned 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. Westinghouse has already notified the NRC of this upgrade by letter LTR-NRC-04-8, dated February 6, 2004, "Fuel Criterion Evaluation Process (FCEP) Notification of the 15 x 15 Upgrade Design (Proprietary/Non-Proprietary)." The FCEP notification letter includes a description of the fuel upgrade. Neither the FCEP notification letter, nor the IP3 SPU License Amendment Request (LAR) requests or requires NRC approval of the subject fuel upgrade. Since the thermal limits of the existing fuel at IP3 are the same as those for the upgrade fuel, the upgraded fuel product is not needed to support the validity of the SPU analyses and implementation of the SPU. However, the upgrade fuel does provide additional margin for grid-to-rod fretting and to reduce the potential for incomplete rod cluster control assembly (RCCA) insertion. A mixed fuel core will exist at IP3 for the Cycle 14 reload; however, this has been addressed in, and bounded by, the various analyses (both for the mixed cores that will exist in transition and the final equilibrium core of the upgrade fuel) that have been performed to support the IP3 SPU (as described in this Licensing Report). The core design of each future cycle at IP will also explicitly consider the consequences of mixed cores that may exist for each cycle. For the purposes of the SPU analysis, fuel-related safety and design parameters have been chosen to bound the current VANTAGE+ fuel and the upgraded fuel assembly. These bounding parameters have been used in the safety and design analyses discussed in this section and in other sections of this report. If Entergy chooses to implement the upgraded fuel design for Cycle 14, licensing of this upgraded design will occur according to the NRC-approved Westinghouse Fuel Criteria Evaluation Process (FCEP) described in WCAP-12488-P-A. Furthermore applicability of the SPU safety analysis for the 15 x 15 upgraded fuel assembly will be evaluated or re-analyzed during the Cycle 14 reload safety evaluation in accordance with the reload safety evaluation methodology described in WCAP-9272-P-A.

Sections 7.1 through 7.4 discuss the results of analyses and evaluations that have been performed to show that the fuel and core designs as represented by the bounding parameters meet the acceptance criteria. The results of these analyses or evaluations will be reviewed and evaluated for each operating cycle as part of the cycle-specific reload safety evaluation in accordance with the reload safety evaluation methodology described in WCAP-9272-P-A. The cycle-specific reload safety evaluation will provide the technical and licensing bases for operation of the specific cycle at the licensed power level.

7.1 Fuel Design Features and Components

Fuel assemblies are designed to perform satisfactorily throughout their lifetime. The combined effects of the design basis loads are considered in evaluating the capability of fuel assemblies and their components to maintain structural integrity. This is necessary so that fuel assembly functional requirements are met while maintaining the core coolable geometry and the ability for reactor core safe shutdown.

The stretch power uprate (SPU) conditions result in changes to temperatures that affect loss-of-coolant accident (LOCA) forces. LOCA force changes result in changes to core plate motions, the effects of which have been incorporated into the analyses for the fuel assemblies. The SPU core power uprating does not increase operating or transient loads such that they will adversely affect fuel assembly functional requirements. Fuel assembly structural integrity is not affected and the core coolable geometry is maintained for the 15 x 15 VANTAGE+ (Zirlo™ with 0.422 rod and debris mitigating features) fuel assembly design and the 15 x 15 upgraded fuel assembly for Indian Point Unit 3 (IP3).

The top nozzle holddown spring analysis verified the fuel assembly holddown spring capability to maintain contact between the fuel assembly and the lower core plate at normal operating conditions. Thus, fuel assembly structural integrity is not affected by the SPU.

Other areas, such as fuel rod fretting, oxidation and hydriding of thimbles and grids, fuel rod growth gap, and guide thimble wear, were determined to be within the limits of the respective design criteria. It is concluded that the fuel assemblies are in conformance with all fuel assembly functional requirements at the SPU conditions.

Fuel Assembly Interface with Fuel Handling Provisions

The subject area of fuel handling has a bearing on nuclear safety because criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures must be avoided.

There are no changes to the fuel handling equipment for the SPU. Entergy plans to implement an upgrade to the current fuel design at Indian Point Unit 3 (IP3) starting with Cycle 14. The upgrade basically consists of an enhancement to grid design to provide additional margin for grid-to-rod fretting, and the use of tube-in-tube guide thimbles to reduce the potential for incomplete rod control cluster assembly (RCCA) insertion. (See Section 7.0) There are no planned changes to the fuel assembly characteristics that interface with the fuel handling equipment (that is, the lifting pockets of the top nozzle).

For the SPU, there is no change in the plant provisions for confinement of radioactive material, for shielding for radiation protection, or for criticality prevention. The source terms for normal operation (see subsection 6.11.5) have been evaluated for the nominal increase in SPU power level and determined to have a very small effect on normal operation dose. The dose effects from a fuel handling accident have been evaluated (see subsection 6.11.9.11) and have been determined to meet acceptance criteria. The maximum permissible fuel enrichment and spent fuel pit boron Technical Specification are unchanged. Therefore, the criticality considerations are unchanged.

7.2 Core Thermal-Hydraulic Design

7.2.1 Introduction

This section describes the core thermal-hydraulic analyses and evaluations performed in support of Indian Point Unit 3 (IP3) operation at a stretch power uprate (SPU) core power level of 3216 MWt over a range of Reactor Coolant System (RCS) temperatures (Table 2.1-2 in Section 2 of this report).

7.2.2 Input Parameters and Assumptions

Table 7.2-1 summarizes the thermal-hydraulic design parameters used in the departure from nucleate boiling ratio (DNBR) analyses. The core inlet temperature used in the DNBR analyses is based on the upper bound of the RCS temperature range for the SPU conditions. Use of the upper bound temperature is conservative for the DNBR analyses. The DNBR analyses also assume that the SPU core designs are composed of 15 x 15 VANTAGE+ and 15 x 15 upgraded fuel assemblies.

7.2.3 Description of Analyses and Evaluations

7.2.3.1 Calculation Methods

The thermal-hydraulic design criteria and methods for the SPU remain the same as those presented in the *IP3 Updated Final Safety Analysis Report* (UFSAR) and the 1.4-percent Measurement Uncertainty Recapture (MUR) Report (References 1 and 2). The WRB-1 departure from nucleate boiling (DNB) correlation and the Revised Thermal Design Procedure (RTDP) DNB methodology (Reference 3) continue to be used for the SPU DNB analysis with the 15 x 15 VANTAGE+ and upgraded fuel assemblies. The W-3 DNB correlation is used for events where the conditions fall outside the applicable range of the WRB-1 correlation. The Westinghouse version of the VIPRE-01 (VIPRE) code (Reference 4) is used for DNBR calculations with the WRB-1 and the W-3 DNB correlations. The use of VIPRE for the SPU analysis is in full compliance with the conditions specified in the NRC *Safety Evaluation Report* (SER) in WCAP-14565-P-A (Reference 4).

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain DNB sensitivity factors. Based on the DNB sensitivity factors, RTDP design limit DNBR values were determined such that there was at least a 95-percent probability at a 95-percent confidence level that DNB would not occur on the most limiting fuel

rod during normal operation, operational transients, or transient conditions arising from faults of moderate frequency (Condition I and II events as defined in the IP3 USFAR [Reference 1]).

Uncertainties in plant operating parameters (pressurizer pressure, primary coolant temperature, reactor power, and RCS flow) are considered in the RTDP DNBR analysis. Only the random portion of each plant operating parameter uncertainty is included in the statistical combination for RTDP. Any adverse instrumentation bias is treated either as a direct DNBR penalty or a direct analysis input.

The RTDP design limit DNBR values specified in the 1.4-percent MUR report (Reference 2) for IP3 were revised for the SPU to 1.22/1.23 (for thimble/typical cells).

In addition to the above considerations for uncertainties, DNBR margin was obtained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. Sufficient DNBR margin was conservatively maintained in the safety analysis DNBR limits to offset the rod bow, transition core, and plant operating parameter bias DNBR penalties. The net remaining DNBR margin, after considering penalties, is available for operating and design flexibility.

As noted in the USFAR and in the 1.4-percent MUR Report (References 1 and 2), the Standard Thermal Design Procedure (STDP) is used for those analyses where RTDP is not applicable. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

7.2.3.2 DNB Performance

The current DNBR analyses of record for IP3 are primarily those that were performed to support the SPU using VANTAGE+ fuel. All DNBR analyses performed for the SPU for a core power level of 3216 MWt are bounding for operation using both 15x15 VANTAGE+ and upgraded fuels. A comparison of the current thermal-hydraulic parameters and the SPU parameters is shown in Table 7.2-1.

To support the operation of IP3 at SPU conditions, DNBR reanalysis was required to define new core limits, axial offset limits, and Condition II accident acceptability. The accident DNB analyses to support the SPU are addressed below.

7.2.3.2.1 Loss of Flow

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the loss-of-flow (LOF) transient conditions at a 95-percent confidence level. This criterion is met if the minimum DNBR for the LOF evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the loss-of-flow accident was performed for SPU conditions. Three cases, including partial-loss-of-flow (PLOF), complete-loss-of-flow (CLOF), and CLOF-under frequency (CLOF-UF) were checked to ensure the limiting scenario was identified. The effect of updated fuel temperatures was included in the analysis of this event (subsection 7.2.3.3). The CLOF-UF case resulted in the lowest minimum DNBR. The minimum DNBRs calculated for each of the three cases were greater than the new safety analysis DNBRs, thereby demonstrating compliance to the DNB design criterion for this event.

7.2.3.2.2 Locked Rotor

DNB Design Criteria

As shown in the radiological consequences analysis (see subsection 6.11.9), the locked rotor (LR) event (Condition IV event) is allowed to have 5-percent fuel rod failure. This criterion is met if there are less than or equal to 5 percent of the rods in DNB for the LR evaluation.

Evaluations

The analysis of the locked rotor accident was performed for SPU conditions. The locked rotor accident is classified as a Condition IV event. To calculate the radiation release as a consequence of the accident, DNB calculations were performed to quantify the inventory of rods that would experience DNB and be conservatively presumed to fail. For IP3, the analysis indicates that there would be no rods in DNB due to the locked rotor accident. The radiological consequences analysis conservatively assumed 5 percent of the fuel rods as failed rods and showed that the site dose limits were met (see subsection 6.11.9 of this report).

7.2.3.2.3 Feedwater Malfunction

The core response for the feedwater malfunction event at hot zero power (HZP) was bounded by the steamline break core response. All DNBR design criteria are met for the feedwater malfunction event at zero power. The feedwater malfunction at hot full power (HFP) conditions is presented in subsection 6.3.9 of this report.

7.2.3.2.4 Dropped Rod

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the dropped rod event at a 95-percent confidence level. This criterion is met if the dropped rod limit lines, which would result in the safety analysis limit DNBR being reached, are met.

Evaluations

Dropped rod limit lines were calculated to address the acceptability of the plant's response to this accident scenario. The limit lines were calculated based on the reference power shape. The loci of points that would result in the safety-limit DNBR being reached were defined for a wide span of core conditions (inlet temperature, power, and pressure).

The effects on core conditions, including power distribution, are demonstrated to remain within the bounds represented by the dropped rod limit lines. There was no explicit DNBR calculation performed for the dropped rod event. The SPU core design met the limit lines. Calculation of the effects of the accident on the core was checked cycle-by-cycle, ensuring compliance to the DNB criterion for each cycle.

7.2.3.2.5 Steamline Break

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the steamline break (SLB) events at a 95-percent confidence level. This criterion is met if the minimum DNBR for the SLB evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the hot zero power (HZP) steamline break event was performed for SPU conditions. The mechanistic STDP methodology was applied in the HZP steamline break analysis. For the STDP application, the W-3 DNBR correlation limit for this transient is 1.45. The calculated minimum DNBR, which is reduced to account for any DNBR penalties applicable at this transient condition, is well above the W-3 DNBR correlation limit of 1.45.

7.2.3.2.6 Rod Withdrawal from Subcritical

DNB Design Criteria

There will be at least a 95-percent probability that DNB will not occur on the limiting fuel rods during the rod withdrawal from subcritical (RWFS) event at a 95-percent confidence level. This criterion is met if the minimum DNBR for the RWFS evaluation is above the safety analysis limit DNBR.

Evaluations

The DNB analysis of the rod withdrawal from subcritical accident was performed for SPU conditions.

By nature of the accident, a bottom-skewed power shape was conservatively applied. A power excursion, due to the removed rod bank, would develop more prominently in the lower part of the core. For this calculation, a conservative generic power shape was applied. To preserve applicability of the critical heat flux correlation, two calculations were required for this accident. For fuel assembly spans below the first mixing vane grid, the W-3 correlation was applied. For fuel assembly spans above the mixing grid, the WRB-1 correlation was applied, consistent with other DNBR confirmation calculations. Also, because of the zero power precondition of this event, the methodology that convolutes uncertainty terms to set limits was not appropriate, so the mechanistic STDP was applied. For the STDP application, the DNBR limit applied was the correlation limit DNBR, since uncertainties were mechanistically applied on the calculation input. For the W-3 correlation, this value was 1.30. For the WRB-1 correlation, this value was 1.17.

Calculations have been completed for each span and the results showed that the predicted DNBR remained above the respective correlation limit DNBR, thereby demonstrating compliance to the DNB design criterion for this event.

7.2.3.3 Fuel Temperatures and Rod Internal Pressures

The fuel temperatures and rod internal pressures for the SPU safety analysis for VANTAGE+ and upgraded fuel were based on ZIRLO™ cladding design. The NRC-approved Westinghouse PAD 4.0 fuel performance models (References 5 and 6) were used in the fuel temperature and rod internal pressure analyses. The integral fuel burnable absorber (IFBA) and non-IFBA fuel temperatures and/or rod internal pressures were used as initial conditions for LOCA and non-LOCA transients. Also, based on the fuel temperature analysis, the linear power limit to preclude fuel centerline melting was determined to be 22.7 kW/ft and was met at the SPU conditions.

7.2.4 Acceptance Criteria

The acceptance criteria are contained in each subsection under subsection 7.2.3.2 of this report.

7.2.5 Results and Conclusions

Core thermal-hydraulic analyses and evaluations were performed in support of IP3 operation at the SPU core power level of 3216 MWt over a range of RCS temperatures. The results showed that the core thermal-hydraulic design criteria listed in subsection 7.2.3.2 and the UFSAR (Reference 1) are satisfied.

7.2.6 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report,* Rev. 18, Docket No. 50-286.

2. *Indian Point Nuclear Generating Unit No. 3, 1.4-Percent Measurement Uncertainty Recapture Power Uprate License Amendment Request Package*, Entergy Nuclear Operations, Inc., May 2002.

3. WCAP-11397-A (Nonproprietary) and WCAP-11397-P-A (Proprietary), *Revised Thermal Design Procedure*, A. J. Friedland and S. Ray, April 1989.

4. WCAP-14565-A (Proprietary) and WCAP-15306 (Nonproprietary), *VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis*, Y. X. Sung, et al., October 1999.

5. 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. WCAP-12610-P-A, *VANTAGE+ Fuel Assembly Reference Core Report*, S. L. Davidson and T. L. Ryan, April 1995.

Table 7.2-1 Thermal-Hydraulic Design Parameters for IP3		
Thermal-Hydraulic Design Parameters	**Current**	**SPU**
Reactor Core Heat Output, MWt	3067.4	3216
Reactor Core Heat Output, 10^6 Btu/hr	10,468	10,973
Heat Generated in Fuel, %	97.4	97.4
Pressurizer Pressure, Nominal, psia	2250	2250
$F_{\Delta H}$, Nuclear Enthalpy Rise Hot Channel Factor	1.70	1.70
Part Power Multiplier for $F_{\Delta H}$	[1+0.3(1-P)]	[1+0.3(1-P)]
Minimum DNBR at Nominal Conditions (using RTDP) Typical Flow Channel Thimble (cold wall) Flow Channel	 2.62 2.51	 2.60[1] 2.50[1]
Design Limit DNBR Typical Flow Channel Thimble (cold wall) Flow Channel	 1.23 1.23	 1.23 1.22
DNB Correlation[2]	WRB-1	WRB-1
Vessel Inlet Minimum Measured Flow Rate, MMF, (including bypass) gpm	 330,800	 364,700
Vessel Inlet Thermal Design Flow Rate, TDF, (including bypass) gpm	 323,600	 354,400
Core Inlet Flow Rate (excluding total bypass, based on TDF) gpm	 306,800	 327,800
Fuel Assembly Flow Area for Heat Transfer, ft^2	51.54	51.54
Core Inlet Mass Velocity (based on TDF), ft/sec	13.3	14.2
Tube plugging level, %	24.0	10.0
Nominal Vessel/Core Inlet Temperature, °F	542.5	541.0
Vessel Average Temperature, °F	574.7	572.0
Core Average Temperature, °F	577.9	575.8
Vessel Outlet Temperature, °F	606.9	603.0
Average Temperature Rise in Vessel, °F	64.4	62.0
Average Temperature Rise in Core, °F	67.5	66.5

Table 7.2-1 (Cont.) Thermal-Hydraulic Design Parameters for IP3		
Thermal-Hydraulic Design Parameters	**Current**	**SPU**
Heat Transfer		
Active Heat Transfer Surface Area, ft^2	52,100	52,100
Average Heat Flux, Btu/hr-ft^2	196,000	205,200
Average Linear Power, kW/ft	6.34	6.64
Peak Linear Power for Normal Operation, kW/ft	15.3[3]	16.6[3]
Temperature Limit for Prevention of Centerline Melt, °F	4700	4700

Notes:

1. The minimum nominal DNBRs are conservatively listed for both VANTAGE+ and upgraded fuel.
2. See subsection 3.2.2.8 of Reference 1 for the use of the W-3 DNB correlation.
3. This power level is based on a peaking factor (F_Q) of 2.5 for SPU conditions and 2.42 for current operating conditions.

7.3 Fuel Core Design

7.3.1 Introduction

The nuclear design portion of the Indian Point Unit 3 (IP3) stretch power uprate (SPU) core analysis determined the effect of the uprate on the key safety parameters. These safety parameters were used as input to the Indian Point Unit 3 *Updated Final Safety Analysis Report* (UFSAR) (Reference 1) Chapter 14 accident analyses.

7.3.2 Input Parameters and Assumptions

The nuclear design analyses demonstrated the acceptability of operation at the SPU core power level of 3216 MWt consistent with parameters in Section 2 of this report.

7.3.3 Description of Analyses and Evaluations

To satisfy these objectives, conceptual models were developed that followed the uprate transition to an equilibrium cycle. Fuel management strategies similar to those used in recent cycles were assumed in developing the models. The SPU assumed a core thermal power level of 3168 MWt during the first transition cycle and 3216 MWt in the second and third transition cycles. Key safety parameters were then evaluated to determine the expected ranges of variation in the parameters. The key safety parameters are those described in the standard reload design methodology (Reference 2). Some of these parameters, such as shutdown margin, were sensitive to the fuel management and loading pattern characteristics.

The observed variation in the parameters that were sensitive to loading patterns at SPU conditions were typical of the normal cycle-to-cycle variations for non-transition fuel reloads. Many of the key safety parameters were dependent on the loading patterns.

7.3.3.1 Methodology

All nuclear design analysis in support of the IP3 SPU was performed using standard Westinghouse core reload methodology described in WCAP-9272-P-A (Reference 2) with the Westinghouse PHOENIX-P and ANC codes described in WCAP-11596-P-A and WCAP-10965-P-A (References 3 and 4). These licensed methods and models have been used for IP3 and other previous Westinghouse reload fuel designs with and without uprating. No changes to the nuclear design philosophy, methods, or models, are necessary due to the SPU.

The reload design philosophy used by Westinghouse includes an evaluation of the reload core key safety parameters that comprises the nuclear-design-dependent input to the reload fuel safety evaluation for each reload cycle. This philosophy is described in WCAP-9272-P-A (Reference 2). These key safety parameters will be evaluated for each IP3 reload cycle. If one or more of the key parameters fall outside the bounds assumed in the safety analyses, the affected transients will be reevaluated and the results documented in the *Reload Safety Evaluation Report* (RSE) for that cycle. The main objective of the uprating core analyses was to determine, prior to the cycle-specific reload design, if the previously used bounds for the key safety parameters remained applicable. The results of these analyses are described below.

7.3.3.2 Physics Characteristics and Key Safety Parameters

Conceptual core loading patterns were constructed to be representative of future IP3 cores. Table 7.3-1 compares the safety parameter ranges considered for the IP3 current designs and for the SPU.

The comparison in Table 7.3-1 shows that the SPU core did not have any marked deviations from the core design at 3067.4 MWt. Of note is a small change in the hot full power (HFP) most-negative- and least-negative-doppler-only power coefficients, which were analyzed over a slightly larger range in order to achieve consistency with the Indian Point Unit 2 (IP2) SPU analysis.

Shutdown margin and maximum boron concentrations are two parameters that are loading-pattern-dependent and the core design must be developed such that these constraints are met. The shutdown margin requirement of 1300 pcm is primarily a function of the power defect from full power to hot zero power (HZP) at the time of trip, and the type of fuel that is placed under control rod locations. The power defect is set by the enrichments required to achieve the design cycle length and the operating temperature. The core design can govern the amount of shutdown margin by increasing the amount of fresh fuel in control rod locations. Since the SPU conditions significantly increase the power defect, the required amount of shutdown margin is a loading pattern constraint that must be met in order to consider the loading pattern acceptable. Maximum boron concentration is a function of the feed enrichment needed to achieve the cycle lifetime but also of the fuel management strategy used for the loading pattern. As the maximum boron concentrations are initial or final conditions, they are also a design constraint that must be considered at the time of loading pattern development.

7.3.3.3 Power Distributions and Peaking Factors

Loading patterns were developed and modeled based on the projected energy requirements for the SPU. These models were not intended to represent limiting loading patterns but were developed with the intent to show that enough margin exists between typical safety parameter values and the corresponding limits to allow flexibility in designing actual reload cores.

7.3.3.4 Radial Power Distribution Effects

Assembly average powers at beginning of life (BOL), middle of life (MOL), and end of life (EOL) were calculated using the SPU core models for different fuel management techniques. The effect on the radial power distribution due to the SPU conditions was small when compared to loading patterns for similar fuel management practices at nominal power conditions. The effects of these radial power distribution differences on rod worths and on off-nominal condition peaking factors were small and were well within normal cycle-to-cycle variation in these parameters.

7.3.3.5 Axial Power Distribution and FQ(z) Effects

The axial power distribution effect of the SPU conditions shows only a small sensitivity to the uprate.

As part of the reload design process, a cycle-specific final acceptance criteria (FAC) analysis based on constant axial offset control (CAOC) operation (Reference 5) check is performed that implicitly includes the axial effects of the uprating. Load follow simulations were performed through the power range to generate axial power shapes that were typical of Condition I operation. The results of the FAC analysis for this report showed that the total peaking factor (FQ) was acceptable. Therefore, it is expected that all reload cores at SPU conditions will also be acceptable.

7.3.4 Conclusions

In summary, implementing the SPU will not cause changes to the current nuclear design bases given in the UFSAR. The effect of the SPU on peaking factors, rod worths, reactivity coefficients, shutdown margin, and kinetics parameters will be well within normal cycle-to-cycle variation of these values or controlled by the core design, and will be addressed on a cycle-specific basis, consistent with the reload safety evaluation methodology (Reference 2). The ranges of key safety parameters as reported in Table 7.3-1 remain valid and bounding for the SPU.

7.3.5 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286, November 2001.

2. WCAP-9272-P-A, *Westinghouse Reload Safety Evaluation Methodology*, S. L. Davidson et al., July 1985.

3. WCAP-11596-P-A, *Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores*, T. Q. Nguyen et al., June 1988.

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

5. WCAP-8385 (Proprietary), *Power Distribution Control and Load Following Procedures*, T. Morita et al., September 1974.

7.4 Fuel Rod Design and Performance

7.4.1 Introduction

Fuel rod design analyses were performed to assess the potential effects that the SPU operating conditions for Indian Point Unit 3 (IP3) would have on meeting fuel rod design criteria.

7.4.2 Description of Analyses, Acceptance Criteria, and Results

The fuel rod design analyses modeled 15 x 15, 8-inch annular blanket, 1.25X integral fuel burnable absorber (IFBA), ZIRLO™ clad fuel rods irradiated for up to 4 cycles at SPU conditions.

Based on the history of IP3, operation should be limited to a maximum vessel average temperature of 572.0°F is recommended to avoid potential clad fatigue and rod internal pressure violations for operation at the SPU power level. Representative rod power histories and axial power shapes, generated by the NRC-approved Advanced Nodal Code (ANC) (References 1 and 2) were analyzed. The NRC-approved Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were also used in the analyses. PAD is the main design tool for evaluating fuel rod performance, calculating the inter-related effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

The following sections summarize the effect of the core power uprating on the fuel rod design criteria most affected by the SPU core power. The fuel rod design criteria affected were rod internal pressure, clad corrosion, clad stress, and clad strain criteria. Other fuel rod design criteria were not significantly affected by a core power uprating.

7.4.2.1 Rod Internal Pressure

Design Basis

The fuel system will not be damaged due to excessive fuel rod internal pressure.

Acceptance Limit

The internal pressure of the lead fuel rod in the reactor will be limited to a value below that which could cause the diametral gap to increase due to outward clad creep during steady state operation or cause extensive departure from nucleate boiling (DNB) propagation to occur.

Design Evaluation

The analyses showed that meeting the rod internal pressure criterion was most affected by the SPU increase in core power level. The higher power levels resulted in higher fuel operating temperatures with a potential for increased fission gas release. Analysis of the representative rod power histories indicated that the higher duty fuel rods have this potential for increased fission gas release resulting in higher rod internal pressures. The IFBA loading was reduced from 1.5X to 1.25X to meet the rod internal pressure criterion. The rod internal pressure criterion can be met under uprated core conditions with a maximum vessel average temperature of 572.0°F by appropriate cycle-specific core design.

7.4.2.2 Clad Corrosion

Design Basis

The fuel system will not be damaged due to excessive fuel clad oxidation. The fuel system will be operated to prevent significant degradation of mechanical properties of the clad at low temperatures, due to hydrogen embrittlement caused by formation of zirconium hydride platelets.

Acceptance Limit

The calculated fuel clad temperature (metal-oxide interface temperature) will be less than the license limit [ ]^{a,c} for ZIRLO clad fuel during steady state operation. For Condition II events, the calculated fuel clad temperature will not exceed the license limit [ ]^{a,c} for ZIRLO clad fuel. The hydrogen pickup level in the fuel clad will be less than or equal to the license limit [ ]^{a,c} at the end of fuel operation.

Design Evaluation

The SPU conditions result in increased operating temperatures for the fuel clad due to the increased fuel rod average power rating. Since the corrosion process is a strong function of fuel clad temperature, the SPU will affect meeting these criteria. Analysis of the representative rod power histories indicated that the corrosion design criteria will be satisfied for the higher duty fuel rods at the SPU core conditions.

7.4.2.3 Clad Fatigue

Design Basis

The fuel system will not be damaged due to excessive fuel clad fatigue.

Acceptance Limit

The fatigue life usage factor will be less than 1.0 or, for a given strain range, the number of strain fatigue cycles will be less than those required for failure, considering a minimum safety factor of 2 on the stress amplitude or a minimum safety factor of 20 on the number of cycles, whichever is more conservative.

Design Evaluation

The Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were used to evaluate fuel clad fatigue limits. The evaluation of the fatigue limit assumes conservative load follow scenarios over the life of the fuel rod. Analysis of the representative rod power histories at the SPU conditions resulted in an increase in the clad fatigue levels. The combinations of long cycle lengths, high burnups, and the presence of cut pin penalties proved clad fatigue to be more limiting than previous reload designs. The clad fatigue criterion can be met under SPU core conditions with a maximum vessel average temperature of 572.0°F by appropriate cycle-specific core design.

7.4.2.4 Clad Stress and Strain Design Basis

The fuel system will not be damaged due to excessive fuel clad stress and strain.

Acceptance Limit

The volume-average effective stress calculated with the Von Mises equation, considering interference due to uniform cylindrical fuel pellet-clad contact, caused by fuel pellet thermal expansion, fuel pellet swelling, uniform fuel clad creep, and pressure differences, was less than the 0.2-percent offset yield stress with due consideration to temperature and irradiation effects under Condition II events. The acceptance limit for fuel rod clad strain during Condition II events is that the total tensile strain increase, due to uniform cylindrical fuel pellet thermal expansion during a transient, is less than 1 percent of the pre-transient value.

Design Evaluation

The Westinghouse PAD 4.0 fuel performance models (References 3 and 4) were used to evaluate fuel clad stress and strain limits. The local power duty during Condition II events was a key factor in evaluating the margin to fuel clad stress and strain limits. The fuel duty at the SPU conditions was more limiting, resulting in an increase in the cladding stress and strain levels. However, the fuel analyses results showed that the core power uprating will not affect the fuel's capability to meet the clad stress and strain limits.

7.4.3 Cycle-Specific Analyses

The fuel rod design criteria most affected by a change in core power rating have been evaluated. The evaluations indicated that all fuel rod design criteria can be met at the SPU core conditions with the proper cycle-specific core design.

Cycle-specific core designs and fuel performance analyses are performed for each reload cycle. These cycle-specific analyses are performed to ensure that all fuel rod design criteria will be satisfied for the specific operating conditions of that cycle.

Although the SPU analyses described in this section were performed for ZIRLO-clad fuel, the cycle-specific fuel performance analyses considered each specific fuel region (whether ZIRLO-clad fuel design or older fuel designs with different fuel features) in the core during that cycle. These analyses ensure that all fuel rod design criteria are met for each fuel region.

The cycle-specific fuel performance analyses considered any improved fuel performance models and methods licensed and approved by the NRC available at the time of the specific cycle design. These cycle-specific evaluations support the reload safety evaluation (RSE) performed for each cycle of operation.

7.4.4 Conclusions

The fuel rod design criteria most affected by a change in core power rating have been analyzed. The results indicate that all fuel rod design criteria can be met at the SPU core conditions with the proper cycle-specific core design.

7.4.5 References

1. WCAP-11596-P-A, *Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores*, T. Q. Nguyen et al., June 1988.

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

3. WCAP-15063-P-A, *Westinghouse Improved Performance Analysis and Design Model (PAD 4.0)*, Foster, Sidener, and Slagle, Rev. 1 with Errata, July 2000.

4. WCAP-12610-P-A, *VANTAGE+ Fuel Assembly Reference Core Report*, S. L. Davidson and T. L. Ryan, April 1995.

7.5 Neutron Fluence

7.5.1 Introduction

In the assessment of the state of embrittlement of light water reactor (LWR) pressure vessels, an accurate evaluation of the neutron exposure of the materials comprising the beltline region of the vessel is required. This exposure evaluation must, in general, include assessments not only at locations of maximum exposure at the inner radius of the vessel, but also as a function of axial, azimuthal, and radial location throughout the vessel wall.

In order to satisfy the requirements of 10CFR50, Appendix G (Reference 1), for the calculation of pressure/temperature limit curves for normal heatup and cooldown of the Reactor Coolant System (RCS), fast neutron exposure levels must be defined at depths within the vessel wall equal to 25 and 75 percent of the wall thickness for each of the materials comprising the beltline region. These locations are commonly referred to as the 1/4t and 3/4t positions in the vessel wall. The 1/4t exposure levels are also used in the determination of upper shelf fracture toughness as specified in 10CFR50, Appendix G. In the determination of values of reference temperature – pressurized thermal shock (RT_{PTS}) for comparison with the applicable PTS screening criterion as defined in 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events*, (Reference 2) maximum neutron exposure levels experienced by each of the beltline materials are required. These maximum levels occur at the vessel inner radius.

The methodology used to determine the fast neutron (E > 1.0 MeV) exposure of the IP3 pressure vessel derives from the guidance provided in ASTM Standard E853, *Analysis and Interpretation of Light Water Reactor Surveillance Results*, and Regulatory Guide (RG) 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, March 2001 (Reference 3). The analytical methodology has received regulatory approval as documented in WCAP-14040-NP-A, *Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves*, January 1996 (Reference 4). The Westinghouse methodology has also been documented in WCAP-15557, Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology, August 2000 (Reference 5).

7.5.2 Description of Analysis/Evaluation and Input Assumptions

A three-dimensional (3-D) assessment of fast neutron exposures for the IP3 reactor geometry was made using discrete ordinates transport techniques. The analysis was based on a two-dimensional/one-dimensional (2D/1D) synthesis of neutron fluxes that were obtained from a series of plant- and cycle-specific forward transport calculations using r-θ, r-z, and r spatial mesh. These transport calculations were subsequently compared against dosimetry results obtained from the in-vessel surveillance capsules withdrawn to date at IP3 in order to demonstrate that the plant-specific analysis meets the 20-percent uncertainty criterion specified in RG 1.190; however, these comparisons only serve to validate the calculational model and are not used in any way to modify the calculational results.

The generalized equation that was used to assess the fast neutron flux in the reactor pressure vessel, which is described in RG 1.190, is given as:

$$\phi_g(r,\theta,z)=\phi_g(r,\theta)\times\frac{\phi_g(r,z)}{\phi_g(r)}$$

where

$\phi_g(r,\theta)$ = The group g transport solution in r,θ geometry for a representative axial plane, that is, at the core midplane.

$\phi_g(r)$ and $\phi_g(r,z)$ = The 1-D and 2-D group g flux solutions whose ratio is used to determine a group-dependent axial shape factor.

The fast neutron exposure calculations were carried out using the DORT (DOORS 3.1 code package, Reference 6) discrete ordinates transport code in the forward mode and the BUGLE-96 cross-section library (Reference 7). This suite of codes has been used to support numerous pressure vessel fluence evaluations and are generally accepted by the Nuclear Regulatory Commission (NRC) for deterministic particle transport calculations, for example, neutron exposure and gamma-ray heating rate evaluations. All calculations were based on an S16 order of angular quadrature and a P5 expansion of the scattering cross-sections.

The core power distributions used in the plant-specific analysis were taken from the nuclear design reports for each of the first 13 operating fuel cycles at IP3. For future projections that support the IP3 stretch power uprate (SPU), core power distributions obtained from Westinghouse Core Engineering fuel management studies for Cycles 14 through 16 were used. The fast neutron transport calculations also account for several changes in core power during plant life. Specifically, reactor power increases from 3025 to 3067.4 MWt near the middle of

Cycle 12 and to 3216 MWt at the onset of Cycle 14, were assumed. Future projections beyond the end of Cycle 16 were based on the equilibrium cycle design intended for implementation in Cycle 16 core power distributions.

7.5.3 Acceptance Criteria

There are no specific acceptance criteria for this section. Adequacy of the modeling is tested by comparing the calculated results against dosimetry measurements from surveillance capsules withdrawn from the plant. As long as these comparisons fall within the ± 20-percent criterion specified in RG 1.190, the calculational results are validated, that is, no specific acceptance criteria apply to the calculated values. However, these calculated results are used as input to reactor vessel analysis that is described in subsection 5.1.2 of this report.

7.5.4 Results and Conclusions

Comparisons of the measurement results from the in-vessel surveillance capsules withdrawn from the IP3 reactor versus the corresponding calculated predictions obtained at the measurement locations are presented in Table 7.5-1 for the fast neutron sensor reactions. An examination of the measurement/calculation (m/c) ratios of the fast neutron sensor reaction rates obtained from the surveillance capsule irradiations shows consistent behavior for all reactions at all capsule locations within the constraint of the allowable ± 20-percent (1σ) uncertainty in the final calculated results. Specifically, Table 7.5-1 shows that the average M/C ratios range from 1.02 to 1.20 for the individual capsules and that the overall average M/C ratio for the entire 10 foil data set is 1.08 with an associated sample standard deviation of 9.6 percent. Therefore, these comparisons of calculations with the surveillance capsule dosimetry sets withdrawn to date validate the neutron transport calculations performed to support this program and demonstrate that the uncertainty criterion of ± 20 percent (1σ), as specified by RG 1.190, has been satisfied for the IP3 reactor.

Therefore, based on this validation, the maximum calculated fast neutron fluence and displacement of atom (dpa) exposure values for the IP3 pressure vessel are provided in Table 7.5-2. As presented, these data represent the maximum exposure of the pressure vessel clad/base metal interface at azimuthal angles of 0, 15, 30, and 45 degrees relative to the core cardinal axes. The data tabulation includes the plant-specific calculated fluence at the end of Cycle 12 (EOC 12, the last cycle completed at IP3), the end of Cycle 13 (EOC 13, which is the current operating fuel cycle), and projections for future operation to 23 (EOC 16), 32, 34 and 48 effective full-power years (EFPYs).

Based on the current NRC position of using the calculated values of neutron fluence to specify the neutron exposure for use in materials damage correlations, the calculated exposure values provided in Table 7.5-2 were provided for use in the materials properties assessments of the IP3 pressure vessel at SPU power conditions (see subsection 5.1.2).

7.5.5 References

1. 10CFR50, Appendix G, *Fracture Toughness Requirements.*

2. 10CFR50.61, *Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events, Federal Register*, Volume 60, No. 243, December 19, 1995.

3. Regulatory Guide 1.190, *Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence*, March 2001.

4. WCAP-14040-NP-A, *Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves*, January 1996.

5. WCAP-15557, *Qualification of the Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology*, August 2000

6. RSICC Computer Code Collection CCC-650, *DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System*, August 1996.

7. RSIC Data Library Collection DLC-185, *BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications*, March 1996.

Table 7.5-1

Comparison of Measured and Calculated Sensor Reaction Rate Ratios for the Fast Neutron Threshold Foil Reactions Obtained from In-Vessel Capsules Removed from Service at IP3

Capsule	M/C Ratio				Average	% Std. Dev.
	$^{63}Cu(n,\alpha)^{60}Co$	$^{54}Fe(n,p)^{54}Mn$	$^{58}Ni(n,p)^{58}Co$	$^{238}U(n,f)^{137}Cs$		
T	1.21	1.23	1.16	---	1.20	3.0
Y	1.10	1.01	0.98	1.09	1.05	5.7
Z	1.13	1.01	0.91	---	1.02	10.8
Average	1.15	1.08	1.02	1.09	**1.08**	**9.6**
% Std. Dev.	5.0	11.7	12.7	N/A		

Note:
The average and percent standard deviation values in boldface type represent the entire 10 sample threshold foil data set.

Table 7.5-2

Summary of Calculated Maximum Pressure Vessel Exposure at the Clad/Base Metal Interface for IP3

Cumulative Operating Time (EFPY)	Neutron Fluence (n/cm^2) (E > 1.0 MeV)			
	0.0 Degrees	15.0 Degrees	30.0 Degrees	45.0 Degrees
15.5 (EOC 12)	2.64e+18	4.01e+18	4.42e+18	5.86e+18
17.4 (EOC 13)	2.87e+18	4.38e+18	4.82e+18	6.30e+18
23.0 (EOC 16)	3.66e+18	5.58e+18	6.17e+18	7.98e+18
32.0	4.95e+18	7.57e+18	8.38e+18	1.07e+19
34.0	5.24e+18	8.01e+18	8.87e+18	1.13e+19
48.0	7.27e+18	1.11e+19	1.24e+19	1.56e+19
	Iron Atom Displacements (dpa)			
15.5 (EOC 12)	4.27e-03	6.42e-03	7.13e-03	9.48e-03
17.4 (EOC 13)	4.65e-03	7.00e-03	7.76e-03	1.02e-02
23.0 (EOC 16)	5.93e-03	8.93e-03	9.93e-03	1.29e-02
32.0	8.02e-03	1.21e-02	1.35e-02	1.73e-02
34.0	8.49e-03	1.28e-02	1.43e-02	1.83e-02
48.0	1.18e-02	1.78e-02	1.99e-02	2.51e-02

7.6 Reactor Internals Heat Generation Rates

7.6.1 Introduction

The presence of radiation-induced heat generation in reactor internals components, in conjunction with the various reactor coolant fluid temperatures, results in thermal gradients within and between the components. These thermal gradients cause thermal stress and thermal growth, which must be considered in the design and analysis of the various components. The primary design considerations are to insure that thermal growth is consistent with the functional requirements of the components, and to insure that the applicable ASME Code requirements are satisfied as part of the components evaluation that is described in Section 5.2 of this report. In order to satisfy these requirements, the reactor internals must be analyzed with respect to fatigue and maximum allowable stress considerations.

The reactor internals components subjected to significant radiation-induced heat generation are the upper and lower core plates, lower core support, core baffle plates, former plates, core barrel, thermal shield, baffle-former bolts and barrel-former bolts. However, due to relatively low heat generation rates in the lower core support and the thermal shield, these components experience little, if any, temperature rise relative to the surrounding reactor coolant.

This section provides a description of the methodology that was used to determine the radiation-induced heat generation rates for the axial core components (the upper and lower core plates) and selected radial reactor internals components (the core baffle plates, core barrel and thermal shield) due to the core power uprate to 3216 MWt. Although design-basis neutron exposure data for the reactor internals components are documented in WCAP-9620, Revision 1 (Reference 1), key core power distribution, fuel product, and methodology differences presently exist such that the axial component data reported in WCAP-9620 are non-conservative. However, as demonstrated in the Indian Point Unit 3 (IP3) plant-specific analysis performed to support the stretch power uprate (SPU), the radial component data from WCAP-9620 remains conservative. Key axial components for the IP3 SPU were addressed using recently developed baseline upper and lower core plate heating rates applicable to IP3 (that is, four-loop design with 2-inch thick core plates).

7.6.2 Key Input Assumptions

For the core plates, baseline gamma heating rates were determined for both long- and short-term conditions since the WCAP-9620 (Reference 1) data was no longer deemed applicable for the reactor internals design calculations of these components. Long-term heat generation rates intended to represent time-averaged behavior are used in component fatigue analyses, whereas the short-term results are intended to provide conservative values for use in

calculating maximum temperatures and thermal stresses of components. For the long-term heat generation rate evaluation of the core plates, a reactor power level of 3950 MWt was used in conjunction with a flat axial core power distribution, since these parameters significantly influence the core plate gamma heating rates and the aforementioned conditions conservatively bound the IP3 SPU. (Note: The reactor power level of 3950 MWt was selected since this currently bounds the entire fleet of Westinghouse four-loop plants.) For the short-term heat generation rate evaluation of the upper core plate, the reactor power of 3950 MWt was assumed and a conservative design-basis top-peaked axial power distribution from WCAP-9620 (Reference 1) was used. Analogous conditions were applied in the short-term heating rate evaluation of the lower core plate; however, in this case, the design basis bottom-peaked axial power distribution from Reference 1 was employed for conservatism.

For the radial reactor internals components, only a long-term analysis was performed, since it was anticipated that the current IP3 gamma heating rates would be bounded by the corresponding data reported in WCAP-9620. (This scenario was hypothesized since IP3 has transitioned to low-leakage loading patterns, whereas an out-in loading pattern was assumed in WCAP-9620 (Reference 1). Hence, the long-term case was examined to provide confirmation that the WCAP results remained conservative for the radial components.) Since the long-term radial case of WCAP-9620 was shown to be bounding, the short-term radial case of WCAP-9620 would also remain bounding and, therefore, was not calculated. The long-term heat generation rate evaluation of the core baffle plates, core barrel, and thermal shield was based on the Cycle 13 radial power distribution forecasted for use by IP3 operating at the reactor power level of 3216 MWt, as reported in Table 2.1-2.

Design basis heat generation rates applicable to the IP3 radial internals were obtained from Appendix J of WCAP-9620 (Reference 1). The core power distributions upon which those calculations were based were derived from statistical studies of 23 independent fuel cycles from 10 four-loop reactors. These power distributions represented an upper tolerance limit for beginning-of-cycle (BOC) and end-of-cycle (EOC) power in the peripheral fuel assemblies, based on a 95-percent probability with a 95-percent confidence level. Most of the evaluated fuel cycles were based on an out-in fuel loading strategy (fresh fuel on the periphery) which, when combined with the statistical processing of the data, resulted in a design basis core power distribution that tended to be biased high on the periphery. This high bias on the core periphery was desired by the reactor internals analysts to ensure conservative, but realistic, design calculations for the critical baffle-barrel region of the reactor internals and explains why the WCAP-9620 radial component heating rate results were expected to bound the corresponding IP3 values.

7.6.3 Acceptance Criteria

There are no specific acceptance criteria since this is an input to the reactor internals evaluation that is described in Section 5.2 of this report.

7.6.4 Description of Analysis/Evaluation and Results

The heat generation rate analyses were carried out using the DORT (DOORS 3.1 code package [Reference 2]) two-dimensional (2-D) discrete ordinates transport code in the forward mode and the BUGLE-96 cross-section library (Reference 3). This suite of codes has been used to support numerous pressure vessel fluence evaluations and are generally accepted by the Nuclear Regulatory Commission (NRC) for deterministic particle transport calculations, for example, neutron exposure and gamma-ray heating rate evaluations.

Two different coordinate systems were used in the 2-D heating rate analyses to precisely model the components undergoing evaluation. The core baffle plates were analyzed using a x,y coordinate system, and the core barrel and thermal shield heating rates were determined using a r,θ geometric model.

The results of the radiation-induced heat generation rate calculations were provided as inputs for the reactor internals evaluations described in Section 5.2. The volume-averaged heat generation rates for the core plates and radial reactor internal components that were evaluated as part of this study are summarized in Table 7.6-1. In accordance with WCAP-9620 (Reference 1), this table also segregates the core plate heating rates into two distinct regions. Region A refers to the cylindrical portion of the core plates that are axially adjacent to the active fuel, and Region B refers to the annular portion of the plates that are located radially outboard of the active fuel.

As expected, the revised IP3 zone average gamma heating rates for the core plates tended to be much higher than the corresponding WCAP-9620 (Reference 1) data. As a result, the spatial distributions of long-term and short-term heating rates for the upper and lower core plates that are presented in Tables 7.6-2 through 7.6-5 were also identified for consideration as part of the component evaluation that is described in Section 5.2 of this report.

Table 7.6-1 also shows that the current IP3 zone average gamma heating rates for the core baffle, core barrel, and thermal shield continue to remain bounded by the conservative radial component heating rates that are reported in WCAP-9620 (Reference 1).

7.6.5 References

1. WCAP-9620, *Reactor Internals Heat Generation Rates and Neutron Fluences*, Rev. 1, A. H. Fero, December 1983.

2. RSICC Computer Code Collection CCC-650, *DOORS 3.1, One-, Two-, and Three-Dimensional Discrete Ordinates Neutron/Photon Transport Code System*, August 1996.

3. RSIC Data Library Collection DLC-185, *BUGLE-96, Coupled 47 Neutron, 20 Gamma-Ray Group Cross Section Library Derived from ENDF/B-VI for LWR Shielding and Pressure Vessel Dosimetry Applications*, March 1996.

Table 7.6-1 Reactor Internals Zone Average Gamma Heating Rates		
	Region Average Long-Term Heating Rates (Btu/hr-lbm)	
Location	WCAP-9620-R1 Analysis* (Ref. 1, Appendix J)	New IP3 Analysis
Baffle Plate 18	784	438
Baffle Plate 19	885	526
Baffle Plate 20	821	403
Baffle Plate 21	645	255
Core Barrel	158	76
Thermal Shield	22	11
* Values are scaled down by a factor of 3216/3565 to account for difference in reactor power.		
	Upper and Lower Core Plates Heating Rates (Btu/hr-lbm)	
	WCAP-9620-R1 Analysis (Ref. 1, Appendix E&J)(1)	New Baseline Analysis(2)
Long-Term Heating Rates		
Upper Core Plate A	27.4	246
Upper Core Plate B	5.57	29
Lower Core Plate A	249	903
Lower Core Plate B	52.4	88
Short-Term Heating Rates		
Upper Core Plate A	64.4	265
Upper Core Plate B	15.0	34
Lower Core Plate A	822	1480
Lower Core Plate B	201	167

Note:

1. Based upon 3565 MWt
2. Based upon 3950 MWt

Table 7.6-2

Spatial Distribution of Long-Term Gamma Heating Rates (Btu/hr-lbm) in the Upper Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	472	426	335	269	219	194
2.95	471	425	334	268	218	194
4.92	470	425	333	267	217	193
6.89	469	423	332	266	217	192
8.86	467	422	331	265	216	192
10.83	466	420	330	264	215	191
12.80	464	419	329	263	215	190
14.76	463	418	328	262	214	190
16.73	462	417	327	262	213	189
18.70	461	416	326	261	213	189
20.67	460	415	325	261	213	189
22.64	459	415	325	260	213	189
24.61	459	415	325	261	213	189
26.57	459	415	325	261	213	189
28.54	459	415	326	261	213	189
30.51	459	415	326	261	213	189
32.48	459	415	325	261	213	189
34.45	458	414	325	260	212	188
36.42	457	412	324	259	211	188
38.39	454	410	322	258	210	186
40.35	449	406	319	255	208	184
42.32	443	400	314	252	205	182
44.29	435	393	309	247	201	178
46.26	424	383	301	241	196	174
48.23	409	369	290	232	189	167
50.20	390	352	277	221	180	160
52.17	366	331	260	208	169	150
54.13	338	306	240	192	156	139
56.10	307	277	218	174	142	126
58.07	273	247	194	155	127	112
60.04	239	216	169	136	110	98
62.01	204	184	144	116	94	83
63.78	172	155	122	97	79	70
64.96	150	135	106	84	69	61
65.65	134	121	95	75	61	54
66.15	121	109	86	68	56	49
66.64	90	82	66	53	44	39
67.20	63	58	48	40	33	30
67.89	54	48	37	30	25	23
68.70	53	46	31	24	20	18
69.52	52	45	29	21	17	15
70.33	50	43	27	19	15	13
71.15	47	40	25	17	13	11
71.96	44	37	23	16	12	10
72.78	39	33	21	14	11	9
73.59	35	29	18	12	9	8
74.00	32	27	17	11	8	7

Table 7.6-3

Spatial Distribution of Short-Term Gamma Heating Rates (Btu/hr-lbm) in the Upper Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	517	467	367	295	241	213
2.95	517	466	366	293	240	213
4.92	516	466	365	292	239	212
6.89	514	464	364	291	238	211
8.86	513	463	363	290	237	211
10.83	512	462	362	290	237	210
12.80	510	460	361	289	236	209
14.76	509	459	360	288	235	209
16.73	507	458	359	287	235	208
18.70	506	457	358	287	234	208
20.67	505	456	357	286	234	208
22.64	504	455	357	286	234	208
24.61	504	455	357	286	234	208
26.57	504	455	357	286	234	208
28.54	504	455	357	286	234	208
30.51	504	455	357	286	234	208
32.48	503	454	357	286	233	207
34.45	502	453	356	285	233	207
36.42	500	451	354	284	232	206
38.39	497	448	352	282	230	204
40.35	492	444	348	279	228	202
42.32	485	438	344	275	225	199
44.29	475	429	337	270	220	195
46.26	463	418	328	263	214	190
48.23	446	403	316	253	206	183
50.20	425	384	301	241	197	174
52.17	399	360	283	226	185	164
54.13	369	333	261	209	171	151
56.10	335	302	237	190	155	138
58.07	298	269	212	170	138	123
60.04	261	235	185	148	121	107
62.01	223	201	158	126	103	91
63.78	188	169	133	106	87	77
64.96	163	147	116	92	75	67
65.65	146	131	103	82	67	59
66.15	131	118	93	75	61	54
66.64	99	90	73	59	49	43
67.20	70	65	54	44	37	34
67.89	62	55	42	34	29	26
68.70	61	53	36	28	23	21
69.52	61	52	34	24	20	17
70.33	59	50	32	23	18	15
71.15	56	48	30	21	16	14
71.96	52	44	28	19	15	12
72.78	47	40	25	17	13	11
73.59	42	35	22	15	11	10
74.00	39	33	21	14	11	9

Table 7.6-4

Spatial Distribution of Long-Term Gamma Heating Rates (Btu/hr-lbm) in the Lower Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	694	782	958	1196	1518	1679
2.95	693	780	956	1196	1522	1684
4.92	693	781	956	1197	1524	1687
6.89	690	778	953	1193	1519	1683
8.86	686	773	946	1185	1507	1668
10.83	680	766	939	1174	1493	1652
12.80	676	761	932	1165	1482	1641
14.76	672	757	927	1159	1474	1631
16.73	670	755	924	1156	1470	1628
18.70	669	753	922	1153	1467	1624
20.67	667	751	919	1150	1463	1619
22.64	665	749	916	1146	1458	1613
24.61	665	748	915	1144	1455	1611
26.57	667	750	918	1148	1460	1616
28.54	670	755	924	1157	1471	1628
30.51	675	760	932	1166	1484	1642
32.48	677	764	936	1173	1492	1651
34.45	678	765	937	1174	1493	1653
36.42	678	764	936	1172	1491	1650
38.39	677	763	935	1171	1490	1649
40.35	678	764	937	1172	1492	1652
42.32	679	766	941	1178	1500	1660
44.29	681	769	945	1185	1508	1670
46.26	679	768	946	1187	1511	1674
48.23	670	759	937	1177	1499	1660
50.20	650	737	912	1146	1460	1617
52.17	616	700	866	1090	1388	1537
54.13	567	644	798	1004	1279	1417
56.10	505	573	708	890	1134	1256
58.07	434	491	604	758	965	1068
60.04	359	405	496	621	788	872
62.01	286	321	391	488	618	683
63.78	224	251	304	377	476	525
64.96	186	207	249	308	386	425
65.65	163	180	216	266	331	363
66.15	144	160	191	236	292	320
66.64	120	133	158	197	253	280
67.20	98	107	127	161	216	244
67.89	79	87	103	134	185	211
68.70	64	71	84	111	157	180
69.52	54	59	70	93	135	156
70.33	45	49	58	79	117	136
71.15	38	42	49	67	102	120
71.96	32	35	42	58	89	105
72.78	26	29	35	49	76	90
73.59	22	24	28	40	64	76
74.00	19	21	25	36	58	69

Table 7.6-5

Spatial Distribution of Short-Term Gamma Heating Rates (Btu/hr-lbm) in the Lower Core Plate for IP3

Radial Mesh Midpoint (inches)	Bottom Surface 0.00	Distance through Plate (inches) 0.25	0.75	1.25	1.75	Top Surface 2.00
0.98	1178	1313	1584	1956	2457	2708
2.95	1174	1310	1581	1957	2464	2717
4.92	1175	1310	1581	1958	2465	2719
6.89	1171	1306	1576	1951	2458	2711
8.86	1163	1297	1565	1938	2440	2690
10.83	1154	1287	1553	1922	2418	2666
12.80	1148	1279	1542	1908	2401	2648
14.76	1142	1273	1534	1898	2388	2633
16.73	1138	1268	1530	1893	2382	2627
18.70	1135	1265	1526	1888	2376	2620
20.67	1132	1262	1522	1883	2370	2613
22.64	1130	1259	1517	1877	2362	2605
24.61	1129	1258	1516	1875	2360	2602
26.57	1133	1262	1521	1881	2367	2610
28.54	1138	1269	1531	1894	2383	2628
30.51	1145	1277	1541	1908	2402	2649
32.48	1149	1282	1549	1918	2414	2662
34.45	1150	1284	1550	1920	2417	2665
36.42	1150	1283	1549	1918	2415	2663
38.39	1149	1282	1548	1917	2414	2662
40.35	1149	1283	1550	1919	2417	2666
42.32	1151	1286	1555	1927	2428	2678
44.29	1151	1288	1561	1935	2439	2690
46.26	1145	1283	1559	1935	2439	2691
48.23	1128	1265	1541	1915	2414	2664
50.20	1092	1227	1497	1863	2348	2591
52.17	1035	1163	1421	1769	2230	2461
54.13	953	1071	1308	1629	2054	2267
56.10	850	954	1162	1446	1824	2012
58.07	732	820	995	1235	1557	1717
60.04	609	680	822	1016	1277	1408
62.01	488	543	652	805	1009	1111
63.78	387	428	511	627	783	861
64.96	324	357	423	517	641	703
65.65	285	313	370	450	554	606
66.15	253	279	330	403	493	539
66.64	214	235	277	342	432	478
67.20	177	193	226	285	377	423
67.89	146	160	188	243	332	376
68.70	122	134	158	208	290	331
69.52	104	114	136	181	257	295
70.33	89	98	117	158	229	265
71.15	76	84	101	138	204	236
71.96	64	72	87	119	179	209
72.78	54	61	73	102	155	181
73.59	45	50	60	83	129	152
74.00	40	44	53	74	116	138

8.0 TURBINE ISLAND ANALYSIS

8.1 Steam Turbine

The currently installed Indian Point Unit 3 (IP3) steam turbine consists of a combination of a Siemens-Westinghouse nuclear turbine generator set and Brown Boveri (Alstom) equipment. The steam turbine is composed of four elements—one double-flow high-pressure (HP) turbine BB96 and three Brown Boveri (Alstom) double-flow, low-pressure (LP) turbines.

In order to optimize the HP efficiency and make it compatible with the higher mass flow at the Stretch Power Uprate (SPU) thermal power, the rotor, including blading and the inner casing of the HP turbine will be exchanged. The existing turbine valves and auxiliary systems were found to be acceptable for the full-power uprate pressure, temperature, and flow conditions. The new HP turbine components were designed so as to not exceed the LP turbine inlet flow and pressure conditions.

The HP turbine will be replaced by the full-arc steam admission turbine during an upcoming refueling outage. This all-reaction turbine is designed to provide 2-percent nominal flow margin at the full-uprate power level throttle valve steam conditions. This design also provides improved full-load performance by eliminating the partial admission control stage and applying current blade path technology.

The major changes associated with the new HP turbines are:

- Elimination of the inlet nozzle blocks that will be replaced with full-arc admission and a new inner casing including a diagonal stage.
- Optimized all-reaction blading
- Improved materials for blade rings (stainless steel)
- Monoblock HP rotor with no through-bore
- Full-arc steam admission at all loads

The existing turbine bearings, gland seals, main lube oil system, hydraulic control system, and gland sealing steam system are acceptable for the uprated conditions. The HP turbine first-stage instrumentation will be adjusted to the new pressure conditions for the reaction turbine.

The BB96 HP turbine retrofit for IP3 was evaluated for the likelihood of missile generation due to HP rotor burst. The study evaluated the likelihood of missile generation resulting from a burst of a fully integral nuclear HP rotor. Three potential failure mechanisms were considered:

- Ductile burst due to overspeed.
- Fracture resulting from high-cycle fatigue cracking.
- Fracture resulting from low-cycle fatigue cracking.

A ductile failure analysis showed that a ductile burst will not occur until the speed of the rotor is increased to greater than 240 percent of rated speed; this is well beyond the design overspeed. A fatigue evaluation showed that the minimum safety factor for the newly designed BB96 HP rotor is two times the safety factor of the original rotor at the limiting location. Since there is no history of high-cycle fatigue issues with the existing HP turbines, the risk of missile generation from this mechanism is negligible. In the case of low cycle fatigue, the failure mechanism is brittle fracture. A calculation of cyclic life assuming a threshold internal flaw at the highest stressed section based on ultrasonic testing (UT) inspection sensitivity showed that the rotor low cycle fatigue life is greater than 10,000 start cycles. Based on the results of this study, there is not a significant likelihood of missile generation for the BB96 HP retrofit.

The LP turbine components were originally dimensioned for 105 percent steam flow. This applies to LP blading, inner casing, and rotors with couplings. These components can therefore be operated at a 5 percent higher steam flow rate; 9900 klb/hr at an LP inlet pressure of 203 psia. The Phase 1 SPU steam conditions remain within the LP turbine original design conditions and were found to have no effect on the validity of the existing turbine missile analyses.

8.1.1 Overspeed

The construction of IP3 predates the use of Intercept valves in nuclear plants, therefore, it uses a LP Steam Dump System for overspeed protection. The current WR^2 of IP3 with BB96-(3) Brown Boveri LP turbines and the generator rotor is 10,163,468 lb-ft^2. The new HP rotor will be approximately 20 percent heavier than the original HP rotor. This will increase the WR^2 approximately 5 percent and the LP dump system will remain acceptable at the SPU conditions because the higher WR^2 requires more steam to spin up the turbine to higher speeds and is, therefore, conservative with respect to the capability of the LP Steam Dump System to provide overspeed protection.

8.1.2 Conclusions

The turbines, turbine valves, and auxiliary systems were found to be acceptable for the Phase 1 full-power SPU pressure, temperature, and flow conditions. The turbine bearings, gland seals, main lube oil system, hydraulic control system, and gland sealing steam system are acceptable for the Phase 1 SPU conditions. The Phase 1 SPU steam conditions were found to have no effect on the validity of the existing turbine missile analyses. Since the Phase 2 modifications to the LP turbines will maintain the design basis for the turbine missile analysis, this analysis will continue to be acceptable at 3216 MWt.

8.2 Heat Balances

Heat balances were generated to identify relevant parameters and design inputs to evaluate balance-of-plant (BOP) systems, structures and auxiliaries at the SPU conditions. Detailed heat balance models were developed and tuned to match plant operational data and extrapolated to SPU conditions. In addition to the guarantee heat balance at full-load conditions at rated condenser pressure, heat balances were also generated for partial-load conditions and for different condenser pressure levels.

These heat balances were used in the BOP evaluations as indicated in Section 9 of this report.

9.0 BOP SYSTEMS

Introduction

To predict the performance of the balance-of-plant (BOP) thermal cycle at the stretch power uprate (SPU) conditions and to determine the corresponding system and equipment operating parameters, heat balances were developed using the PEPSE models.

The SPU heat balances define the bounding parameters for evaluating the BOP system performance at the SPU condition.

Method of SPU Heat Balance Development

To accurately predict BOP system performance during SPU operation, it was first necessary to develop a benchmark heat balance model that represented the current plant performance. This benchmark heat balance model was then used as a basis for developing a variety of SPU cases.

The development of the baseline and SPU models was accomplished as follows:

- The existing PEPSE heat balance model that was based on "as-designed" component parameters was reviewed. Physical data in the model were verified as being representative of the current plant design by a detailed review of plant design documents and physical inspection results.

- Actual operating temperatures, pressures, and flows with the plant operating at 100-percent power were obtained. Using these data, the PEPSE model was tuned to represent the actual performance characteristics of the plant thermal cycle, including the effects of component degradation or modifications that may change their performance from the as-designed characteristics. This tuned heat balance was then established as the "benchmark heat balance."

- The two sets of SPU heat balance were then run for a range of condenser backpressures (that is, circulating water temperature variations). The first set provided data for an uprate power level of 3168 MWt core power to represent Phase 1 conditions. A 0.5-percent margin was added to each case to provide conservatism. The second set provided data for an uprate power level of 3216 MWt core power to reflect the future thermal power at SPU conditions with an additional 0.5-percent margin for each case to provide conservatism. The BOP plant systems were evaluated to 3216-MWt core power unless otherwise noted.

9.1 Main Steam System

9.1.1 Introduction

Main Steam System (MSS) piping components and equipment, including the main steam safety valves (MSSVs), atmospheric relief valves (ARVs), main steam isolation valves (MSIVs), and condenser steam dump valves, were evaluated for the Indian Point Unit 3 (IP3) SPU conditions.

The MSS transports saturated steam produced in the steam generators to the main turbine for power generation. The steam dump and bypass piping and valves provide alternate flow paths for the generated steam when the turbine is unavailable, or when a plant operational transient requires a reduction in the main turbine power level.

In addition to supplying saturated steam to the main turbine, the MSS also supplies steam to the following users:

- Main boiler feed pump drive turbines
- Moisture separator reheaters (MSRs)
- High-pressure (HP) turbine
- HP turbine gland sealing steam system
- Priming and steam jet air ejectors
- Auxiliary feedwater (AFW) pump drive turbine
- Auxiliary steam system (via reducing valve)

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. 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 value has not changed for SPU.

9.1.2 Input Parameters and Assumptions

The evaluation of the MSS used conditions predicted by SPU thermal cycle heat balances. The SPU heat balances were developed by first establishing a benchmark heat balance model representative of current plant performance, which was then used as a basis for developing heat balances representative of SPU operation. The 3216 MWt SPU heat balance parameters were used as the bounding values for evaluating the MSS.

9.1.3 Description of Analysis and Evaluations

The MSS piping, valves, and components were evaluated to verify their ability to operate at SPU conditions. Based on SPU heat balances, operation at the higher SPU power level increases the steam flow required from the steam generators to the HP turbine. Additional steam flow is also necessary for other components, which operate at higher loads and use steam as a motive force.

The SPU heat balance parameters were reviewed and compared with original system heat balance parameters as well as the original component design parameters to determine their capability to function adequately at SPU conditions.

The following system design features were reviewed and evaluated:

- Main steam (MS) pressure drop and flow versus required HP turbine inlet conditions
- MS piping pressure/temperature design and flow velocities
- MS component pressure/temperature design
- Design closure time for MSIVs
- Setpoints for ARVs
- Setpoints for MSSVs
- Steam supply flow rates/line sizes/velocities to auxiliary components
- Accident analyses (see Section 6 of this report for the evaluations of specific accidents)

9.1.4 Acceptance Criteria

The following acceptance criteria must be met:

- Steam pressure and flow must satisfy HP turbine throttle inlet conditions required by the SPU heat balances.

- MS piping and component pressure and temperature design must exceed the maximum expected operating pressure and temperature associated with SPU and abnormal and accident conditions.

- MSIVs must be able to close within the required times under SPU conditions and abnormal and accident conditions.

- Increases in MS piping velocities due to the SPU will remain within accepted industry standards for the service conditions and existing pipe material. The current Flow-Accelerated Corrosion (FAC) Program will continue to require that the MS piping be monitored for any lines exceeding program criteria.

- The MSSV setpoints must consider the added piping pressure drop due to increased SPU flows and must be adequate to ensure that the steam generator pressure does not exceed 110 percent of design pressure.

- Sufficient steam flow and pressure must be provided to auxiliary components using MS to meet SPU operating requirements for each component.

9.1.5 Design Criteria

The MSS was designed to meet the intent of the General Design Criteria (GDC), which was published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the MSS to meet these requirements. Therefore the MSS continues to meet the criterion requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the MSS to meet these requirements. Therefore the MSS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the MSS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the MSS will continue to meet the criterion requirements.

Environmental qualification (EQ) of MSS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and DOR Guidelines (see LAR Section 11, and ER Section 10). The MSS is monitored as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 4). The MSS is designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG 0578 and 0737 (References 5 and 6) SPU operation does not affect the ability of the MSS to meet these requirements. The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. Therefore the MSS continues to meet the criterion requirements.

9.1.6 Results and Conclusions

Based on the system evaluation discussed in the previous sections, it was determined that the IP3 MSS is capable of performing its design function under SPU conditions. The following sections provide additional details of the evaluation results/conclusions.

9.1.6.1 Flow Restriction Nozzles

The MS header at the outlet of each steam generator contains a venturi-type steam flow restriction nozzle. These flow restriction nozzles are designed to limit the blowdown flow from a downstream rupture in the main steam header, and to provide flow measurement of each steam header via differential pressure connections upstream and downstream. In addition, the model 44F steam generators contain a flow restriction nozzle at the outlet of the steam generators. As described in Sections 4 and 5 of this report, the flow restriction nozzles are acceptable for use under SPU conditions.

9.1.6.2 Main Steam Safety Valves

Each of the four MS headers contains five MSSVs, located outside of the containment, which provide overpressure protection for the steam generators and the MSS inside containment. The safety valves are designed to pass a total of 100-percent of MS flow rate while maintaining the steam generators at or below 110-percent of design pressure. Maximum steam flow rate at 100-percent power under SPU conditions is significantly below the MSSV design capacity. As described in Sections 4 and 5 of this report, the IP3 MSSVs are acceptable for overpressure protection under SPU conditions.

Based on the aggregate capacity of the safety valves, the safety valve setpoints were evaluated to confirm that the existing setpoints do not result in a steam generator pressure greater than 110 percent of the design pressure of 1085 psig. There is no change to the steam generator design pressure due to the SPU. The evaluation determined that the steam generator pressure was well below the 110 percent limit when the existing safety valves were passing the required relieving capacity at SPU conditions.

MSSV setpoints are acceptable for operation under SPU conditions and will maintain the steam generators below their design pressure.

9.1.6.3 Atmospheric Steam Relief Valves

The MSS includes four ARVs. These relief valves are used for controlling Reactor Coolant System (RCS) temperature to maintain hot standby and to cool the RCS prior to initiating residual heat removal (RHR).

To limit the frequency of safety valve lifts, the setpoints of the ARVs are based on plant no-load conditions and the lowest MSSV setpoint. These four valves are designed to pass a total of 10 percent of full-load MS mass flow rate at no-load steam generator outlet pressure. As discussed in subsection 4.2.1 of this document, the IP3 ARVs are adequate to support required steam relief (during a steam generator tube rupture [SGTR] and other cooldown events) under SPU conditions.

Since the no-load steam generator pressure and the lowest set MSSV setpoint are not changed with the implementation of SPU, current setpoints of the ARVs are acceptable and will not change.

9.1.6.4 HP Steam Dump Valves

The HP steam dump valves and associated piping are designed to reduce the transients on the RCS during plant trips and load rejections. Twelve HP steam dump valves, six on each MS auxiliary loads header, are provided to discharge MS directly to the main condenser. The valves have a sizing criteria of a total of 40 percent of full-load MS mass flow at full load T_{avg} (see section 4.2).

The full-load MS flow increases under SPU conditions. As detailed in subsection 4.2.1 of this report, the HP steam dump valves are adequate for operation under SPU conditions.

9.1.6.5 Low-Pressure Steam Dump Valves

The low-pressure (LP) steam dump valves and associated piping are designed to preclude LP turbine overspeed by diverting a portion of the HP turbine exhaust steam from the crossunder lines directly to the main condensers. Six 10-inch diameter dump valves and piping are provided, each of which branches from the crossunder line near the MSR to the condenser. Each dump line contains a motor-operated isolation valve and an air-operated dump valve in series.

The LP steam dump valves are required to pass a total of approximately 25 percent of the MS available to limit overspeed of the turbine following a turbine or generator trip. The full-load MS flow increases under SPU conditions. As detailed in subsection 4.2.1, the IP3 LP steam dump valves are adequate for operation under SPU conditions.

9.1.6.6 MSIVs and Non-Return Valves

The IP3 MSIVs and non-return check valves are located outside of containment (downstream of the MSSVs) and function to prevent uncontrolled blowdown of more than one steam generator. The valves are swing-disc check valves. The isolation valves are reverse-mounted on the MS headers, utilizing a spring-loaded air piston to hold the disc out of the steam flow.

Since the steam generator design pressure and the MSSV setpoints are not changing due to SPU operation, the MSIV and non-return valve design pressure and temperature are not affected.

The MSIVs and non-return valves are required to have the capability of closing in 5 seconds or less in the event of a MS line rupture. Because the MSIVs isolation valves and non-return valves are a check-valve design, reverse steam flow will assist in closing the non-return valves. The MSIVs are reverse mounted check valves with the disk held out of the steam flow by an air operated piston and are assisted in closing by forward steam flow. Therefore under SPU conditions of increased flow, the valves will continue to meet their design capability, including the capability of closing in 5 seconds or less. The MSIVs and non-return valves are acceptable for SPU operation without modification. Piping and support loads relating to rapid valve closure are addressed in Section 9.9 of this report.

9.1.6.7 AFW Pump Drive Turbine Steam Supply

In the event of an abnormal condition and accident, the MSS must supply motive steam to the AFW pump drive turbine. The AFW pump can operate using MS over the entire range of MS pressures from normal operation to very low pressures at startup or shutdown.

The MS supply line of the turbine drive for the AFW pump is designed to provide steam at a range of pressures from 110 to 1118 psig. The turbine drive is designed to operate at a maximum inlet pressure of 600 psig. A pressure control valve on the steam supply line reduces the supply pressure to 600 psig or less. Based on the evaluation under SPU conditions at full load, the pressure of the MS supply upstream of the control valve was 740 psig, thus providing sufficient pressure.

9.1.6.8 Main Feedwater Pump Drive Turbine Steam Supply

The MSS supplies motive steam to the main feedwater pump turbine drives during all modes of pump operation. Initially, during plant startup, steam is provided directly from the MS headers. When sufficient pressure exists in the hot reheat side of the MSR, steam is provided from the "A" MSRs.

Since the full-load main feedwater flow requirements increase relative to SPU operation, the required steam flow for the two feedwater pump turbines also increases. A comparison of the required steam flow to the turbine drives during SPU operation with SPU heat balances confirmed adequate steam flow capacity available under SPU operation.

9.1.6.9 Main Steam Piping

Under SPU operating conditions, the steam generator steam outlet mass flow rate will increase approximately 6 percent above the current operating mass flow rate. This increase will impact MS header piping pressure drops and flow velocities.

The MS piping pressure and temperature design bounds SPU pressure temperature conditions. Piping pressure temperature design is, therefore, acceptable for SPU conditions.

The MS header piping pressure drop at SPU conditions from the steam generators to the HP turbine throttle valve inlet was calculated and compared with original design pressure drop parameters. There was adequate steam flow and pressure to satisfy throttle valve inlet requirements under SPU conditions.

Increased MS piping flow velocities based on SPU conditions in MS piping to normally operating components were evaluated and found acceptable. Velocities in pipelines to infrequently used lines, such as the AFW pump turbines and startup supply line for the main feedwater pump turbines, are also acceptable. Existing FAC monitoring activities will ensure that corrosion remains acceptable.

9.1.7 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.2 Extraction Steam System

9.2.1 Introduction

The IP3 Extraction Steam (ES) System was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The IP3 ES System is designed to transmit steam from high pressure (HP) and low pressure (LP) main turbines to the shell sides of the feedwater heaters to heat feedwater to improve cycle efficiency.

The ES System has no safety function.

9.2.2 Input Parameters and Assumptions

The ES was evaluated using conditions predicted by SPU thermal cycle heat balances. The SPU heat balances were developed by first establishing a benchmark heat balance model representative of current plant performance, which was then used as a basis for developing heat balances representative of SPU operation. The SPU heat balance parameters were used as the bounding values for evaluating the ES system.

9.2.3 Description of Analysis and Evaluations

The ES System was evaluated to verify its ability to operate at the SPU conditions. SPU heat balances were used to establish the SPU parameters with which the turbine cycle system evaluations were performed. A tuned baseline heat balance was also used in these evaluations.

The following ES System design features were reviewed and evaluated:

- The pressure and temperature design of extraction steam piping and valves was compared with SPU pressure and temperature conditions.
- The feedwater heater (FWH) shell pressure and temperature design was compared with SPU pressure and temperature conditions.

- The results of past FWH inspections were reviewed to determine the current physical condition of the heaters.

- Extraction steam piping velocities at the higher flow rates of SPU operating conditions were compared to industry standard criteria for extraction steam service. These velocities were also evaluated to determine whether the SPU flow rates increase the possibility of flow-accelerated corrosion (FAC).

- FWH extraction steam inlet nozzle velocities at SPU operating conditions were compared with standard industry guidelines (Heat Exchange Institute [HEI]) to size FWH nozzles to determine the potential for increased wear and FAC.

- The SPU extraction steam flow rates into the FWHs were evaluated to determine the effects on tube vibration and erosion of internal subcomponents and support structures.

- Extraction steam piping flow regimes were evaluated relative to moisture carryover (MCO) capability.

9.2.4 Acceptance Criteria

The evaluations must demonstrate that design parameters of the existing ES System piping and valves bound the corresponding parameters at SPU conditions. The following criteria must be met:

- The pressure and temperature design of extraction steam piping and valves should envelop the pressure and temperature conditions expected under SPU operation.

- FWH shell pressure and temperature design should envelop the pressure and temperature conditions expected under SPU operation.

- FWH extraction steam inlet nozzle velocities at SPU conditions should not appreciably increase the potential for wear and FAC.

- Extraction steam piping flow velocities due to SPU are within the industry standard values for extraction steam piping of this size, material, and service. The expected velocities at SPU flow rates, when considered with the SPU operating temperatures, should not appreciably increase the potential for FAC.

- FWH level control systems effectively control level without activating high level protection or otherwise adversely affecting thermal efficiency.

- The SPU extraction steam flow rates into the FWHs should not cause destructive tube vibration or the erosion of internal parts such that their function is impaired.

- Relative to extraction steam line flow regimes, system piping flow must exhibit effective MCO and should not exhibit slug flow characteristics.

9.2.5 Design Criteria

The IP3 ES System is designed to transmit steam from HP and LP main turbines to the shell sides of the feedwater heaters to heat feedwater to improve cycle efficiency. The ES System is not safety related. Criterion required to meet SPU conditions are listed in the Acceptance Criteria above.

9.2.6 Results and Conclusions

Based on the system evaluation as discussed in the above sections, it was determined that the IP3 ES System is capable of performing its design function under SPU conditions.

ES System pressure/temperature conditions predicted under SPU conditions are bounded by system component and piping design parameters.

Calculated pipeline velocities under SPU conditions are either bounded by industry standard velocity limits, or the lines are already included in the FAC program and are, therefore, acceptable for SPU operation. FAC associated with these lines under SPU conditions will not significantly increase. FAC Program activities for the extraction lines will be continued during SPU operation.

With the exception of IP3 FWHs 34A, B, and C shell-side temperature, the FWH shells pressure and temperature design envelops the SPU pressure/temperature conditions. For FWHs 34A, B, and C, the maximum shell-side inlet temperature during SPU exceeds the shell design temperature by 29°F. Since the shell material of these heaters is carbon steel SA 516 Grade 70, the shell design can accept the higher SPU temperatures as the maximum allowable stress value of material SA 516 Grade 70 in tension does not change in the temperature range of –20° to 650°F.

With the exception of IP3 FWHs 31A, B, and C and 32A, B, and C, extraction steam inlet nozzle velocities are bound by the HEI standard industry guidelines for FWH nozzles. Current operation of these heaters exceed HEI guidelines. The SPU will decrease the velocities of FWH 31A, B and C by approximately 3 fps, and increase the velocities of FWHs 32A, B and C by approximately 3 fps. The nozzles are already included in the plant FAC Program and will continue to be monitored for future wear.

Horizontal portions of the ES System piping are expected to develop either a semi-annular pattern, or to contain a liquid-phase portion that is small enough to be carried over. Vertical upward flows are expected to develop annular or mist flow patterns so that effective MCO will occur. Void coefficients associated with the vertical downward flowing portions of the system exceed minimum acceptance criteria with enough margin that slug patterns are not expected.

9.3 Heater Drains System

9.3.1 Introduction

The Heater Drains System was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The turbine cycle has six stages of feedwater heaters (FWHs). Each stage consists of three strings of heaters.

The drains from the heaters 35 and 36 are collected in the heater drain tank and then pumped by two half-size heater drain pumps to the suction of the main feedwater pumps (MFPs). The drains from heaters 34, 33, 32, and 31 flow cascade from higher pressure to lower pressure heaters. The combined drains in heaters 31 flow to the condenser. Bypass drain lines to the condenser for each heater and the heater drain tank dump drains directly to the condenser on high level are also provided.

As part of the plant's turbine water induction prevention features for events such as a heater tube rupture, a second emergency drain is required for condenser neck heaters 32 and 31 since a non-return valve cannot be provided in the extraction steam lines. On high-high level in these heaters, the emergency lines will open to drain additional flow to the condenser.

Simultaneously, the level control valves (LCVs) on the bypass drain line to condenser will remain open and the cascading drain flow from the preceding heaters will be isolated.

Moisture Separators, Reheaters, and Moisture Pre-Separators Drain System

Each moisture separator drains to its associated moisture separator drain tank. The moisture separator drain tanks flow to the heater drain tank during normal plant operation and to the drain collecting tank during startup, shutdown, or high water level conditions. The drain collecting tank drains to condenser.

Each reheater drains to its associated reheater drain tank. The reheater drain tanks flow to heaters 36. In the abnormal situation of high water level, the reheater drains are diverted to the condensers.

The moisture pre-separators consist of moisture pre-separators (MOPs) combined with special crossunder pipe separators (SCRUPs). The MOPs/SCRUPs drain system starts at the upstream end of the crossunder piping and runs to the heater drain tank. The main feature of the MOPs/SCRUPSs drain system is the separation chamber. The MOPs/SCRUPs drains

enter the separation chamber from the bottom. The liquid portion of the drains exits at the side of the separation chamber through a line that is equipped with a manual throttle valve. This line forms a loop-seal. The vapor portion of the drains exits at the top of the separation chamber through a vent line that is equipped with a control station and manual throttle valves. The level of water in the separation chamber can and will be fine-tuned by the operators in response to plant operating conditions.

The MOPs/SCRUPs and reheater drains are returned to the thermal cycle by pumping the heater drain tank into the suction of the feedwater pumps

Normal Operating Vents Lines of Heaters to Condensers

The normally operating vent lines of heaters are directed to the condenser through piping provided with globe valves for isolation or throttling of the flow.

Scavenging Steam to Reheaters

This additional heating steam supplied to the reheater, called scavenging steam, ensures that all reheater tubes are flowing clearly and a vapor space exists over condensed steam. This scavenging steam is directed to FWHs 36 during normal operation and to the condensers during start up.

Heaters Relief Valves

All heaters, with the exception of condenser neck heaters 31 and 32, are equipped with shell-side relief valves for overpressure protection of heater shells in the event of rupture of heater tube. These heaters, 31 and 32, have no isolation valves in their extraction lines from the low-pressure (LP) turbine and, therefore, have no relief valves for the shell.

9.3.2 Input Parameters and Assumptions

A current operating (benchmark) heat balance, tuned to the current plant operating characteristics and SPU heat balances at 1.0-, 1.5-, and 3.0-inch HgA condenser pressures, were used in the evaluation of the system. Additionally, these heat balances included a margin of 0.5 percent as a conservatism for evaluation purposes. Each of these heat balances and the corresponding parameters were reviewed and the most conservative case was chosen for the specific evaluation being performed.

Plant design basis documents, system descriptions, equipment and piping specification, drawings, and calculations provided system and component design parameters.

9.3.3 Description of Analysis and Evaluation

Hydraulic Analysis of Operation of Heater Drain Pumps and Associated Suction and Discharge Piping System

Refer to Section 9.4 of this report for the analysis of heater drain pumps and associated suction and discharge piping at SPU conditions.

FWHs, Moisture Separators, Reheaters, and Heater Drain Tanks Level Control Valves

The change in the flow coefficient (percent C_V difference) of the LCVs at the current operating and SPU conditions has been determined based on the heat balance parameters.

A generic flow characteristic curve has been used to determine the expected change of valve position at SPU conditions based on current valve position and percent C_V difference. The expected change of valve position at SPU conditions has been added to the current opening position to predict the opening position of the normally operated drain valves after SPU.

If the opening position of LCVs exceeds 75 percent at SPU conditions or the change in valve opening position at current and SPU conditions is significantly different, a detailed pressure drop analysis is performed to determine the change of valve position from current and SPU conditions.

The LCVs on bypass lines from heaters to the condenser are closed during normal operation and are opened when the normal drain line is not in service. The design of these bypass lines and valves is the same as the normally operated level control valve for the subject heater and assumed to be adequately sized for SPU conditions when the corresponding normal drain valves are found to be adequate.

The required C_V of heater drain tank bypass and condenser neck heaters emergency dump to condenser LCVs at SPU is expressed in percentage of maximum C_V as 100 x [$C_{V\ UPRATE}/C_{V\ MAX}$]. The expected opening positions of heater drain tank bypass and condenser neck heaters emergency dump to condenser LCVs at SPU conditions have been determined from the generic flow characteristic curve.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The following drain lines are gravity-flow lines, not equipped with control valves, and are evaluated as self-venting or non-self venting:

- FWHs 35 to the heater drain tank, non-self-venting
- Moisture separators to moisture separator drain tanks, self-venting
- Moisture separator drain tanks to heater drain tank, non-self-venting
- Reheaters to reheater drain tanks, non-self-venting

The self-venting gravity-flow drain lines are evaluated to comply with the criteria:

- Froude number (F_N) shall be less than approximately 0.3
- Slope of piping shall be greater than 1/2 inch per foot

The non-self-venting gravity-flow drain lines are properly designed when the static head available exceeds the friction head loss in the lines. If static head is too low, the fluid will back up into the source vessel. If friction head loss is too low, the flow velocities will be excessive and vapor may be entrained in the liquid, causing unstable two-phase flow.

Flow Regimes of Fluid Flow in Piping Downstream of Reheater Drain Tanks LCVs

The reheater drain piping and valves have a lower flow rate during SPU operation than current conditions. Downstream piping of reheater drain tank level control valves, an unstable flow regime, such as slug flow, could develop in long horizontal runs. Flow regime is evaluated by computing Baker parameters B_X and B_Y and applying them to Baker's map for two-phase flow regimes.

Scavenging Steam Vent Chamber Discharge Lines

Each moisture separator reheater (MSR) has a 3-inch vent chamber discharge line designed to accept approximately 26 percent of the reheater steam flow at 7.7 percent quality. These discharge lines are directed to heaters 36 during normal operation and to the condenser during start up. The flow in this 3-inch line is governed by a 3/4-inch control station. To evaluate two-phase choked flow in the control section, critical flow analysis software has been used that is based on the Henry-Fauske model.

Heater Shell-Side Normal Operating Vent System

The heater shell-side normal operating vent system has been analyzed to confirm that the Heat Exchanger Institute (HEI) recommended flow at SPU conditions can be vented (0.5 percent of the steam entering the FWHs at SPU conditions).

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

The FWHs 33, 34, 35, and 36 and the heater drain tank have relief valves for overpressure protection. The set pressure of the heater relief valves should be equal to or less than the design pressure of its shell side. The set pressure of the heater drain tank relief valve should be equal to or less than the heater drain tank design pressure.

The heater shell-side relief valves were evaluated for compliance with the HEI standard industry guidelines that the relief valve is capable of passing the larger of the following flows with 10percent accumulation:

- Minimum of 10 percent of the feedwater flow through the heater at maximum load capability based on average tube-side temperature.

- Flow based on the rupture of one heater tube resulting in two open ends discharging as orifices of a diameter equal to the inside diameter of the tube with an orifice discharge coefficient of 0.9 and a pressure difference across the orifices equal to the difference between the tube and shell design pressures.

The heater drain tank accepts drain flows from heaters 35 and 36, moisture separator drain tanks, and MOP drain tank. The heater drain tank relief valves were evaluated by comparing the total of all drain flows into the tank with the rated capacity of the two valves.

Piping, Valves, and Component Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures of heaters, MOPs/SCRUPs, moisture separators, and reheaters drain/vent system at SPU conditions are compared with the piping, valves, tank, and heater shell design/rated pressures and temperatures.

Flow-Accelerated Corrosion of Drain and Vent Lines

The piping velocities were calculated at SPU conditions and compared to standard industry velocity criteria as a measure of whether there was a greater potential for flow-accelerated corrosion (FAC). The potentially contributing factors to FAC, such as flow path geometry, material composition, flow velocities, fluid temperatures, and flashing service conditions, were evaluated to determine if a particular pipe needed to be added to the current FAC Program.

Drain Inlet and Outlet Nozzle Velocities of Heaters

The drain inlet and outlet nozzle velocities of heaters at SPU conditions were compared with HEI standard industry guidelines for prevention of undue wear of the nozzles and to determine whether any nozzles needed to be added to the present scope of the FAC Program.

Inlet and Outlet Drain Flows – Effects on FWHs Internals

The SPU drain inlet and drain outlet flow rates of the FWHs were evaluated to determine the effects on tube vibration and erosion of internal subcomponents and support structures.

9.3.4 Acceptance Criteria

FWHs, Moisture Separators, Reheaters, and Heater Drain Tank LCVs

The acceptance criteria for the LCV position is that the valve shall be open below 75 percent at full-load SPU operation to provide adequate assurance of long-term control margin and operability.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The drain lines with gravity flow should be self-venting if the liquid Froude Number is less than approximately 0.3 at SPU conditions and slope is greater than 1/2 inch per foot. The satisfactory operation of non-self-venting gravity-flow drain lines is performed when the static head available exceeds the friction head loss in the lines.

Flow Regimes of Fluid Flow in Piping Downstream of Reheater Drain Tanks LCVs

The piping downstream of reheater drain tanks level control valves should not have any unstable flow regime such as slug flow at SPU conditions.

Scavenging Steam Vent Chamber Discharge Lines

The scavenging steam vent chamber discharge line should be adequately sized to pass the required flow at SPU conditions.

Heater Shell-Side Normal Operating Vent System

The existing piping design should be capable of removing the expected non-condensable gases per the HEI standard industry guidelines at SPU conditions.

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

The set pressure of the heater shell-side relief valve should be equal to or less than the associated heater shell design pressure. The set pressure of the heater drain tank relief valve should be equal to or less than the heater drain tank design pressure.

The HEI-standard industry guideline of flow capacity for heater shell-side relief valves should be bounded by design flow capacity of heater shell-side relief valves.

The total incoming flow to the heater drain tank should be bounded by the total design flow capacity of heater drain tank relief valves.

Piping, Valves, and Component Design Pressures and Temperatures

The acceptance criteria is that the maximum sustained system operating pressures and temperatures at SPU conditions be bounded by design or rated pressures, and temperatures of piping and components.

FAC of Drain and Vent Lines

The piping velocities at SPU conditions associated with the single-phase flow of drain lines for the heater, MOPs/SCRUPs, moisture separator, and reheater drain system should be bounded by the standard industry velocity criteria. Other potential FAC influences, such as flow path geometry, material composition, flow velocities, flashing service conditions, and fluid temperature >200°F are also considered.

Drain Inlet and Outlet Nozzle Velocities of Heaters

The drain inlet and outlet nozzle velocities of heaters at SPU conditions should not appreciably increase the potential for wear and FAC.

Inlet and Outlet Drain Flows – Effects on FWHs Internals

The SPU drain inlet and drain outlet flow rates of the FWHs cannot cause destructive tube vibration or the erosion of internal subcomponents and support structures so that their function is impaired.

9.3.5 Design Criteria

The heater drain system is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety system.

9.3.6 Results and Conclusions

The heater, moisture separator, reheater, and pre-separator drain system are capable of accomplishing their design functions during SPU as discussed in the following paragraphs.

FWHs, Moisture Separators, Reheaters, and Heater Drain Tank LCVs

All normally operating, bypass, and emergency drain line LCVs are capable of transporting the required flows at SPU conditions with the open position below 75 percent.

FWHs, Moisture Separators, and Reheaters Gravity Drain Lines

The gravity-flow lines that satisfy the Froude number criterion for self-venting flow at current conditions will also do so at SPU conditions. The other gravity-flow lines are non-self-venting, but they are not observed to cause problems at current conditions. Based on comparison of flow velocity, they are not expected to exhibit any problem at SPU conditions.

MOPS/SCRUPS Drain Lines

The MOPs/SCRUPs drain system was modified with enough adaptability to accommodate the higher flows resulting from expected 6-percent SPU. The drain and vent throttle valves can be adjusted to accommodate 8.4 percent increased flow at SPU. In addition, there are provisions for condensate fill to sub-cool the drains and manual venting at the high point of the loop seal. The MOPs/SCRUPs drain system is operating in a satisfactory manner at the current conditions and expected to do so at SPU conditions.

Flow Regimes of Fluid Flow in the Piping Downstream of Reheater Drain Tanks LCVs

The flow downstream of the reheater drain control valves is an annular two-phase regime except for a small pipe length that approaches slug flow regime, at SPU conditions. Based on current operating conditions and the decease in flow in these lines of nominally 5 percent under SPU conditions no problems are expected in this section of piping. These lines will be considered under vibration monitoring during SPU power ascension.

Scavenging Steam Vent Chamber Discharge Lines

The mass flow in the scavenging steam vent chamber discharge line at SPU conditions is 9.45-percent lower than current condition. This discharge line is adequately sized for SPU conditions.

Heater Shell-Side Normal Operating Vent System

The evaluation concluded that the existing piping design of the operating vent system from all heaters to condenser is capable of removing the expected non-condensable gases per standard industry guidelines at SPU conditions.

Heater Shell-Side and Heater Drain Tank Relief Valves for Overpressure Protection

Heater shells must not be overpressurized in the event of tube or tubesheet failure because:

- The set pressures of relief valves are equal to or less than the design pressures of associated FWHs.
- The HEI standard industry guideline of maximum flow capacity for relief valves for heaters 33, 34, 35, and 36 is bounded by design flow capacity of the relief valves.

The total incoming flow to heater drain tank (that is, moisture separators drain, MOPs/SCRUPs drain, and heaters 35 and 36 drains) is less than the total relieving flow capacity of heater drain tank relief valves. The set pressures of relief valves are equal to the design pressures of the heater drain tank. Hence, the heater drain tank must not be overpressurized in the extreme event of complete loss of both heater drain pumps and the heater tank emergency drain system to condenser.

Piping, Valves, and Component Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures of the FWHs and moisture separators, reheaters, and separating tanks drain and vent piping systems at SPU conditions are enveloped by the currently operating piping design pressures and temperatures.

The maximum sustained operating pressures and temperatures of heater shells at SPU conditions are enveloped by heater shell design pressures and temperatures except for heaters 36A/B/C. The maximum normal sustained temperatures of heaters 36A/B/C shells exceed the heater design temperature by 29°F. The materials of shells, elliptical heads and channels of the heaters 36A/B/C are carbon steel SA 516 Grade 70. The nozzles are carbon steel SA 105 and SA 516 Grade 70. The shell design can accept the higher SPU temperatures since the maximum allowable stress value of materials does not change in the temperature range of –20° to 650°F.

The maximum sustained operating pressures and temperatures of heater, moisture separator, reheater drain tanks at SPU conditions are enveloped by the tank design pressures and temperatures

FAC of Drain and Vent Lines

All of the piping experiences velocities below the industry standard pipe velocity limit. All of the carbon steel piping with temperatures exceeding 200°F and flashing service are presently in the FAC Program except heaters 32A/B/C operating vent lines. The operating vent lines for heaters 32A/B/C will be added in FAC Program.

Heater Drain Inlet and Outlet Nozzle Velocities of FWHs

The drain inlet and outlet velocities of the FWHs at SPU conditions are below the HEI standard industry guidelines and FAC program screening criteria except for the drain outlet nozzles of heaters 33A/BC, 34A/B/C, 35A/B/C and 36A/B/C and drain inlet nozzles of heaters 32A/B/C and 33A/B/C.

In consideration of this condition, Entergy currently carries all these nozzles in the FAC Program.

Inlet and Outlet Drain Flows – Effects on FWHs Heaters Internals

The SPU drain inlet flow rates are above the existing design values for FWH 36A/B/C. For FWH 33A/B/C, FWH 32A/B/C, and FWH 31A/B/C, the SPU drain inlet flow rates are below the existing design values. The SPU drain outlet flow rates are above the existing design values for FWH 36A/B/C, FWH 34A/B/C, FWH 32A/B/C, and FWH 31A/B/C. For FWH 35A/B/C and FWH 33A/B/C, the SPU drain outlet flow rates are below existing design values. FWH 36A/B/C, FWH 34A/B/C, FWH 32A/B/C, and FWH 31A/B/C will be monitored to determine whether destructive tube vibration or the significant erosion of internal parts will occur at the higher SPU flow rates.

9.4 Condensate and Feedwater System

9.4.1 Introduction

The Condensate and Feedwater System (C&FS) was evaluated in conjunction with stretch power uprate (SPU) conditions to determine the extent to which system design parameters bound SPU conditions.

The Condensate System was designed to transport condensate and low-pressure (LP) heater drains from the condenser hotwell through the Condensate Polishing System (CPS) and five stages of feedwater heating to the suctions of the main feedwater pumps (MFPs). The CPS is installed within the condensate system between the condensate pumps and the first stage of feedwater heaters (FWHs). Normally, five deep-bed polisher vessels and five condensate post-filter vessels are in service, and one polisher vessel and one condensate post-filter vessel are on standby. Three one-third capacity condensate pumps are provided. Three one-half capacity condensate booster pumps are provided to recover the pressure drop induced by the CPS.

Two half-size heater drain pumps are designed to transport the high-pressure (HP) heater drains from the heater drain tank into the condensate header upstream of the MFPs.

The Feedwater System increases the pressure of the condensate/heater drains for delivery to the steam generators. The Feedwater System also provides the final stage of feedwater heating and controls the feedwater flow via the regulating valves and feedwater pump turbine speed control system. This system has two half-size steam turbine-driven MFPs.

9.4.2 Input Parameters and Assumptions

SPU heat balances were developed to define the thermal plant performance at the current operating conditions and at SPU conditions. A current operating (benchmark) heat balance, tuned to the current plant operating characteristics and SPU heat balances at 1.0-, 1.5-, and 3.0-inch HgA condenser pressures, was used to evaluate the system. For evaluation purposes, these heat balances included a margin of approximately 0.5 percent. Each of these heat balances and the corresponding parameters were reviewed and the most conservative case was chosen for the specific evaluation of C&FS.

Plant design basis documents, system descriptions, equipment and piping specifications, calculations, and drawings provided system and component design parameters.

9.4.3 Description of Analysis and Evaluation

Operation at SPU conditions affects a variety of system parameters, such as flow rates and velocities, temperatures and pressures, and the thermal performance of the FWHs. The C&FS was evaluated to confirm its ability to operate successfully at the SPU conditions. The following subsections describe the specific evaluations.

Hydraulic Analysis of Condensate, Feedwater, and Heater Drain Pump Systems

The hydraulic model of the C&FS operation under SPU conditions (including associated portions of the heater drain pumps suction and discharge system) was developed, and included the following scenario cases:

Case 1: Flow analysis for three condensate pumps, two main feedwater pumps. two heater drain pumps, and two condensate booster pumps (CBPs) and CPS in operation at 100-percent power level for the SPU.

Case 2: Flow analysis for three condensate pumps, two main feedwater pumps, and two heater drain pumps in operation at 100-percent power level for the SPU. CPS and CBPs are not in operation.

Case 3: Flow analysis for three condensate pumps, three CBPs, one heater drain pump, and two main feedwater pumps in operation and loss of one heater drain pump resulting from 50-percent load reduction. The pumps must provide 96 percent of full-power feedwater flow for the SPU to steam generators with steam generators' pressure increased by 100 psi above full-power steam generator pressure for the SPU during a 50-percent load reduction. The condensate polisher and post- filter vessels are bypassed but the three CBPs are operational.

Component and Piping Design Pressures and Temperatures

The maximum sustained SPU system operating pressures and temperatures were compared with the piping design/rated pressures and temperatures of piping, valves, flanges, FWH tubes, and pump casings to verify that the design bounds SPU sustained operating conditions.

Velocity and Flow-Accelerated Corrosion of Condensate, Feedwater, and Heater Drain Pump Piping

The piping velocities were calculated at SPU conditions and compared to standard industry velocity criteria as a measure of whether there was a greater potential for flow-accelerated corrosion (FAC). The potential contributing factors to FAC, such as flow path geometry, material composition, flow velocities, fluid temperatures, and service conditions etc., were evaluated to determine if a particular pipe needed to be added to the current FAC Program.

FWHs - Nozzle Velocities, Tube Velocities, and Past Inspection Results

The feedwater inlet and outlet nozzle velocities at SPU conditions were compared to Heat Exchanger Institute (HEI) standard industry guidelines to determine the potential for increased wear and FAC. The FWH tube velocities at SPU conditions were compared with HEI-recommended velocities for FWH tubes.

The FWHs inspection results were evaluated to determine whether the actual operating condition of these components, including any existing degradation in performance or component materials, affected their ability to perform under SPU conditions.

Condensate Booster, Condensate, and Heater Drain Pumps Brake Horsepower

The CBPs, condensate, and heater drain pumps' brake horsepower (bhp) at SPU conditions were compared with CBP, condensate, and heater drain pump motors' rated horsepower for acceptability of operation under SPU conditions.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The probability of excessive condenser tube vibration and a condenser pressure increase (that is, loss of vacuum) during a main steam dump following a 50-percent turbine load reduction at SPU conditions was evaluated to ensure that the condenser HP alarm and turbine trip setpoint were not exceeded.

Condenser Hotwell Volume

The volume of the condenser hotwell was evaluated to confirm that there would be sufficient volume to accept the condensate flow at SPU full load with free volume for condensate surge protection and to accommodate system surges during load rejection.

NRC Generic Letter 89-10 MOV Program – Motor-Operated Valve Program Review

The feedwater motor-operated valves (MOVs) BFD-MOV- 2-31, BFD-MOV-2-32, BFD-MOV-5-1, BFD-MOV-5-2, BFD-MOV-5-3, BFD-MOV-5-4, BFD-MOV-90-1, BFD-MOV-90-2, BFD-MOV-90-3, and BFD-MOV-90-4 are included in the Generic Letter (GL) 89-10 MOV Program. The differential pressure calculations were reviewed to evaluate the effects of SPU on the operating parameters for these valves (for example, maximum design basis opening/closing differential pressures/line pressures).

9.4.4 Acceptance Criteria

The C&FS is considered acceptable under SPU conditions provided the criteria in the following paragraphs are met.

Hydraulic Analysis of Condensate, Feedwater, and Heater Drain Pump Systems

The main feedwater pumps, operating in conjunction with condensate pumps, heater drain pumps, and with/without CBPs must be capable of providing the required heat balance flow rate and pressure to steam generators at 100-percent SPU power level and transient conditions.

The CBPs, condensate, main feedwater, and heater drain pumps must have sufficient net positive suction head available (NPSHA) with sufficient margin over net positive suction head required (NPSHR) at all modes of system operation.

Component and Piping Design Pressures and Temperatures

Maximum sustained system operating pressures and temperatures at SPU conditions will be bounded by the piping design and the component rated (or design) pressure and temperature.

Velocity and FAC of Condensate, Feedwater, and Heater Drain Pump Piping

The piping velocities and other potential FAC influences, such as operating temperature >200°F, at SPU conditions in the condensate, feedwater, and heater drain pump systems will not cause the potential for increased FAC.

Feedwater Heaters - Nozzle Velocities, Tube Velocities, and Past Inspection Results

The feedwater inlet and outlet nozzle velocities shall not significantly increase the wear and FAC of the nozzles.

Condensate Booster, Condensate, and Heater Drain Pumps bhp

The CBPs, condensate, and heater drain pumps' bhp at SPU conditions should be bounded by CBP, condensate, and heater drain pump motor-rated horsepower.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The condenser HP alarm and turbine trip set point should not be exceeded with main steam dump resulting from a 50-percent turbine load reduction.

The tube support spacing recommended by HEI for prevention of tube vibration at SPU conditions should exceed the existing tube support spacing.

Condenser Hotwell Volume

The condenser hotwell must contain sufficient volume to accept full-condensate flow at SPU conditions for 4 minutes with free volume for condensate surge protection and to accommodate system surges during load rejection.

NRC Generic Letter 89-10 MOV Program – MOV Program Review

The impact of SPU conditions on the maximum design basis opening and closing differential pressures/ line pressures in the MOV differential pressure calculations are evaluated in the station MOV program.

9.4.5 Design Criteria

The C&FS was designed to transport condensed steam and low-pressure (LP) heater drains from the condenser hotwell through condensate polishing system and six stages of feedwater heating for the improved cycle efficiency to the steam generator at the heat balance required pressure and temperature.

The portion of the FCS is nuclear safety-related and required for safe shutdown of the reactor. The remaining portion is not required for safe shutdown of the reactor, has no safety-related function, and is designed as non-nuclear safety system.

The C&FS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to

the intent of the newer criteria. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50, Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

Environmental qualification (EQ) of C&FS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 2) and Division of Operating Reactors (DOR) Guidelines (see LAR Section 11, and ER Section 10). Monitoring of the C&FS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 3). The C&FS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREGs 0578 and 0737 (References 4 and 5). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the C&FS to meet these requirements. Therefore, the C&FS continues to meet the criterion requirements.

Criterion as it relates to the accident analyses and NSSS/BOP interface can be found in Sections 4 and 5 of this document.

Other criteria required to meet SPU conditions are listed in subsection 9.4.4, of this section.

9.4.6 Results and Conclusions

Specific results of each evaluation are discussed in the following paragraphs.

Hydraulic Analysis of Condensate, Feedwater, and Associated Heater Drain Pump System

The feedwater/condensate/associated heater drain pump system is capable of providing the required heat balance flow rate and pressure to steam generators at 100-percent SPU power level and transient conditions with sufficient margin in control valve open position and feedwater pump turbine speed.

The analysis also confirmed that the CBPs, condensate, feedwater, and heater drain pumps will have sufficient NPSHA with margin over NPSHR in all modes of system operation.

The analysis also confirmed that the feedwater pump suction header pressures are higher than the pump speed runback set pressures with sufficient margin.

Component and Piping Design Pressures and Temperatures

The maximum sustained operating pressures and temperatures for piping at SPU conditions are enveloped by the existing piping design pressures and temperatures, except for the maximum normal sustained operating temperatures for the condensate pump suction piping and DCT outlet piping to condenser (112°F @ 3.0 inch HgA condenser pressure) exceeds design temperature (10°F) by 12°F. The maximum sustained operating temperature for these piping will be 89°F @ 1.5 inch HgA condenser pressure and 77°F @ 1.0 inch HgA condenser pressure respectively. The IP3 operating test data indicates that condensate pressure varies from 1.0 inch HgA to 2.50 inch HgA at current conditions. The maximum sustained operating temperature for these piping will be 104°F @ 2.50 inch HgA condenser pressure. The C&FS has been evaluated based on 3.00 inch HgA condenser pressure heat balance for conservatism and additional margin. The materials of this piping are A155, grade C55, Class 2 for pipe 30-inch-to-54-inch, A53, grade B for 3-inch-to-24-inch and A106, grade B for 2-1/2 inch and smaller. The pipe walls of condensate pumps suction piping from condenser and DCT outlet piping to condenser are acceptable at SPU since the stress value of carbon steel piping material remains unchanged in the temperature range of -20° to 650°F and the existing pipe walls/schedules will remain unchanged based on maximum normal sustained SPU temperature (112°F) and design pressure (30 psig). Also, the rated temperature of the valves and flanges in this piping (that is, –20 to 150°F) bounds the maximum normal sustained temperature (that is, 112°F).

The maximum sustained operating pressures and temperatures at SPU conditions are enveloped by the rated/design pressures and temperatures of valves, flanges, FWH tubes, and pump casings.

Velocity and FAC of Condensate, Feedwater, and Heater Drain Pump Piping

The majority of the piping experiences velocities below the standard industry pipe velocity guideline. The temperature criterion for FAC susceptibility is greater than 200°F. All the piping from feedwater heaters 31A/B/C outlet to steam generators with temperatures exceeding 165°F are presently in the FAC Program. The limited number of pipes with velocities above the applicable guideline are considered susceptible to FAC and are presently in the FAC Program.

The velocity of 54-inch and 30-inch pipes from the common suction header to each condensate pump's suction nozzle exceeds the velocity guideline by a relatively small amount (3.08 ft/sec calculated for 54-inch pipe and 3.31ft/sec for 30-inch pipe versus 3.0 ft/sec guideline). Although, the velocity is exceeded slightly, the condensate pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 29 ft versus NPSHR = 14 ft). Hence, the system capability is not impaired. The maximum operating temperatures are in the range of 77°-112°F. Therefore, these pipes are not an FAC concern.

The velocity of 30-inch common suction line (15.96 ft/sec) and the two 24-inch suction pipes (12.94 ft/sec), one to each feedwater pump, exceeds the velocity guideline of 10 ft/sec. Although the velocity guideline is exceeded, the feedwater pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 390 ft versus NPSHR = 135 ft). Hence, the system capability is not impaired. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The velocity of two 18-inch heater drain pump suction lines, one to each pump from the heater drain tank, exceed the velocity guideline (6.16 ft/sec actual velocity versus 4 ft/sec guideline for a saturated drain line). Although the velocity guideline is exceeded, the heater drain pumps have sufficient NPSHA with ample margin over NPSHR (NPSHA = 80 ft versus NPSHR = 28 ft). Hence, the system capability is not impaired. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The velocity of two 20-inch discharge pipes, one from each feedwater pump discharge to common discharge header exceeds the velocity guideline slightly (20.61 ft/sec versus 20.0 ft/sec guideline). These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

The two 4-inch/ 6-inch feedwater pump recirculation lines, one from each pump to the drain collecting tank, significantly exceed the velocity guideline of 20 ft/sec (111 ft/sec in the 6-inch portion and 267 ft/sec in the 4-inch portion). These pipes are in service only during plant startup or shutdown and are normally secured at power levels greater than 50 percent. These pipes are already part of the FAC Program and will continue to be monitored after SPU implementation.

FWHs - Nozzle Velocities and Tube Velocities

The FWH tube velocities at SPU conditions meet the HEI standard guidelines.

Feedwater inlet and outlet nozzle velocities of FWHs 36A/B/C, 35A/B/C, 34A/B/C, 33A/B/C, 32A/B/C, and 31A/B/C exceed HEI standard guidelines as follows:

- Heater 36A/B/C: 14.73 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 35A/B/C: 15.94 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 34A/B/C: 16.26 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 33A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 32A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines
- Heater 31A/B/C: 16.25 ft/sec versus 10 ft/sec @ 60°F HEI guidelines

The current FAC Program includes the outlet nozzles of FWHs 31A/B/C and inlet and outlet nozzles of feedwater heaters 32A/B/C, 33A/B/C, 34A/B/C, 35A/B/C, and 36A/B/C. Although, the velocities in FWHs 31A/B/C condensate inlet nozzles exceed HEI guidelines, the nozzles are part of a single-phase line, which is below the temperature guideline of FAC susceptibility of 200°F. Based on EPRI guidelines and IP3 FAC Program procedure, these nozzles are excluded from the FAC Program. Based on the above information, all heater nozzles are acceptable for SPU conditions.

Condensate Booster, Condensate, and Heater Drain Pumps BHP

The CBPs', condensate, and heater drain pumps' bhp at SPU conditions are enveloped by CBPs, condensate, and heater drain pump motor-rated horsepower.

Condenser Operation with Main Steam Dump Resulting from 50-Percent Turbine Load Reduction

The condenser vacuum will reduce to approximately 25.4-inch Hg vacuum at maximum 95°F circulating water temperature. This is slightly below the condenser low vacuum alarm set point of 26-inch Hg but above the turbine trip set point of 18-inch Hg vacuum. Therefore, the alarm might be actuated at infrequent circulating water temperature of 95°F, but the turbine will not trip in the event of main steam dump resulting from 50-percent turbine load reduction.

The existing condenser tube support spacing is more robust than the HEI requirement and, therefore more structurally adequate to preclude damaging flow-induced vibration.

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The design inputs in the calculations such as condensate pump shutoff head, maximum MFP discharge pressure/minimum MFP suction pressure/minimum MFP speed of MFP speed control system, steam generator pressure at which AFW pump starts, MFP coast down head, condenser high water level set point etc., for maximum design basis opening and closing differential pressures and line pressures of MOVs are not affected by the SPU conditions.

Condenser Hotwell Volume

The condenser hotwell volume of 114,000 gallons provides for more than 5 minutes of storage at SPU that exceeds the 4 minutes requirement to accept full-condensate flow at SPU conditions. Hence, the condenser hotwell will contain free volume for condensate surge protection and to accommodate system surges during load rejection.

Condensate Polishing System

The CPS operates during plant startup and infrequently during normal power operation to maintain the required purity of the condensate for the steam generators. The system is designed for a continuous operation at maximum flow of 24,000 gpm with inlet maximum pressure of 700 psig and temperature of 140°F. The 140°F temperature is based on precluding thermal degradation of the resin. The maximum allowable flow/pressure/temperature of CPS design envelopes the SPU flow/pressure/temperature of 20,328 gpm, 496 psig and 112°F through CPS.

9.4.7 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR50.46, *Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors,* September 16, 2003.

3. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

4. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations,* July 1979.

5. NUREG-0737, *Clarification of TMI Action Plan Requirements,* November 1980.

9.5 Steam Generator Blowdown System

9.5.1 Introduction

The Steam Generator Blowdown System (SGBS) is designed to extract blowdown water from the secondary side of the steam generators as a means of removing particulates and dissolved solids to control water chemistry in the steam generators. By maintaining the proper water chemistry, steam generator tube corrosion is reduced, thereby minimizing the likelihood and magnitude of tube leaks. Steam generator blowdown is collected from the steam generator and is normally directed to the blowdown recovery system. Blowdown flow may also be directed to the blowdown flash tank. The blowdown flash tank is used to process large volumes of blowdown from a single steam generator and is vented to the atmosphere and drains to the Service Water System (SWS). The blowdown recovery system consists of four manual control valves (one for each of the blowdown recovery lines from the steam generators), three heat exchangers, and a set of pre-filters, demineralizers, and post-filters with a bypass and pressure control and bypass valve station. The blowdown recovery system transfers SGBS heat to the condensate system and returns the blowdown recovery inventory to the drains collection tank in the condensate system.

The SGBS also provides samples of the secondary side water in the steam generator. These samples are used for monitoring water chemistry and for detecting the amount of radioactive primary coolant leakage through the steam generator tubes. In the event of a high-radiation signal, both isolation valves in the blowdown lines close automatically. The valves also shut on a Phase A containment isolation signal, an automatic start signal for the motor-driven auxiliary feedwater pumps (MDAFWPs), and also fail shut on loss-of-air or electrical power.

The portion of the SGBS from the steam generator connections inside containment, up to and including the containment isolation valves outside containment, are considered a part of the containment boundary and are safety-related.

9.5.2 Input Parameters and Assumptions

The SGBS was designed to accommodate blowdown flows of up to 4 percent of the total feedwater flow rate. This corresponds to a total blowdown flow rate of 960 gpm from all four steam generators. During plant operation, total blowdown flow rates are maintained between 0.2 percent and 1.0 percent of the total feedwater flow.

The SGBS is currently operating with a blowdown flow of 37.5 gpm per steam generator for a total of 150 gpm.

The design of the steam generator permits:

- Continuous normal flow at 230 gpm per steam generator from each of the two steam generator nozzles.
- Flow at 335 gpm per steam generator from each of the two steam generator nozzles for short periods of operation, not to exceed 1 year cumulative over the life of the steam generator.

The blowdown recovery system is designed to process up to 300 gpm but is limited administratively to 265 gpm.

The SGBS piping is designed for 1085 psig and 600°F.

9.5.3 Description of Analysis and Evaluation

The SGBS was evaluated to verify that the required blowdown flow could be processed during stretch power uprate (SPU) conditions. The system design pressure, design temperature, pipe sizing, and flow velocities were reviewed against the SPU operating conditions.

Since the variables that affect blowdown flowrates are not affected by SPU (refer to Section 4.2 of this report), the blowdown flow rate is not affected by the SPU.

Westinghouse indicated that the minimum full-load steam generator steam pressure decreases approximately 26 percent from 762 psia to 567 psia for the SPU. This decrease in blowdown system inlet pressure may affect the required maximum Cv of the blowdown flow control valves. The blowdown control valves (HCV-1, 2, 3, and 4) were reviewed to confirm adequate control capability.

The piping velocities, operating temperatures, piping material, and service time during SPU operation were evaluated for the potential to accelerate pipe corrosion and the need to include these lines in the plant Flow-Accelerated Corrosion (FAC) Program.

9.5.4 Acceptance Criteria for Analysis

The SGBS is considered acceptable under SPU conditions by satisfying the following:

- The piping system can pass the evaluated blowdown flow rate at SPU conditions.

- The SPU maximum pressure and temperature conditions are bound by the piping and valve design pressures and temperatures.
- The flow velocities and/or operating temperatures above 200°F due to SPU conditions will not increase the potential for FAC in the SGBS lines fabricated from carbon steel.

9.5.5 Design Criteria

The SGBS is designed to extract blowdown water from the secondary side of the steam generators as a means of removing particulates and dissolved solids to control water chemistry in the steam generators. The SGBS also provides samples of the secondary side water in the steam generator that are used for monitoring water chemistry and detecting the amount of radioactive primary coolant leakage through the steam generator tubes.

Portions of the SGBS are safety-related. The SGBS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER) that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the SGBS to meet these requirements, therefore, the SGBS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to the NRC on August 16, 1984. SPU operation does not affect the ability of the SGBS to meet these requirements, therefore, the SGBS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the SGBS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the SGBS will continue to meet the criteria requirements.

Environmental qualification of SGBS electrical equipment important to safety is demonstrated in Environmental Qualification packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and Division of Operating Reactors (DOR) Guidelines (see Licensing of Amendment Request [LAR] Section 11, and Engineering Report [ER] Section 10). Monitoring of the SGBS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4).

The SGBS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the SGBS to meet these requirements. Therefore, the SGBS continues to meet the criterion requirements.

Design criteria related to the accident analyses and Nuclear Steam System Supply (NSSS)/ balance-of-plant (BOP) interface can be found in Sections 4 and 5 of this document. Design criteria required to meet SPU conditions are listed in the acceptance criteria above.

9.5.6 Results

The plant is currently operating with a blowdown flow of 37.5 gpm from each steam generator for a total flow of 150 gpm. The blowdown flow is not affected by SPU (refer to Section 4.2).

For SPU operation, the manual throttle valve on the blowdown recovery line from each steam generator (HCV-1, 2 ,3, and 4) may require repositioning. The throttle valves were evaluated for control capability due to the decrease in minimum full load steam generator pressures for SPU. Each valve has a maximum capacity in excess of power uprate blowdown flow rate (e.g. 240 gpm for each valve) at pressure drops of 100 psid. Backpressure regulator valve PCV-2 is designed to maintain the pressure drop across the HCVs to less than 100 psid. Consequently, these valves will retain adequate control capability at power uprate operation.

The blowdown system continues to be capable of continuous operation for the design life of the steam generator at a flow rate equal to 230 gpm. In addition, a maximum blowdown flow rate equal to 335 gpm is allowed for the equivalent of 1 year operation. These blowdown rates are per steam generator blowdown nozzle.

In regard to FAC, although the normal operating velocities are slow and the maximum velocities only occur for short durations, the portions of the SGBS fabricated from carbon steel (2-inch blowdown lines associated with steam generators 32 and 33) are monitored as part of the IP3 FAC Program, since the temperature is approximately 515°F and the lines can experience flashing flow due to the saturated conditions in the steam generators. The portions of the SGBS fabricated from stainless steel are excluded from the FAC Program.

The steam generator steam outlet temperature and pressure decreases from the original design values of 514.5°F/774.4 psia to 511.6°F/754.8 psia at SPU conditions. This slight decrease (-2.9°F and -19.6 psia) does not affect the main steam safety valve (MSSV) setpoints nor the design pressure (1085 psig) and temperature (600°F) of the steam generators. Therefore, the SGBS design pressure and temperature is not affected.

9.5.7 Conclusions

The design and operation of the IP3 SGBS is not affected by changes in SPU parameters and therefore the SGBS is acceptable for the SPU conditions. Aside from the possible need to reposition the throttle valves controlling blowdown flow rate, no changes are required for SPU operation.

Due to the operating temperature and saturated, potentially flashing process conditions, the blowdown lines fabricated from carbon steel will remain in the existing FAC Program.

9.5.8 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979*, June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.6 Essential and Non-Essential Service Water System

9.6.1 Introduction

The Indian Point 3 (IP3) Essential and Non-Essential Service Water System (SWS) is a safety-related system that provides cooling water from the Hudson River to essential components (loads that require cooling water immediately after a loss of power or an accident) and non-essential components (loads that do not require cooling water immediately after a loss of power or an accident) on both the nuclear and conventional sides of the plant. The cooling water removes waste heat from the equipment for all plant operating modes and rejects the waste heat to the Hudson River through a discharge canal. One set of three pumps provides water to the essential header, and the other set of three pumps supplies the non-essential header. Three SW backup pumps are provided that take suction from the Unit 2 discharge canal and discharge into the essential header. The backup pumps were originally provided to provide for a loss of intake structure. SW backup pump 38 was later designated for Appendix R supply to the Component Cooling Water Heat Exchangers in the event of a fire.

Essential SWS loads include:

- Containment recirculation fan cooling coils
- Containment recirculation fan motor cooling coils
- Instrument air cooling water heat exchangers (HXs)
- Diesel generator lube oil coolers and jacket water coolers (Note 1)
- Control room AC units (Note 1)
- Cooling for radiation monitors
- Feedwater pump coolers
- Turbine oil coolers

Non-essential SWS loads include:

- Component cooling water HXs
- Hydrogen coolers
- Exciter coolers
- Iso-phase bus (IPB) HXs
- Steam generator blowdown coolers
- Turbine building closed cooling water HXs
- Circulating water pump shaft seal and bearing cooling

(Note 1: This equipment can be manually fed from the non-essential header)

9.6.2 Input Parameters and Assumptions

The latest system hydraulic analysis provided the basis for the system alignments, valve/equipment controls and operation evaluated. Inputs for cooling flow rates and heat load requirements were provided by Westinghouse or developed based on the latest plant design specifications, drawings, licensing documents, design basis documents, test data and inspection reports and the results of the IP2 SWS SPU evaluation and confirmed with equipment suppliers.

9.6.3 Description of Analysis and Evaluations

The stretch power uprate (SPU) will increase the heat rejection to the SWS.

The latest system hydraulic analysis was evaluated to determine the effects of SPU operation.

The following were evaluated at SPU conditions:

- Heat load removal capability
- Flow adequacy to system components and SWS pump capacity and head
- Effects of higher outlet temperatures versus the existing piping design
- System stress analysis and environmental conditions
- Design pressure and temperature of system piping and components

The results of the IP3 SWS hydraulic analysis including system arrangement, flow requirements, heat load data, etc., and system/equipment requirements for meeting SPU conditions were compared to the IP2 SWS evaluation completed for SPU. Similarities and differences were noted and an evaluation completed.

9.6.4 Acceptance Criteria

The Essential and Non-Essential SWS is considered acceptable under SPU conditions provided the following conditions are met:

- The SWS remains capable of providing the required flow rate for each of its design functions (safety and non-safety) under SPU operating conditions.

- SWS pump operation at SPU flow conditions is within the acceptable margins of pump design parameters (for example, net positive suction head [NPSH], flow and total discharge head [TDH]) for all applicable operating modes.

- The SWS remains capable of performing its heat removal functions (safety and non-safety) specified for each component for all applicable operating modes.

- The design pressure and temperature of the SWS piping and components bound the SPU pressure and temperature conditions. The existing SWS pipe stress bounds SPU conditions and outlet SWS conditions are bound by existing plant environmental conditions.

9.6.5 Design Criteria

The SWS is designed to provide cooling water from the Hudson River to essential components (loads that require cooling water immediately after a loss of power or an accident) and non-essential components (loads that do not require cooling water immediately after a loss of power or an accident) on both the nuclear and conventional sides of the plant to remove waste heat and reject the waste heat to the Hudson River through a discharge canal for all plant operating modes.

Portions of the SWS are safety-related. The SWS was designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER) that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L, and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the SWS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the SWS will continue to meet the criteria requirements.

Environmental qualification of SWS electrical equipment important to safety is demonstrated in Environmental Qualification packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and Division of Operating Reactors (DOR) Guidelines (see Licensing of Amendment Request (LAR) Section 11, and Engineering Report (ER) Section 10). Monitoring of the SWS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4). The SWS is designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the SWS to meet these requirements. Therefore, the SWS continues to meet the criterion requirements.

Design criteria related to the accident analyses and Nuclear Steam System Supply (NSSS)/ balance-of-plant (BOP) interface can be found in Sections 4 and 5 of this document.

Design criteria required to meet SPU conditions are listed in the acceptance criteria above.

9.6.6 Results and Conclusions

The SPU will increase the heat rejection to the SWS. For the SPU evaluation, the existing SWS hydraulic analysis was used to evaluate the requirements of SPU operation and evaluate flow adequacy to system components and SWS pump capacity and head. The evaluation of the system included analysis of the heat load removal capability, effects of higher outlet temperatures, design pressure and temperature of system piping and components, and developed system stress analysis and environmental conditions. The IP3 hydraulic analysis assumed worst case conditions of low river-water level, design inlet temperature (95°F), and 18-percent degraded pump curves and atmospheric vents where applicable.

Adequate SWS and equipment performance (safety and non-safety) were verified under SPU conditions, including pump net pump suction head (NPSH) requirements, system flashing, strainer backwash capability, etc.

The evaluation verified that the SPU does not affect the flow requirements for any of the safety-related equipment cooled by the SWS. Some turbine plant equipment fed by the non-essential SWS header required increases in flow. Increased heat loads from the equipment were found to be bounded by the original equipment and system design. SWS instrumentation and controls were found to be adequate at SPU conditions.

The SWS remains capable of performing its heat removal functions (safety and non-safety) specified for each component for all applicable operating modes.

Outlet service water temperatures were confirmed to be within the system and equipment design specifications. The SWS piping and components' design pressure and temperature bound the SPU pressure and temperature conditions. The existing SWS pipe stress conditions bound SPU conditions and outlet SWS conditions are bounded by existing plant environmental conditions.

The Ultimate Heat Sink (UHS) for IP3 is the Hudson River. The Circulating Water System (CWS) (refer to Section 9.7 of this report) and Essential and Non-Essential SWS take cooling water from and discharge waste heat to the UHS. The analyses completed for these systems are based on the most conservative SPU heat balances that include a 0.5-percent margin.

The CWS is a non-safety-related, once-through system that uses six CWS pumps to supply water from the Hudson River, circulates it through the main condenser to condense the exhaust steam from the main turbine and other steam/water drains, and returns heated water back to the Hudson River.

Plant operation at the SPU conditions will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS to the Hudson River. The existing CWS pumps were not modified for SPU and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River were not affected by the SPU, the CWS discharge temperature to the Hudson River will increase, but is still within the original discharge permit limits.

As described in Section 11 of this report, the environmental issues associated with the issuance of an operating license for IP3 were originally evaluated in the *IP3 Final Environmental Statement* (FES) (Reference 7) (Volume 1, page I-1 Section I) and addressed plant operation up to a maximum calculated reactor power of 3216 MWt. The AEC, predecessor of the NRC, approved the FES in February 1975. In addition to the FES, the Indian Point State Pollutant Discharge Elimination System (SPDES) restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP3 Consent Order. Historic river temperature data (taken from 1993 to the present) were used in the SPU analyses. Increased heat rejection to the CWS and SWS at SPU conditions is expected to result in a nominal calculated increase in discharge temperature to the river. This temperature increase falls within the applicable SPDES permit thermal limits for IP3.

9.6.7 References

1. 10CFR50, Appendix R, Fire *Protection Program for Nuclear Power Facilities Operating Prior to January 1979*, June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation*, May 21, 1991.

3. 10CFR50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

7. *Indian Point Unit 3 Final Environmental Statement*, February 1975

9.7 Circulating Water System and Main Condenser

9.7.1 Introduction

The Indian Point 3 (IP3) Circulating Water System (CWS) is a non-safety-related system that provides cooling water for the main condenser of the turbine generator unit. The CWS is a once-through system that uses six CWS pumps to supply water from the Hudson River and circulate it through the main condenser to condense the exhaust steam from the main turbine and other steam/water drains, and returns heated water back to the Hudson River.

The main condenser is a conventional triple-shell, single-pass, divided waterbox, radial-flow surface condenser that condenses and deaerates exhaust steam from each of the three low-pressure (LP) turbines, two boiler feedwater pump turbine exhausts, the Steam Dump System, and other miscellaneous drains. Heat is removed by the CWS, where it is ultimately rejected to the Hudson River.

The Main Condenser Air Removal System is a non-safety-related system that removes non-condensable gasses from the main condenser to help maintain condenser vacuum. The Condenser Air Removal System consists of three hogging and three priming steam jet air ejectors (SJAEs). One hogging or one priming SJAE serves one condenser shell.

9.7.2 Input Parameters and Assumptions

Thermal cycle heat balances were developed to define the thermal plant performance at the current operating conditions and at SPU conditions. The CWS pumps ratings, main condenser data, and the assumptions made for the Main Condenser Air Removal System were used in the evaluation of the CWS and main condenser.

The SPU evaluation assumed the existing CWS pumps and air removal equipment were not modified and would continue to operate at the same flow rates.

9.7.3 Description of Analyses and Evaluations

Plant operation at the SPU conditions will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS to the Hudson River. The existing CWS pumps were not modified for the SPU and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River were not affected by the SPU, the CWS discharge temperature to the Hudson River increased. The SPU resulted in a higher flow of turbine exhaust steam to the condenser, which, in turn, increased the amount of

air and non-condensables needed to be removed from the condenser during plant operation. The air removal system was evaluated to verify that it is within original equipment capability.

The increases were evaluated considering the State Pollutant Discharge Elimination System (SPDES) Permit restrictions on discharge temperatures, discharge flow rates, and consent order flows.

The maximum pressure rise in the main condenser was found to result from a main steam dump following a 50-percent load rejection at the turbine while operating at the SPU power level. This abnormal operating condition maximized the incoming steam flow and heat load to the condenser. The potential for excessive vibration of the main condenser tubes and tube supports due to the worst case incoming steam was evaluated in accordance with the recommendations and methods of the Heat Exchange Institute (HEI).

9.7.4 Acceptance Criteria

The CWS design is considered acceptable to support SPU conditions, provided the following criteria are met:

- CWS pressure is bounded by system piping and component design.
- CWS temperature is bounded by system piping and component design and is within the SPDES limitations.
- CWS pumps provide the required flow to ensure condenser duty requirements are met.
- CWS discharge flows are within the SPDES limitations and consent order flows at SPU conditions.
- Remaining CWS equipment is adequate to support SPU conditions.

The main condenser design is considered acceptable to support SPU conditions, provided the following criteria are met:

- Main condenser thermal performance meets the increased heat loads and power output during SPU operation, as required by the SPU heat balances.
- Main condenser pressure with the maximum incoming steam flow and heat load at SPU conditions remains below the main turbine trip setpoint.

- Main condenser tubes and tube support design is adequate to prevent excessive tube vibration with the maximum incoming steam flow at SPU conditions.
- Main condenser auxiliary equipment is adequate to support SPU conditions.

The Condenser Air Removal System must be capable of removing all non-condensables, including air leakages and associated water vapor from the condenser shell, by maintaining a minimum steam condensing pressure. The Condenser Air Removal System is considered acceptable if the SPU requirements are bounded by the system and equipment design capability.

9.7.5 Design Criteria

The CWS provides cooling water for the main condenser of the turbine generator unit. As part of the CWS, the main condenser condenses and deaerates exhaust steam from the LP turbines, the steam dump system and the boiler feedpump turbine exhaust to maintain the required backpressure for improved plant efficiency. The CWS System is not safety related. Criterion required to meet SPU conditions are listed in the Acceptance Criteria above.

9.7.6 Results and Conclusions

The SPU evaluation confirmed that the existing CWS pumps provided sufficient flow for SPU heat removal and that the discharge temperature was within the SPDES limits. Main condenser duty, corresponding CWS discharge temperatures, steam flows, and condenser pressure increases due to SPU conditions were found to be within original design specifications.

The CWS pressure was not affected by operation at SPU conditions. No physical changes are being made to the CWS pumps, main condenser, piping, or auxiliary equipment. Therefore, none of the parameters that affect CWS pressure or inlet operating or design temperatures are affected by operation at SPU conditions.

The main condenser can accept the worst-case steam dump flow without exceeding the turbine trip setpoint and without experiencing excessive tube vibration. (See subsection 9.4.6 for additional discussion)

Other main condenser design factors including deaerating effects, tube cleanliness, tube-side velocity, and tube-side friction losses, will not be affected by SPU conditions.

The SJAEs meet the 1970 version of the HEI Standard. The SJAE capacity envelops the current plant recorded air and non-condensable gas in-leakage to the condenser with sufficient margin such that the SJAEs will operate satisfactorily under SPU conditions. The capability of the priming ejectors is not affected by the SPU since they operate only during plant startup.

9.8 Electrical Systems

9.8.1 AC and DC Plant Electrical Systems

The alternating-current (AC) and direct-current (DC) electrical distribution system and associated equipment were reviewed to evaluate the impact of the SPU on system and equipment performance, capacity and capability. Specifically, the following items were evaluated:

- Main generator
- Iso-Phase bus (IPB) duct
- Main transformers (MTs)
- Unit auxiliary transformer (UAT)
- Station auxiliary transformer (SAT)
- 6900-V power distribution system (including loads and cables)
- Protective relay schemes
- Miscellaneous systems (480-VAC, emergency diesel generators [EDGs], 118-VAC instrument supply systems, and 125-VDC systems)
- Grid stability

The system review also included an evaluation of the station load flow analysis, the station fault analysis, and grid stability studies. The purpose of the review was to determine if the electrical systems and equipment would operate satisfactorily and continue to perform their intended functions under SPU power levels. The results of the evaluation are described in the following sections.

9.8.1.1 Main Generator

9.8.1.1.1 Input Parameters and Assumptions

The main generator is a turbine-driven, hydrogen-cooled, four-pole machine-rated 1125.6 MVA, 22 kV, 0.90 power factor at 75-psig hydrogen pressure. The output of the main generator is

delivered to the low-voltage windings of the main transformers (MT31 and MT32) via the IPB duct. An IPB tap bus connects the main generator output to the UAT. Unit operation at SPU conditions will result in increased power output from the unit.

The scope of this review includes an evaluation of the main generator electrical parameters relevant to assessing equipment adequacy at SPU conditions. The review includes an evaluation of the generator operating at 75-psig hydrogen pressure, since this reflects the maximum capability of the machine.

Evaluation of the main generator is based upon the following inputs and assumptions:

- The main generator gross real power output at the reactor thermal power level of 3244 MWt is 1093.5 Mwe, based on a heat balance calculation.

- The value of 3244 MWt is based on a maximum calculated value of 3216 MWt with an additional 0.5-percent flow margin on the main steam supply.

- The value of 3216 MWt is the maximum calculated reactor thermal power given in the *IP3 Updated Final Safety Analysis Report* (UFSAR) (Reference 1), Table 10.2-3.

- The SPU will propose to license IP3 to a maximum calculated reactor thermal power of 3216 MWt, which corresponds to a calculated electrical output of 1093.5 MWe.

- The main generator can presently provide a rated output of 1125.6 MVA when operated from 0.90-lagging power factor up to and including unity (1.0) power factor at 75-psig hydrogen pressure. This capability has been evaluated and will remain the same at SPU.

- The main generator can presently provide a rated output of 1125.6 MVA when operated from 0.950-leading power factor up to and including unity (1.0) power factor at 75-psig hydrogen pressure. This capability has been evaluated in order to accommodate an output of 1093.5 MWe.. The capability has been limited to 1125.6 MVA when operated from 0.996-leading power factor up to and including unity (1.0) power factor at SPU. This reactive power limitation at leading power factor is due to stator core end packs.

- The main generator will operate within the constraints of the new generator capability curve at SPU.

- Generator real and reactive power output capacity at SPU will be determined from the new generator capability curve.

- The generator currently operates at 75-psig hydrogen pressure and will continue to operate at that pressure at SPU conditions.
- IP3 reactive power commitments credited for this SPU Program are 225-MVAR lagging and 100-MVAR leading.
- Generator reactive power requirements for normal power operation typically range from 200-MVAR lagging to 100-MVAR leading.

9.8.1.1.2 Description of Analysis and Evaluation

The nameplate rating of the main generator is 1125.6 MVA based on 75 psig hydrogen, 22 kV, 0.90 lagging power factor, three-phase, 60 Hz, 1800 rpm.

Evaluation of the main generator was based upon a comparison between the generator capability curve and the anticipated operating requirements when the machine operates at SPU conditions. Unit operation at leading and lagging power factor was considered.

9.8.1.1.3 Acceptance Criteria for Analysis

- Generator real power output capability (MW) does not limit turbine output capability at SPU.
- Generator reactive power requirements will not exceed 225-MVAR lagging, and 100-MVAR leading when the unit is operating at SPU conditions and 75-psig hydrogen pressure.

9.8.1.1.4 Evaluation

The main generator is one of the normal sources of power to the plant discussed in the IP3 UFSAR (Reference 1) Sections 8.1 and 8.1.1. The normal source of auxiliary power during plant operation is supplied from both IP3's main generator and offsite power. This SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU Program are 225-MVAR lagging and 100-MVAR leading. Operation of the generator at the proposed SPU is within the generator's capability curve. Increasing the generator output to 1093.5 MWe and operating the generator within the proposed reactive power limits does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions, assuming a single failure, has not been affected. The onsite and offsite power

systems will continue to meet the requirements of General Design Criteria-17 (GDC-17) (Reference 2) following implementation of the proposed SPU.

9.8.1.1.5 Results and Conclusions

The real power output (MW) capability of the main generator exceeds that required when the unit operates at SPU conditions. The generator capability curve shows that the machine is capable of continuous operation at an output of 1013 MW (0.90-lagging power factor) up to and including 1125.6 MW (unity power factor) at 75-psig hydrogen pressure. Maximum required unit output at SPU is 1093.5 MWe. Therefore, the real power output (MW) capability of the main generator is significantly higher than the real power output required at SPU.

The reactive power capability (MVAR) of the main generator from the generator capability curve is 267-MVAR lagging at 75-psig hydrogen pressure when the unit operates at maximum evaluated reactor thermal power. Machine operation at the specified values (1093.5 MW and 267 MVAR) corresponds to a generator lagging power factor of 0.971. Machine leading reactive power capability is 124 MVAR at 75-psig hydrogen pressure when the unit operates at maximum evaluated reactor thermal power. Machine operation at the specified values (1093.5 MW and 124 MVAR) corresponds to a generator leading power factor of 0.993.

The reactive capability of the main generator meets or exceeds the normal power requirement of 200-MVAR lagging and 100-MVAR leading and the IP3 reactive power commitments credited for this SPU of 225-MVAR lagging and 100-MVAR leading at 75-psig hydrogen pressure. The main generator provides these reactive power requirements at SPU conditions.

A review of the generator capability curve confirms that the main generator will support unit operation at SPU load conditions. Additionally, the main generator will support credited agreements regarding machine leading and lagging reactive power requirements.

9.8.1.2 Iso-Phase Bus Duct

9.8.1.2.1 Input Parameters and Assumptions

The output of the main generator is delivered to the low-voltage windings of the main transformers (MTs) (MT31 and MT32) via the IPB duct. An IPB tap bus connects the main generator output to the UAT. Unit operation at SPU conditions will result in increased power output from the unit and an attendant increase in MT and UAT loading. Accordingly, the IPB main and tap bus conductor current will also increase.

The scope of this review includes an evaluation of IPB electrical parameters relevant to assessing equipment adequacy at SPU conditions and at maximum reactor thermal power.

Evaluation of the IPB is based upon the following inputs and assumptions:

- The IPB 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. The segment from the generator has a forced air-cooled rating of 32 kA at 23 kV, 65°C rise. The next segments of the main bus that run from the split to each MT have forced air-cooled rating of 16 kA at 23 kV, 65°C rise. The remaining segment runs from MT32 to the UAT. This tap segment has a self-cooled rating of 1.5 kA at 23 kV. This segment does not have a forced air-cooled rating.

- The transformer test reports show that the two MTs have identical MVA ratings but different impedances. Since the current splits differently between the transformers in proportion to the impedance, current to each MT primary winding will be slightly different.

- The highest IPB loading will occur when the house loads are fed from the UAT. The 16-kA portion of the bus between the MT split and UAT tap is the most limiting since it carries the generator output to one MT plus the UAT load.

- The highest IPB loading will occur when the generator is operating at minimum voltage and maximum generator output. Generator operation was evaluated within a voltage range of ±5 percent from nominal rated voltage.

- The generator is assumed to be operating at 75-psig hydrogen pressure.

Fault current at the IPB is a function of equipment parameters associated with the main generator, MT, auxiliary transformer, etc. Since SPU did not change any relevant equipment parameters, it is assumed that unit operation at SPU will not adversely affect IPB fault duty.

9.8.1.2.2 Description of Analysis and Evaluation

Evaluation of the IPB main and tap buses was based upon a comparison between the maximum anticipated full-load current and the design ratings of the main and tap bus conductors with the generator operating at both lagging and leading power factor. This evaluation is based on house loads being fed from the UAT, since this results in the worst-case IPB loading. Since the IPB main and tap bus short circuit design ratings were adequate prior to SPU and SPU did not adversely affect IPB fault current levels, the IPB main and tap bus short circuit design ratings are adequate for SPU.

9.8.1.2.3 Unit Operation at Lagging Power Factor

The generator capability curve was reviewed to identify gross generator output when the unit operates at SPU conditions with main generator operation at lagging power factor.

Table 9.8-1 shows the IPB loading with the generator operating at the SPU power level, lagging power factor (75-psig hydrogen), and at maximum reactor thermal power.

9.8.1.2.4 Unit Operation at Leading Power Factor

The generator reactive capability curve was reviewed to identify the gross generator output when the unit operates at SPU load conditions with the main generator operation at leading power factor.

Table 9.8-2 shows the IPB loading with the generator operating at the power SPU level, leading power factor (75-psig hydrogen), and at maximum reactor thermal power.

9.8.1.2.5 Tap Bus

Maximum anticipated full-load current for the tap buses results when the connected UAT operates at maximum output load conditions. Based on a review of calculated transformer loading included in the applicable station load flow analysis, the maximum UAT loading occurs when the station is operating at maximum full-load conditions. The calculated UAT loading is identified in Table 9.8-3. The resulting tap bus currents are shown in Tables 9.8-1 and 9.8-2.

9.8.1.2.6 Acceptance Criteria for Analysis

- The continuous current rating of the IPB main bus is equal to or greater than the required IPB bus ampacity at maximum generator output (MVA) and minimum generator voltage (0.95 pu).

- The continuous current rating of the IPB tap bus is equal to or greater than the required bus ampacity at maximum UAT loading.

- Short circuit current ratings of the IPB main and tap buses are equal to or greater than the calculated available fault current at SPU conditions.

9.8.1.2.7 Evaluation

The IPB duct is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.1.1. For Phase 1 SPU (1080 MWe, 225-MVAR lagging and 100-MVAR leading), the IPB is capable of operating within its ratings. The Phase 2 SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU project are 225-MVAR lagging and 100-MVAR leading. Increasing the generator output to 1093.5 MWe and operating the generator within the proposed reactive power limits causes the IPB duct to operate slightly outside its ratings. This load exceedance occurs only during extreme system grid conditions and is controlled by reactive power limits and can be permanently addressed with future Phase 2 modifications to the IPB.

The increased power flow through the IPB duct does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.2.8 Results and Conclusions

IPB Main Bus (32 and 16 kA sections)

The continuous current rating of the IPB main bus exceeds the anticipated worst-case bus loading for maximum proposed SPU generator output (MWe) and maximum required reactive power (MVAR) except as described below (see Tables 9.8-1 and 9.8-2).

However, when operating the generator at 0.95 pu voltage during the maximum analyzed reactor thermal power and maximum generator reactive power capability (1093.5 MWe, 267-MVAR lag), the 16-kA section of IPB feeding the MT32 and UAT exceeds the IPB rating (16.183-kA operating, 16.0-kA rated).

Since the IPB main bus short circuit design ratings were adequate prior to SPU, and SPU did not adversely affect available fault current levels, the IPB main bus short circuit design ratings are considered adequate for SPU.

IPB Tap Bus (1.5 kA section)

The continuous current rating of the IPB tap bus exceeds the anticipated worst-case bus loading at SPU with substantial margin (that is, 1500 amps versus 1328 amps, see Table 9.8-1).

Since the IPB tap bus short circuit design ratings were adequate prior to SPU, and SPU did not adversely affect available fault current levels, the IPB tap bus short circuit design ratings are considered adequate for SPU.

9.8.1.3 Main Transformers

9.8.1.3.1 Input Parameters and Assumptions

The MTs provide the interface between the main generator and the power system grid. Main generator output power is delivered to the primary windings of the MT at 22 kV nominal. The MT steps up generator output to 345 kV nominal and delivers the output to the 345-kV switchyard. Unit operation at SPU conditions will result in an attendant increase in MT output loading.

The scope of this review includes an evaluation of MT capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU. The review also includes an evaluation of remaining transformer life expectancy and existing MT cooler capacity.

Evaluation of the MT is based upon the following inputs and assumptions:

- The main generator real power output is 1093.5 MWe during maximum analyzed reactor thermal power of 3216 MWt.
- The generator is assumed to be operating at 75-psig hydrogen pressure.
- The MT will be evaluated using generator reactive power capabilities of 267-MVAR lagging and 124-MVAR leading. These are reactive power capabilities at 1093.5 MWe.
- The unit auxiliary system (house) load will be supplied from the main generator via the UAT and from offsite via the SAT. This is consistent with the normal plant configuration when the unit is operating at full power.
- The load to the UAT is assumed to be 48 MVA at 0.84-lagging power factor based on a review of the normal load flow runs. This includes the distribution system increase in load due to this SPU (Table 9.8-3).

9.8.1.3.2 Description of Analysis and Evaluation

The MT consists of two half-sized generator step-up transformers MT31 and MT32. The nameplate rating for each transformer is 542/607 MVA FOA @ 55°/65°C rise, 20.3 kV primary, 345 kV secondary, three-phase, 60 Hz. MT31 is manufactured by Westinghouse and has been in operation since 1976. MT32 is manufactured by General Electric and has been in operation since 1983.

Evaluation of the MT was based upon a comparison between the applicable transformer design ratings and the anticipated operating requirements when the unit operates at SPU conditions. Unit operation at leading and lagging power factor conditions was considered assuming the main generator operates within the limits previously identified.

9.8.1.3.3 Main Transformer Loading

MT loading at SPU is determined in Tables 9.8-4 and 9.8-5 assuming house loads are supplied either from the UAT or offsite power sources and the main generator real and reactive power requirements previously identified in Section 9.8.1.3.1..

MT loading determined in Table 9.8-4 assumes house loads are supplied from the main generator via the UAT consistent with the normal plant configuration when the unit is operating at full power. Plant operating scenarios, evaluated using load flow analysis, assume the house loads are either supplied from the main generator via the UAT and from offsite via the SAT or completely from offsite power sources via the SAT. Each MT has adequate capacity to support unit operation at proposed SPU conditions even if the house loads are supplied entirely from the SAT. Table 9.8-5 shows that at maximum proposed SPU reactor thermal power, corresponding to 1093.5 MWe and 124-MVAR leading, results in maximum MT loading. Each transformer will operate above its 542-MVA, 55°C rating but below the maximum rating of 607-MVA, 65°C rating.

9.8.1.3.4 Acceptance Criteria for Analysis

MT nameplate ratings of 542/607 MVA FOA @ 55°/65°C rise each will not limit unit operation at SPU conditions.

9.8.1.3.5 Evaluation

The MTs are part of the onsite power system discussed in the IP3 UFSAR Section 8.1.1 (Reference 1). The normal source of auxiliary power during plant operation is supplied from both IP3's main generator and offsite power. The main transformers analyzed in this evaluation

connect the main generator, offsite power system, and IP3 distribution system. This SPU increases the main generator's electrical output to 1093.5 MWe. IP3 reactive power commitments credited for this SPU program are 225-MVAR lagging and 100-MVAR leading. Increasing the generator output to 1080 MWe and operating the generator within the proposed reactive power limits does not cause the MTs to operate outside their ratings. The increased power flow through the MTs does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.3.6 Results and Conclusions

The maximum calculated load for the parallel MTs is 1098 MVA with house load supplied from UAT (see Table 9.8-4). The maximum calculated load for the parallel MTs is 1132 MVA with house load supplied from the offsite power source (see Table 9.8-5). The parallel MT's maximum rating is 1214 MVA at 65°C temperature rise over ambient.

The preceding evaluation confirms that the existing MT nameplate ratings are adequate to support unit operation at SPU conditions when the main generator is operated in accordance with the assumptions previously identified. It is also reasonable to conclude that each MT is adequately sized at its 65°C rating to support unit operation at SPU even if the SAT supplies the entire house load.

9.8.1.4 Unit Auxiliary Transformer

9.8.1.4.1 Input Parameters and Assumptions

Power required for station auxiliaries during normal operation is split between the UAT and the SAT. Power to the auxiliaries (house loads) on 6900-V buses 1 through 4 is supplied by the UAT, which is connected to the main generator via the IPB duct. Unit operation at SPU conditions will result in a slight increase in UAT output loading because the net brake horsepower (bhp) required by several large pump motor drives supplied from 6900-V buses 1 through 4 will increase due to proposed SPU operation.

The scope of this review included an evaluation of UAT design capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU.

Evaluation of the UAT is based upon the following inputs and assumptions:

- The house load is shared between the UAT and the SAT. This is consistent with the normal plant configuration when the unit is operating at full power.
- IP3 load flow analysis will be used to evaluate the effect of SPU on the electrical distribution system.

9.8.1.4.2 Description of Analysis and Evaluation

The nameplate rating for the UAT is 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise, 22 kV primary, 6900 V secondary winding, three-phase, 60 Hz. The secondary winding supplies power directly to downstream 6900-V buses 1 through 4. The UAT primary is equipped with an automatic load tap changer that regulates voltage to a preset value at the downstream 6900-V normal buses.

9.8.1.4.3 UAT Loading

The station load flow analysis was reviewed to identify maximum calculated UAT loading. The analysis determined UAT loading during normal operation (full-load), hot-shutdown (start-up), cold-shutdown, condensate polisher building, large-break loss-of-coolant accident (LBLOCA), and steam breaks. Review of the calculated results confirmed that worst-case UAT loading occurs during normal operation (full-load). This case was used to evaluate the effect of SPU on the UAT.

The existing IP3 load flow analysis was used as the baseline to evaluate the effect of SPU on the UAT for full-load conditions. The incremental changes in loading due to SPU were added to the baseline and the resulting values were compared to the UAT rating to determine the equipment adequacy for SPU. The incremental changes in loading due to SPU are summarized in Table 9.8-6.

9.8.1.4.4 Acceptance Criteria

UAT nameplate rating of 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise will not limit unit operation at SPU conditions.

9.8.1.4.5 Evaluation

The UAT is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. Although the proposed SPU causes a slight increase in loading on the UAT, the

UAT operation remains within its 48.16 MVA FOA @ 65°C rise rating. The increased power flow through the UAT does not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.4.6 Results and Conclusions

The worst-case total secondary load on the UAT is 44.563 MVA (Table 9.8-6), which is slightly greater than the UAT maximum nameplate rating of 43.00 MVA FOA @ 55°C rise but less than the nameplate rating of 48.16 MVA FOA @ 65°C rise. Accordingly, it is reasonable to conclude that the transformer temperature rise will be within the design ratings and the transformer coolers will be operating within their design capacity when the unit operates at SPU.

The UAT has adequate capacity to support unit operation at SPU conditions, and based on the transformer condition, the UAT will require no modifications to the cooling system to meet SPU conditions.

9.8.1.5 Station Auxiliary Transformer

9.8.1.5.1 Input Parameters and Assumptions

A single SAT serves IP3. Offsite power from the 138-kV switchyard is supplied to the 6900-V buses via the SAT during normal operation, plant start-up, outage, and design bases accident (DBA) conditions. Power required for station auxiliaries (house loads) during normal operation is split between the UAT and the SAT, with house loads on 6900-V buses 5 and 6 supplied by the SAT, which is connected to the 138-kV switchyard via overhead lines. On a unit trip, a transfer scheme ties buses 1 and 2 to bus 5, and buses 3 and 4 to bus 6.

The scope of this review included an evaluation of SAT design capacity based upon a comparison between transformer nameplate rating and the maximum transformer loading at SPU.

The evaluation of the SAT is based upon the following inputs and assumptions:

- The normal source of auxiliary power for 6900-V buses 5 and 6, and standby power required during plant startup, shutdown, and after reactor trip is the SAT.

- The existing IP3 load flow analysis will be used to evaluate the effect of SPU on the electrical distribution system.

- Unit operation at SPU conditions will result in an actual increase in SAT output loading when the house loads are transferred, because the net bhp required by several large pump motor drives supplied from 6900-V buses 1 through 4 will increase due to power SPU. However, the existing load flow calculation has modeled some of the 6.9-kV loads conservatively high. The new KW and KVAR values for the affected motors are based on the actual calculated bhps. Some of the loads have increased, but others have decreased. When UAT loads are transferred to the SAT during certain operating conditions, certain loads are turned off. Analysis of the loads shows a calculated net decrease to the load flow. Therefore, although the actual 6600-V motor bhp requirements have increased, the calculated net effect is a decrease in overall SAT loading based on load flow model calculations.

- Incremental load changes in the 480-V system have not been included in this SAT analysis since conservatism in the existing load flow model bounds any increase in 480-V system loading.

9.8.1.5.2 Description of Analysis and Evaluation

The nameplate rating for the SAT is 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise, 138 kV primary, 6900 V secondary winding, three-phase, 60 Hz. The secondary winding supplies power directly to downstream 6900-V buses 5 and 6. The SAT secondary is equipped with an automatic load tap changer that regulates voltage to a preset value at the downstream 6900-V buses.

9.8.1.5.3 SAT Loading

The IP3 load flow analysis was reviewed to identify maximum calculated SAT loading. The analysis determined SAT loading during normal operation (full-load), hot-shutdown (start-up), cold-shutdown, condensate polisher building, LBLOCA, and steam breaks. Review of the calculated results showed that worst-case steady-state SAT loading occurs during a steam break event with phase B isolation and buses 2A and/or 3A not available.

A baseline for transformer loading was developed using the values in the existing IP3 load flow analysis. The incremental changes in loading due to SPU were added to the baseline and the resulting values were compared to the SAT rating to determine the equipment adequacy for SPU.

The loading on buses 5A and 6A is conservative in the existing IP3 load flow analysis (bus 5A is 731-kVA high, bus 6A is 1788-kVA high). Overall, the existing IP3 load flow analysis has over 7300 kVA of conservatism on buses 2A, 3A, 5A, and 6A. For this reason, any incremental load changes in the 480-V system were not included in this SAT analysis and are bounded by the existing SAT loading analysis.

9.8.1.5.4 Acceptance Criteria for Analysis

SAT nameplate rating of 43.00 MVA FOA @ 55°C rise and 48.16 MVA FOA @ 65°C rise will not limit unit operation at SPU conditions.

9.8.1.5.5 Evaluation

The SAT is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. The changes in power flow through the SAT during the analyzed accident events do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.5.6 Results and Conclusions

The highest postulated load on the SAT is during a steam break accident. During this event, the total secondary load on the SAT at SPU is calculated to be 49.295 MVA (Table 9.8-7), which is less than the existing modeled load of 49.309 MVA (Table 9.8-8). However, there is conservatism in the existing load flow analysis. Buses 5A and 6A alone include a total of about 2.5 MVA of excess load. Therefore, the existing load on the SAT during peak accident conditions would be decreased to 46.809 MVA and the new SAT load at SPU would be decreased to 46.795 MVA. In both cases, the total SAT load is less than the SAT rating of 48.16 MVA @ 65°C. If the entire 7.3 MVA of approximated excess load on buses 2A, 3A, 5A, and 6A was subtracted from the calculated load flow results, the existing SAT load would be 42.009 MVA and at SPU would be 41.995 MVA. Both are less than the SAT rating of 43.00 MVA @ 55°C.

The normal loading on the SAT at SPU is 8.588 MVA (Table 9.8-7), which is a continuous operating condition. Accordingly, it is reasonable to conclude that the transformer temperature rise will be within the design ratings and the transformer coolers will be operating within their design capacity when the unit operates at SPU.

The SAT has adequate capacity to support unit operation at SPU conditions based on the analyzed normal and accident loading conditions. The incremental BHP changes due to SPU cause a reduction in modeled loading on the SAT. Based on the transformer condition, the SAT will require no modifications to the cooling system to meet SPU conditions.

9.8.1.6 Medium-Voltage, 6900-V System

9.8.1.6.1 Input Parameters and Assumptions

The 6900-V system supplies power for the majority of the safety- and non-safety-related (AC) loads. Large station loads are supplied directly from the system. Smaller low-voltage AC loads (480 V and below) are also supplied from the system via appropriately rated step-down transformers. During normal full-load operation, the system is supplied power from the UAT, and the SAT, with buses 1 through 4 supplied by the UAT, and buses 5 and 6 supplied by the SAT. During plant start-up, shutdown, outage, and plant-accident conditions the system is supplied from the SAT.

Unit operation at SPU conditions will result in increased fluid system flow requirements that will, in turn, increase the bhp load on several medium-voltage pump motor drives supplied from the 6900-V buses. The 6900-V non-segregated phase bus, switchgear, medium-voltage motors, and associated feeder cables affected by SPU are discussed in this section.

The scope of this review included an evaluation of the 6900-V system to confirm adequacy of the applicable switchgear ratings and to confirm that bus voltage levels are adequate to support equipment operation and function when the unit operates at SPU conditions. The review also included an evaluation of motor load requirements at SPU conditions to verify that the affected pump motor drives and associated feeder cables will operate within their rated capability.

Evaluation of the 6900-V system was based on the following inputs and assumptions:

- Loading from the existing station load flow analysis together with incremental changes in loading calculated in the bhp calculation and RCP motor evaluation due to SPU are used to develop the evaluation model.

- Revised load bhp data for balance-of-plant (BOP) 6900-V motor driven pumps is based upon analysis at a reactor thermal power level of 3244 MWt, which is maximum reactor thermal power plus 0.5-percent steam flow rate margin. This analysis determined condensate pumps (CPs), condensate booster pumps (CBPs), and heater drain pumps (HDs) bhp requirements at SPU.

- Revised bhp data for the reactor coolant pumps (RCPs) for SPU conditions
- Cable ampacities are taken from IP3 short-circuit calculations.
- The highest loading for buses 1, 2, 3, and 4 is during normal full-load operation conditions while supplied from the UAT.
- The highest loading for buses 5 and 6 is during a steam break event where loads from buses 1 and 2 are supplied by bus 5 and loads from buses 3 and 4 are supplied by bus 6.

9.8.1.6.2 Description of Analysis and Evaluation

The effect of power operation at SPU on the 6900-V non-segregated phase bus, switchgear buses and breakers, station bus voltage levels, and the 6600-V pump motor drives and associated feeder cables are discussed separately below.

9.8.1.6.3 6900-V Switchgear

The evaluation of the 6900-V non-segregated phase bus, switchgear buses, and breakers was based upon a comparison between the applicable equipment ratings and the anticipated operating requirements at SPU conditions, as determined in the existing IP3 load flow and evaluation model. The continuous current design ratings of the 6900-V non-segregated phase bus, switchgear, and switchgear breakers are potentially affected by unit operation at SPU because of the attendant increase in electrical load flow throughout the system. Conversely, 6900-V equipment short-circuit duty is not expected to be adversely affected because unit operation at SPU conditions does not require any equipment changes, replacements, and/or new installations that could increase the fault current duty at the 6900-V level. Since no new 6900-V loads were added as a part of SPU, the existing switchgear physical arrangement remains unchanged.

6900-V Bus Incoming Supply and Motor Feeder Breaker Continuous Current Ratings

IP3 load flow analysis was reviewed to identify the maximum calculated steady state loading for the 6900-V incoming supply breakers. The analysis determined equipment loading during maximum normal full-load, DBA, and outage load conditions with either the UAT and/or the SAT, as applicable, supplying power for the house loads. Review of the calculated results confirmed that worst-case loading on buses 1, 2, 3, and 4 occurs during normal operation and that worst-case steady-state loading occurs on buses 5 and 6 during a steam break event, where all auxiliary loads on buses 1, 2, 3, and 4 are transferred to the SAT. The incremental

loading is combined with the existing loading, and the resulting bus loading is summarized in Table 9.8-9.

A comparison between the expected SPU load conditions, as determined in this evaluation, and the continuous current ratings of the switchgear incoming supply breakers is also provided in Table 9.8-9. Note that the non-segregated bus comprises of segments with ratings of 4000A, 2000A, and 1200A as shown on the 6900-V single-line diagram. The non-segregated bus loading is also provided in Table 9.8-9.

A comparison between the maximum continuous current load at SPU and the design rating of the affected motor feeder breakers is shown in Table 9.8-10. The motor load current was taken from Table 9.8-11.

6900-V Equipment Fault Current Ratings

Short-circuit duty is not adversely affected by equipment load changes associated with unit operation at SPU conditions. This is because the load changes did not require replacement of, or changes to, existing electrical components and equipment (for example, motor drives, power transformers, and feeder cables) that could result in increased equipment fault current duty at the 6900-V buses.

9.8.1.6.4 Medium-Voltage (6600-V) Motors and Motor Feeder Cables

6600-V Motors

Unit operation at SPU conditions will result in a bhp load change on several 6600-V motor-driven pumps. Specifically, the CP, CBP, HP, and RCP motors, all of which are supplied from the 6900-V switchgear buses, will each experience a load change. Evaluation of each affected motor drive was based upon a comparison between the motor nameplate rating (HP) and the required motor bhp at SPU flow conditions. It should be noted that the CP 31, RCPs 31, 32, 33, and 34, and HD 31 motors have been calculated to operate at a bhp during SPU that is less than the presently modeled bhp shown in the current load flow analysis. A summary of the motor nameplate ratings (HP) and SPU bhp data is shown in Table 9.8-12.

All affected BOP motor drives will be operating at less than nameplate rating when the unit operates at SPU.

6600-V Motor Feeder Cables Including the RCP Electrical Penetrations

The existing motor feeder cables were evaluated to confirm that cable ampacity was equal to or greater than motor load current when the associated motor operates at SPU load conditions. The comparison between feeder cable ampacity and motor load current was developed at SPU was developed and shown in Table 9.8-11.

Evaluation of the electrical penetrations associated with the RCP motor feeders was based upon a comparison between motor load current during cold- and hot-loop operation and penetration rated ampacity. Cold-loop values bound normal operating (hot-loop) load current. The penetrations associated with the RCP motor feeders consist of two feed-through conductors per phase each rated 315 amps, continuous, for a total ampacity of 630 amps. RCP motor load current under cold loop conditions, adjusted for motor operation at 90-percent rated voltage, results in motor load current of 634 amps (317 amps/penetration conductor). Although the required ampacity is slightly greater than the rated penetration ampacity, the penetrations are considered adequate since this is a short-time condition and is not continuous. Also, if the actual motor voltage was 91 percent of rated, the load current would be 627 amps, which is within the rated ampacity of the cables. Since cold-loop operation only occurs during startup, where 6600-V motors are operated well above 90 percent of rated voltage, these cables should always operate well within their rated ampacity. Furthermore, the RCPs will be operating at SPU below their existing nameplate horsepower ratings.

9.8.1.6.5 System Voltage Levels

The existing IP3 load flow calculation analyzed a number of load flow (steady-state) scenarios. These included full-load, hot-shutdown (start-up), cold-shutdown, condensate polisher building, large LBLOCA, and steam break conditions. It was determine that the largest loading on the UAT and SAT during normal-operation conditions was at full load.

It was also determined that a steam break event with bus 2A and/or 3A not available had the greatest loading on the SAT.

The estimated bus and motor terminal voltages during normal and accident conditions were evaluated to determine the extent of impact on the 6900-V system. The evaluation, using load flow analysis, shows a worst-case voltage reduction at the 6900-V system level at SPU to be about 1 volt in the system model.

9.8.1.6.6 Acceptance Criteria

For the 6900-V system to be considered acceptable, unit operation at SPU conditions will result in:

- Continuous current or fault current requirements that do not exceed the applicable design ratings of the 6900-V switchgear or circuit breakers.
- Operation of 6600-V motors at loads less than or equal to rated motor horsepower.
- Load current requirements that do not exceed motor feeder cable ampacity or result in excessive cable voltage drop.
- Minimum voltage levels at the 480-V buses that are greater than the voltage required to reset the degraded voltage relays.
- Protective relay requirements that do not exceed the capability of the 6900-V system electrical protection schemes (refer to subsection 9.8.1.7 of this report).

9.8.1.6.7 Evaluation

The 6900-V system is part of the onsite power system discussed in the IP3 UFSAR (Reference 1) Section 8.2.2. The changes to motor loads in the 6900-V system do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.6.8 Results and Conclusions

9.8.1.6.8.1 6900-V Switchgear

The continuous current design ratings of the 6900-V switchgear incoming supply breakers and buses and the affected motor feeder breakers exceed the SPU load requirement during steady-state normal-loading conditions. However, bus 5 load exceeds its rating during a steam break event peak loading based on the existing load flow model. This bus loading is not considered a continuous operating condition. The SPU bhp changes have increased bus 5 current by only 3 A, from 2099 A to 2102 A, during this accident event. The change is considered insignificant compared to the overall bus 5 load that already existed. Furthermore, removing the

conservatism from the 480-V system loading would bring bus 5 well within its continuous rating during a peak accident condition.

Short circuit duty is not adversely affected by equipment load changes associated with unit operation at SPU conditions, because the load changes did not require replacement of, or changes to, existing electrical components and equipment.

9.8.1.6.8.2 6600-V Motors

All affected 6600-V motor drives will operate at less than nameplate rating HP when the associated systems are operating at SPU conditions.

9.8.1.6.8.3 6600-V Motor Feeder Cables Including RCP Electrical Penetrations

The ampacity of the existing 6600-V motor feeder cables exceed the motor load current required when the associated motors operate at normal SPU load conditions (Table 9.8-11). However, the RCP loading exceeds the cable ampacity during cold-loop operating conditions (Table 9.8-11) with terminal voltage at 90 percent of rated voltage. Although the cold-loop current drawn by the RCP marginally exceeds the cable ampacity, this is considered acceptable, that is, ampacity is exceeded by 0.63 percent. The RCP cold-loop current is not continuous and its hot-loop current is less than the cable continuous ampacity. Also, the analyzed load flow cases show the RCP terminal voltages to be well above 90 percent of rated voltage, bringing the RCP load current within the cable ratings.

9.8.1.6.8.4 6900-V System Voltage

The worst-case reduction of 6900-V system voltage levels as a result of SPU is approximately 1 volt (0.01 percent difference). All bus voltages are above 98 percent of their nominal operating voltage. Also, all motor terminal voltages are above 102 percent of their rated voltage. Therefore, the SPU does not significantly change the analyzed operating voltages. Also, the changes in the 6900-V system do not affect the 480-V bus voltages. Therefore, the degraded grid voltage (DGV) relay settings are not affected.

9.8.1.6.8.5 6600-V Motor Protective Relays

6600-V motor protective relays are discussed in subsection 9.8.1.7.4 of this report.

9.8.1.7 Protective Relay Schemes

9.8.1.7.1 Input Parameters and Assumptions

Plant electrical equipment is provided with protective relay schemes designed to prevent or minimize equipment damage and to limit equipment outages to the immediately involved equipment or component during system disturbances. Protective relay schemes associated with systems affected by SPU may, in turn, be affected because of the change in the protected equipment operating point. Accordingly, the scope of this review is limited to an evaluation of affected equipment protection schemes.

The evaluation of the protective relay schemes was based, in part, on the following inputs and assumptions:

- IP3 electrical system description – high voltage
- IP3 electrical system description – medium voltage
- IP3 overall unit protection system description
- Power distribution bus arrangement as shown on the one-line diagrams
- IP3 relay setting calculations
- IP3 design basis document – 480-V electrical distribution system

9.8.1.7.2 Description of Analysis and Evaluation

Protective relay schemes for the main generator, MTs, UATs, and SATs, and those medium-voltage motors affected by SPU were reviewed to evaluate the effects of unit operation at SPU conditions.

9.8.1.7.3 Unit Equipment Protection

Entergy maintains the existing unit equipment protection schemes and associated setpoints. A review was conducted and has confirmed that the schemes and the associated setpoints were unaffected for operation under SPU conditions. The following paragraphs summarize the protective relay scheme review.

Main Generator Protection

The applied main generator protection schemes are intended to limit machine damage for internal fault conditions and to prevent machine damage during abnormal operating or external fault conditions. To accomplish this basic design requirement, the primary and backup generator protection systems are designed to trip the generator and associated feeder breakers

for faults that may result in abnormally high currents flowing through the windings of the generator, MTs, or the UAT. A trip signal acts to simultaneously open the generator output breakers (at Buchanan Substation), and open the field supply breaker at the unit. The IP3 main generator is tripped via primary and backup lockout relays, actuated primarily in response to the following parameters:

Primary Protection:

- Generator differential
- MT31 differential
- MT32 differential
- Generator neutral ground overcurrent
- UAT lockout signal
- Turbine trip

Backup Protection (additional functions):

- Generator/MT differential
- Loss of excitation (field)
- Negative sequence
- Backup generator ground

A review of one-line diagrams and the electrical system description confirms that the applied schemes are dependent upon machine ratings, machine design parameters, and the design of the connected system. These schemes are not affected by machine operation at SPU conditions. For example, overlapping differential schemes provide machine protection for both internal (generator differential and unit differential schemes) and external (unit differential scheme) phase fault conditions. The schemes are not affected by load changes within the rated operating range of the generator. Ground fault protection schemes, provided by ground over-voltage relays, are designed and set based upon the system grounding design, and is independent of main generator output. Loss-of-excitation and negative-sequence protection schemes that are included among the remaining main generator protection schemes are similarly unaffected by unit operation at SPU conditions because the machine will be operated within its rated capability.

MT, UAT, and SAT

A review of one-line diagrams, high voltage, and medium-voltage electrical system descriptions, overall unit protection system descriptions, and the relay setting calculation indicates that transformer protection essentially consists of high-speed phase fault protection and ground fault protection.

<u>Main Transformers (MT31 and MT32)</u>

Primary protection of each of the two half-size MTs is provided by three dedicated differential relays. Actuation of either of the differential relays will initiate a generator trip by tripping the primary lockout relay. Back-up protection is provided by three unit differential relays. Both MT secondary windings are 'wye' connected with a grounded neutral leg, each of which is monitored by a current transformer connected to a single neutral ground relay. Actuation of the backup differential and the neutral ground overcurrent will initiate a generator trip by tripping the unit lockout relay. Primary protection CT selection and relay setting are based on maximum MT nameplate rating of 607,040 KVA each (at 65°C temp rise). Backup protection CT selection and relay setting are based on the maximum generator rating of 1,125,600 KVA.

<u>Unit Auxiliary Transformer</u>

The UAT is protected by a dedicated differential relay scheme and three single-phase time overcurrent protection relay scheme for internal phase and ground faults as well as faults within the 6900-V bus sections fed by the transformer. A neutral time overcurrent relay provides ground fault protection to the low voltage winding. Back-up protection is also provided by these unit auxiliary transformer protective relay schemes. CT selection and differential relay setting are based on the maximum UAT rating of 48,160 KVA (FOA @ 65°C temp rise), and the overcurrent relay protection is based on allowing operation of the UAT at 30 percent above its 65°C FOA rating.

<u>Station Auxiliary Transformer</u>

The SAT is protected by a differential relay scheme. Back-up protection is provided by three single-phase overcurrent relays and a ground overcurrent relay. CT selection and differential relay setting are based on the maximum SAT rating of 48,160 KVA (FOA at 65°C temp rise), and the overcurrent relay protection is based on allowing operation of the SAT at 30 percent above its 65°C FOA rating.

Conclusion

Since the existing power transformers (MT31, MT32, UAT, and SAT) will continue in service and operate within their nameplate ratings, the existing electrical protection schemes described above are unaffected when the unit operates at SPU conditions.

9.8.1.7.4 Medium-Voltage Motor Protection

The purpose of the medium-voltage motor and motor feeder protection scheme is to provide electrical protection against the damaging effects of sustained overload, locked rotor, and phase and ground fault conditions. For example, instantaneous overcurrent relays provide phase and ground fault protection, while time overcurrent relays provide motor overload protection. The protection scheme also incorporates thermal overload relays as applicable.

Design of the applied motor protective relay schemes (including setpoints) is based upon motor nameplate ratings, motor design parameters, and feeder ratings. The BOP motors affected by the SPU are listed in Table 9.8-12 of this engineering report.

Since the subject motors will be operated within their respective nameplate rated capabilities, and because none of the affected motor drives will be replaced, operation at SPU conditions will not affect the existing BOP medium-voltage motor protection schemes and setpoints.

9.8.1.7.5 Emergency Diesel Generator

Loading associated with the 480-V EDGs is bounded by operation at SPU conditions as described in subsection 9.8.1.8.2.3 of this report. Since no new EDG-related loads or other changes have been identified, the existing EDG electrical protection schemes and setpoints are similarly unaffected.

9.8.1.7.6 Acceptance Criteria for Analysis

Protective relay schemes and associated setpoints shall not constrain equipment operation at SPU load conditions.

9.8.1.7.7 Evaluation

The protective relays discussed in this report affect the operation of onsite power system equipment described in the IP3 UFSAR (Reference 1) Sections 8.1, 8.1.1, 8.2.1, 8.2.2, and 8.2.3. Review of the protective relaying calculations shows that no changes are required to the existing protective relay settings, since all equipment is operated within previously analyzed

constraints used to set the protective devices. There are no changes to the control circuits, power circuits, or auxiliary support systems and features that support safety-related loads. The changes due to this SPU do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.7.8 Results and Conclusions

The review determined that unit equipment protection schemes (that is, main generator, MTs, UAT, and the SAT), as well as the protective relay schemes associated with the 6900-V equipment are adequate as installed, and that they provide adequate margin to permit unit operation at SPU power levels.

The review concluded that the protection schemes are considered adequate for use at SPU.

9.8.1.8 Miscellaneous Systems

9.8.1.8.1 Input Parameters and Assumptions

This section includes evaluations of various electrical power distribution systems that are either not impacted, or are marginally impacted by SPU. The systems include:

- 480-V system
- 13.8-kV system
- EDG system
- 118-VAC instrument supply system
- 125-VDC system

Relevant inputs and assumptions are identified within the evaluation discussion for the applicable system.

9.8.1.8.2 Description of Analysis and Evaluation

9.8.1.8.2.1 480-V System

The 480-V power distribution system consists of seven bus sections designated 2A, 3A, 5A, 6A, 312, 313, and 3NGY01. Bus sections 5A, 6A, and 2A and 3A are the 480-V safeguard buses, while 312 and 313 supply power to non-safety-related loads. There is also a seventh 480-V bus designated 3NGY01, dedicated to serve the Condensate Polishing Facility. The system

supplies 480 V, three-phase power to various essential and non-essential electrical loads via switchgear assemblies and distribution network comprised of a number of motor control centers and distribution panels.

Based on an assessment of the peak EDG loads, the 480-V system loading is potentially affected by operation at SPU power levels when the switchgear buses receive their power from the emergency diesel generators due to changes that affect CR fan loading.

When operating at SPU power levels, the EDG loading under steam break LOCA conditions will still be enveloped by the 2000-kW half-hour rating of the EDG, and therefore meets the requirement.

Based on a review of the other loads on the EDG, no other load changes except for the CR fans are anticipated. Therefore, the EDG loading remains adequate for operation under SPU power levels.

Since the worst-case loading on the EDGs when operating under SPU conditions is bounded by the existing EDG load study, and since no other 480-V load changes are identified, the loading on the EDGs is similarly bounded for operating under SPU conditions.

Based on discussions provided in subsection 9.8.1.5.3, the incremental changes in the 480-V system, for example, CR fans, are bounded by the conservatism in the existing load flow analysis.

480-V System Voltage Levels

Review of the existing IP3 load flow analysis and the evaluation model shows that changes in the 6900-V system did not affect the 480-V system at SPU. The estimated effect on 480-V switchgear voltage levels, resulting from unit operation at SPU conditions with 480-V changes, is provided in Tables 9.8-13 and 9.8-14.

The following two scenarios were evaluated:

- Full-Load Normal Operation (Table 9.8-13)

  All five CR fans are running in existing load flow case during normal operation. There are no changes to the 480-V system loads at SPU. The CR fans have no bhp changes at SPU during normal operating conditions. The 480-V bus voltages were taken directly load flow analysis.

- LBLOCA Conditions (Table 9.8-14)

  Four out of five CR fans are running in the existing load flow case during a LBLOCA event (116 kW/fan). In order to estimate the effects of increased bhp for the CR fans, the highest kW per CR fan demand (161.69 kW/fan) was taken from the SPU evaluation on CR fan operation. All four fan motor loads were increased and the 480-V bus loads were estimated for SPU operation. Voltage drops were extrapolated based on the estimated bus loading. The conservatism in the existing load flow analysis bounds the incremental changes in CR fan loading.

Degraded Voltage Relay Settings

Based on Table 9.8-13, bus 6A has the lowest steady-state bus voltage of 441 V at SPU, which is significantly above the existing degraded voltage relay reset setting of 434.8 V. During accident conditions, the greatest estimated change is on bus 5A in Table 9.8-14, which is only 2-V. However, the voltage is estimated to be 457 V, which is also above the degraded voltage relay reset setting. Therefore, the estimated 480-V bus voltages at SPU do not affect the degraded voltage relay settings.

480-V Equipment Fault Duty

Short circuit duty at the 480-V buses is not adversely affected by equipment load changes associated with unit operation at SPU conditions because the load changes did not require replacement of, or changes to, existing electrical components and equipment.

Low-Voltage (440/460-V) Motors, Motor Feeder Cables, Associated Electrical Penetrations, and Overcurrent Protection

Based on Westinghouse assessment of the peak bhp values affected by SPU, CR fan motor power requirements can be conservatively assumed to reach 161.69 kW/fan (corresponding to 195 bhp/fan when four fans out of five are required to operate). The CR fan motors, nameplate rated at 225 HP each, will operate at less than their nameplate rating, and therefore the existing motors are considered adequate to support SPU. Since these are the only low-voltage motors affected by SPU, the remaining low-voltage motors are considered adequate as well.

Since the bhp of the CR fan motors, when operating under SPU conditions, is bounded by the existing rating, it can be concluded that the feeder cable ampacity, electrical penetrations, and overcurrent trip setpoint associated with CR fan motors are adequate to support unit operation at SPU.

9.8.1.8.2.2 13.8-kV System

The 13.8-kV system provides backup electrical power to the 6900-V buses 5 and 6. Unit operation at SPU conditions does not result in a load change to any equipment supplied from 6900-V buses 5 and 6 other than the CR fan loads described above. Additionally, review of the bus loading included in the load flow/voltage profile analysis indicates that loads supplied from the 13.8-kV system during plant shutdown are unaffected by unit operation at SPU conditions.

9.8.1.8.2.3 EDG System

Three independent EDGs supply emergency power to the engineered safeguards features (ESFs) buses in the event of a loss-of-offsite-AC-auxiliary power. Each EDG is started automatically on a SI signal or upon the occurrence of an under-voltage signal on any safeguards 480-V switchgear bus. Any two diesels have adequate capacity to supply the ESFs loads for the hypothetical design bases accident concurrent with loss-of-offsite power (LOOP). This capacity is adequate to provide a safe and orderly plant shutdown in case of loss-of-offsite-electrical power. The EDG system includes the bus duct connections up to the 480-V switchgear circuit breaker generator-side stabs. The 480-V switchgear buses and associated circuit breakers are included in the 480-V power distribution system.

EDG System Loading

The EDGs ratings are as follows:

• Continuous operation	1750 kW
• 2000-hour operation	1950 kW (peak)
• 2-hour operation	1950 kW
• 30-minute operation	2000 kW

Based on assessment of the peak EDG loads, the 480-V system loading is potentially affected by operation at SPU power levels when the switchgear buses receive their power from the EDGs. Currently, this load is 157.3 kW/fan (maximum load occurring when three out of five CR fans are operating. In accordance with the SPU analysis, the maximum BHP requirements for the equivalent scenario (when three out of five CR fans are operating) under SPU conditions is 154.51 kW/fan (maximum load occurring during a LBLOCA with EDG31 failure.) This represents a decrease in the required kW per fan of approximately 2.8 kW. Since EDG32 supplies only one CR fan, the resulting peak EDG32 load decreases from 1984.8 to 1981.6 kW. This represents an improvement in the existing EDG peak loading for the postulated accident case, when operating under SPU conditions.

Since the loading on the EDGs resulting from SPU is bounded by the existing EDG load study, the loading on the EDG bus ducts is similarly bounded.

9.8.1.8.2.4 118-VAC Instrument Supply System

The 118-VAC instrument power distribution system consists of four bus pairs, 31and 31A, 32 and 32A, 33 and 32A, and 34 and 34A. The 118-VAC power is provided to safeguards and non-safeguards plant instrumentation and controls. Instrument bus power is provided by static inverters, which are in turn supplied from separate 125-VDC buses. Backup power is available from voltage-regulated transformers fed from motor-control centers (MCCs).

Existing 118-VAC power and control schemes supplied from the system are unaffected by SPU. Similarly, no new equipment requiring 118-VAC motive or control power is expected to be added to support SPU. Consequently, the 118-VAC system will not be affected by operation at SPU conditions.

9.8.1.8.2.5 125-VDC System

The 125-VDC power distribution system consists of the following major components that support the 125-VDC safeguards and non-safeguards loads throughout the station:

- (5) Station batteries
- (6) Battery chargers
- (5) Power panels
- (6) Distribution panels

One battery charger is available to each battery so that all batteries are maintained at full charge prior to a postulated loss-of-AC-power incident. The sixth battery charger is an installed spare that could replace any of the safeguards battery charger loads. Battery chargers are fed from respective MCCs and power a distribution panel.

Existing 125-VDC power and control schemes are unaffected by SPU. Similarly, no new equipment requiring 125-VDC motive or control power is expected to be added to support operation under SPU conditions.

Consequently, operation at SPU conditions will not result in load or equipment changes in the 125-VDC system.

9.8.1.8.3 Acceptance Criteria

The objective of this section is to demonstrate that the systems included herein are adequately designed to operate at the SPU power levels. The systems fall into one of two categories:

- Systems that are not affected by any parameter changes associated with SPU or are bounded by existing analysis and are therefore adequate for SPU operation.
- Systems that have small or reduced operating parameter changes and can be easily demonstrated as adequate.

9.8.1.8.4 Evaluation

The 480-V system, 13.8-kV system, EDGs, 118-VAC system, and 125-VDC system are described in the IP3 UFSAR (Reference 1) Sections 8.2.2, 8.2.3, and shown in Figure 8.2-9. The proposed SPU affects the operating BHP of the safety-related CR fan motors. All motors will operate within their nameplate ratings at SPU. EDG loading, including changes due to the CR fans, is bounded within the existing IP3 analysis. The EDGs will operate within their 30-minute rating (2000 kW) during peak accident loading conditions. The changes due to this SPU do not reduce the capacity and capability of any system to perform its intended function during anticipated operational occurrences and accident conditions. The 480-V system has been analyzed to approximate the maximum incremental change in operating voltage due to safety and non-safety-related motor bhp changes. The changes proposed by this SPU marginally affect the 480-V system operating voltages and do not affect the existing degraded voltage relay settings. There are no changes to the 125-VDC or 118-VAC systems as a result of the SPU. There are no changes to the control circuits, power circuits, or auxiliary support systems and features that support safety-related loads. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

The Emergency Diesel Engine Fuel Oil and Transfer System is not affected by the SPU. The subject area of Emergency Diesel Engine Fuel Oil and Transfer System effect due to the SPU has a bearing on reactor safety because the emergency diesel engine must be able to support the EDG operation throughout its design mission. The evaluation concludes that the loading on the EDGs resulting from SPU remains within the existing EDG load study. The demands on the Emergency Diesel Engine Fuel Oil and Transfer System are based on fuel consumption for the existing load study. Therefore, the Emergency Diesel Engine Fuel Oil and Transfer System will provide sufficient fuel to support diesel requirements at SPU conditions.

9.8.1.8.5 Results and Conclusions

Results are identified within the evaluation discussion for the applicable system.

The system evaluations included in this section concluded that the following systems are not affected by power SPU or are bounded by existing analysis and are considered adequate as installed for operation at SPU conditions:

- 480-V system
- 13.8-kV system
- EDG system
- 118-VAC instrument supply system
- 125-VDC system

The system evaluation included in this section concluded that the 480-V system voltage levels are not affected by power SPU. The evaluation concludes that the SPU will have a marginal effect on 480-V system voltage levels for normal operation and steam break LOCA conditions based on load flow analysis (Tables 9.8-13 and 9.8-14). The evaluation also concluded that all other aspects of the 480-V system are not affected by power SPU or are bounded by existing analyses and are considered adequate as installed for operation at SPU conditions.

9.8.1.9 Grid Stability

9.8.1.9.1 Input Parameters and Assumptions

Grid stability was reviewed to assess the transmission system impact resulting from power SPU at IP3. The purpose of the review was to verify that the transmission system would remain stable under SPU conditions, and to determine stability issues or modifications, if any, that require resolution to support power SPU. The evaluation included herein was based upon system studies performed by PowerGEM (Reference 3).

The studies were conducted to assess the system reliability impact of a power SPU by Entergy of the Indian Point 2 (IP2) and IP3 nuclear power plants. The studies followed the New York Independent System Operator (NYISO) System Reliability Impact Study (SRIS) Criteria and Procedures. The studies evaluated two independent SPU programs—the IP2 SPU from 1042 MW (gross) to 1078 MW and IP3 SPU from 1042 to 1080 MW. (Both units had previously been evaluated to a conservatively high value of 1042 MW.)

The review was based upon the inputs and assumptions identified below.

Interconnection Plan

No changes to the connection of IP2 and IP3 to the bulk power system, or the impedances of the generators of generator step-up transformers, are planned as part of the SPUs.

The study period was summer 2005 and winter 2005/2006. Plant gross MW outputs, which are maximum winter values, were assumed to be the same for both seasons.

The bulk power system of North America's entire eastern interconnection was represented in the study. The study focused on the area of the bulk system in proximity to, and most likely to be affected by the SPUs. This included the area of New York State from Utica, east to and including the New York-New England (NY-NE) interconnections, and from Utica, south to New York City (NYC), including the New York-Pennsylvania-Jersey-Maryland (PJM) interconnections.

9.8.1.9.2 Description of Analysis

The following analyses were conducted:

- Evaluation of impact on transfer limits and transfer capability

  Analyses determined the incremental impact of the SPUs on the normal and emergency transfer limits of transmission interfaces within the study area considering thermal, voltage and stability limitations. The interfaces considered were: Central-East, Total-East, Upper New York-Southeast New York (UPNY-SENY), UPNY-Con Edison, NYC Cable Interface, NYISO-PJM, PJM-NYISO, NYISO-Independent System Operator New England (ISONE), and ISONE-NYISO. Summer and winter peak load conditions were analyzed.

- Thermal Analysis

  Thermal analyses were conducted to evaluate the impact of the SPUs on the thermal transfer limits of the above interfaces, and on the Con Edison Bulk Power Transmission System in the Buchanan area, in accordance with the Con Edison design criteria. The effect of the SPUs on the phase-shifted regulating lines controlling the 1000-MW wheeling contract between Public Service Enterprise Group (PSE&G) and Con Edison were also evaluated.

- Voltage Analysis

  Voltage analyses were conducted to evaluate the impact of the SPUs on the New York bulk power system transmission system, the Con Edison system (emphasis on the Buchanan area), in accordance with NYISO Transmission Planning Guideline No. 2.

- Stability Analysis

  Stability analyses were conducted to assess the stability impact of the SPUs on the bulk transmission system in accordance with NYISO Transmission Planning Guideline No. 3. The stability analyses evaluated the transient stability performance of the system for normal criteria contingencies in accordance with Northeast Power Coordinating Council (NPCC), NYSRC, and NYISO criteria and standards. In addition, the impact of the SPUs on critical clearing times of Con Edison's substations in the area was determined.

- Extreme Contingence Assessment

  Evaluations were performed on significant load flow studies and significant stability studies for pre- and post-SPU system performance for the most severe contingencies as specified in Section 7.0 of NPCC's Basic Criteria, titled "Extreme Contingency Assessment."

- Short Circuit Analysis

  No changes to IP2 or IP3 generator impedances, generator step-up transformer impedances, or interconnections to the bulk power system are anticipated. Thus, there would be no effect of the SPUs on short circuit contributions when calculated in accordance with the NYISO guideline for fault current assessment.

9.8.1.9.3 Acceptance Criteria

Operation under SPU conditions will not adversely affect transmission system stability or existing power system performance.

9.8.1.9.4 Evaluation

The 345 kV offsite power systems discussed in this report are described in the IP3 UFSAR (Reference 1) Sections 8.1.1 and 8.2.1. No changes to the offsite power system are required as a result of the proposed IP3 SPU. Thermal analysis shows no adverse impact on the transmission interfaces to IP3 during increased plant output at SPU. Contingency analysis

shows almost no change in voltage behavior at SPU based on the loss of several major transmission circuits or a large generator. Stability analysis shows that the grid remains stable after clearing various postulated faults. This stability analysis shows that the loss of the largest operating unit on the grid will not result in loss of grid stability and availability of offsite power to IP3. Since the IP3 SPU has almost no effect on the power grid, no voltage changes from the grid are seen on the IP3 distribution system that would result in changes to degraded voltage relays. Because the grid remains stable for the conditions analyzed, the 138 kV system will remain available for offsite power feed. The onsite electrical distribution system independence, redundancy, and testability to perform safety functions has not been affected by the grid system stability. The onsite and offsite power systems will continue to meet the requirements of GDC-17 (Reference 2) following implementation of the proposed SPU.

9.8.1.9.5 Results and Conclusions

The results of the analyses described above demonstrated that all applicable NYISO criteria are satisfied, and that no modifications are required for IP3 as a result of the SPUs.

The grid system stability is acceptable, and there are no modifications required as a result of IP3 SPU operation.

9.8.2 References

1. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report*, Docket No. 50-286.

2. 10CFR50, Appendix A, General Design Criteria for Nuclear Power Plants, Criterion 17

3. System Reliability Impact Study: Extended Power Uprate of IP2 and IP3, Power GEM Study, February 24, 2004

Table 9.8-1 IP3 IPB Duct Loading Generator Lagging Power Factor, (Exporting MVARs) House Loads from UAT[1,2,3]							
MVA	MWe	MVAR	Gen. Voltage (p.u.)	32 kA Bus Load (A)	16 kA Bus to MT31 Load (A)	16 kA Bus to MT32 UAT Load (A)	1.5 kA Tap Bus Load (kA)
1125.6	1093.5	267	0.95	31,095	14,919	16,183	1331
1103	1080	225	0.95	30,475	14,618	15,866	1328

Notes:

1. MVA, MVAR based on review of generator capability curve at SPU.
2. UAT load for normal plant operation from Table 9.8-3.
3. Loads shown in table are based on the evaluation model.

Table 9.8-2 IP3 IPB Duct Loading Generator Leading Power Factor, (Importing MVARs) House Loads from UAT[1,2,3]							
MVA	MWe	MVAR	Gen. Voltage (p.u.)	32 kA Bus Load (A)	16 kA Bus to MT31 Load (A)	16 kA Bus to MT32 UAT Load (A)	1.5 kA Tap Bus Load (kA)
1101	1093.5	-124	0.95	30,400	14,693	15,726	1328
1085	1080	-100	0.95	29,962	14,464	15,516	1327

Notes:

1. MVA, MVAR based on review of generator capability curve at SPU.
2. UAT load for normal plant operation from Table 9.8-3.
3. Loads shown in table are based on the evaluation model.

Table 9.8-3 UAT Load, Primary Winding - Normal Full-load Conditions			
	Primary Winding		
	MW	MVAR	MVA(1)
Existing Load(2)	40.191	26.239	47.998
Load Increase for SPU	0.048	0.041	
Total Load at SPU	40.239	26.280	48.061

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing UAT primary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase for SPU = Total Load at SPU - Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.

Table 9.8-4 MT Output Loading (Approx. 48 MVA UAT Load)							
Main Generator Output(1)				MT Output Load(2)			Max Rated Output Using Both Transformers(3)
MW	MVAR	MVA(4)	PF, %(5)	MW31 Loading MVA(6)	MT32 Loading MVA(6)	Total Plant Output MVA(6,7)	MVA
Unit Operating at Lagging Power Factor (exporting VARs)							
1093.5	267	1125.6	97.1	526.389	526.741	1053.104	1214
Unit Operating at Leading Power Factor (importing VARs)							
1093.5	-124	1101	99.3	548.596	548.990	1097.560	1214

Notes:

1. Main generator output based on discussion given in section 9.8.1.1.1.
2. When house load is supplied via UAT, MT Output Load = Main Generator Output – (UAT load + Main Transformer Losses). When the house load is supplied via the SAT, MT Output Load = Main Generator Output – Main Transformer Losses.
3. MT rated output taken from MT at 65°C rise.
4. MVA = $(MW2 + MVAR2)^{1/2}$.
5. Power Factor (PF), % = $\frac{MW}{MVA} x100$
6. Loads shown in table are from evaluation model load flow results.
7. MT31 and MT32 have different X/R ratios. Therefore, total plant output MVA is taken directly from load flow analysis using the swing bus power absorption.

Table 9.8-5 Main Transformer Output Loading (no UAT load)							
Main Generator Output[1]				MT Output Load[2]			Max Rated Output Using Both Transformers[3]
MW	MVAR	MVA[4]	PF, %[5]	MW31 Loading MVA[6]	MT32 Loading MVA[6]	Total Plant Output MVA[6,7]	MVA
Unit Operating at Lagging Power Factor (exporting VARs)							
1093.5	267	1125.6	97.1	546.674	547.180	1093.828	1214
Unit Operating at Leading Power Factor (importing VARs)							
1093.5	-124	1101	99.3	565.640	566.164	1131.776	1214

Notes:

1. Main generator output based on discussion given in section 9.8.1.1.1.
2. When house load is supplied via UAT, MT Output Load = Main Generator Output – (UAT load + Main Transformer Losses). Otherwise, MT Output Load = Main Generator Output – Main Transformer Losses.
3. MT rated output taken from MT nameplate at 65°C rise.
4. $MVA = (MW2 + MVAR2)^{1/2}$.
5. Power Factor (PF), % = $\frac{MW}{MVA} x100$
6. Loads shown in table are from evaluation model load flow results.
7. MT31 and MT32 have different X/R ratios. Therefore, total plant output MVA is taken directly from load flow analysis using the swing bus power absorption.

Table 9.8-6 UAT Load, Secondary Winding – Maximum Full-Load Conditions				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA(1)	
Existing Load(2)	39.873	19.782	44.510	43.00 / 48.16
Load Increase for SPU	0.048	0.022	0.053	
Total at SPU	39.921	19.804	44.563	43.00 / 48.16

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing UAT secondary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase for SPU = Total at SPU – Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.

Table 9.8-7 SAT Output Loading Supplying Buses 5 and 6 during Normal Unit Operating Conditions				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA(1)	
Existing Load(2)	7.483	4.216	8.589	43.00 / 48.16
Load Increase at SPU(3)	-0.001	0.000	-0.001	
Total at SPU(4)	7.482	4.216	8.588	43.00 / 48.16

Table 9.8-8 SAT Output Loading Supplying Buses 1, 2, 3, 4, 5 and 6 during Steam Break Accident Condition				
	Output Loading			Maximum Nameplate Rating MVA @55/65°C
	MW	MVAR	MVA(1,5)	
Existing Load(2)	43.970	22.316	49.309	43.00 / 48.16
Load Increase at SPU(3)	-0.016	0.000	-0.016	
Total at SPU(4)	43.954	22.316	49.295	43.00 / 48.16

Notes:

1. $MVA = (MW^2 + MVAR^2)^{1/2}$
2. Existing SAT secondary loading taken from IP3 load flow analysis and used as a baseline for the evaluation model.
3. Load Increase at SPU = Total at SPU – Existing Load. This includes the effects of revised bhp values, transformer and cable losses, and voltage effects on constant impedance loads.
4. Total at SPU results are taken directly from the evaluation model and include equipment losses from transformers and cables. The bhp changes at SPU conditions have been included.
5. Removing the conservatism from the existing load flow model brings the output loading within the maximum nameplate rating.

Table 9.8-9

6900-V Bus Loading
(maximum loading conditions)

Bus	Bus Loading(1)				Bus Voltage KV(3)	Bus Amps(4)	Breaker Rating Amps(5)
	Loading	MW	MVAR	MVA(2)			
1	Existing	10.70	5.36	11.97	6.769	1021	
	Incremental	-0.07	-0.04	-0.08	-1	-7	1200
	Total	10.63	5.32	11.89	6.768	1014	
2	Existing	10.16	5.19	11.41	6.769	973	
	Incremental	0.05	0.02	0.05	-1	5	1200
	Total	10.21	5.21	11.46	6.768	978	
3	Existing	10.67	5.06	11.81	6.770	1007	
	Incremental	-0.07	-0.04	-0.08	-1	-7	1200
	Total	10.60	5.02	11.73	6.769	1000	
4	Existing	8.33	4.14	9.30	6.770	793	
	Incremental	0.14	0.08	0.16	-1	14	1200
	Total	8.47	4.22	9.46	6.769	807	
5	Existing	23.34	11.86	26.18	7.202	2099	
	Incremental	0.03	0.01	0.03	0	3	2000
	Total(6)	23.37	11.87	26.21	7.202	2102	
6	Existing	20.63	10.41	23.11	7.202	1854	
	Incremental	-0.05	-0.02	-0.05	0	-4	2000
	Total(7)	20.58	10.39	23.05	7.202	1850	
7	Existing	2.391	0.972	2.581	6.841	218	
	Incremental	0.080	0.038	0.089	-1	7	2000
	Total(8)	2.471	1.010	2.669	6.840	225	

Notes:

1. Existing bus-loads, incremental loads, and total load at SPU determined from IP3 load flow analysis.
2. $MVA = (MW^2 + MVAR^2)^{1/2}$
3. Bus voltages are taken directly from load flow results, unless noted otherwise.
4. Non-segregated bus currents are taken directly from load flow results, unless noted otherwise.
5. The 6900 V incoming supply breaker ratings are taken from one-line diagrams.
6. Loading shown for bus 5 includes loads from buses 1 and 2.
7. Loading shown for bus 6 includes loads from buses 3 and 4.
8. For bus 3NBY01, the total load is calculated directly from the incremental load. Voltage and current results are extrapolated based on the incremental load.

Table 9.8-10 6900-V Motor Feeder Breaker Loading at SPU Conditions		
Description	**Motor Load, Amps(1)**	**Breaker Rating, Amps(2)**
Reactor Coolant Pumps		
RCP31, 32, 33, 34	502/634	1200
Condensate Pumps		
CP31, 32, 33	220	1200
Heater Drain Pumps		
HD31, 32	78	1200
Condensate Booster Pump		
CBP31, 32, 33	58	1200

Notes:

1. Motor load amps taken from Table 9.8-11 of this report.
2. Feeder breaker ratings taken from IP3 single-line diagrams.

Table 9.8-11

Motor Load Current and Feeder Cable Ampacity at Uprate Conditions

Affected Pump Motor Load	Rated HP(1)	SPU Load BHP(2)	Power Factor(1)	Load Flow(3)		Load Current at SPU, Amps(4)	Cable Ampacity(5)
				MW	MVAR		
Condensate Pump CP31 CP32 CP33	3000	2610	0.90	2.041	0.988	220	315
Cond Booster Pump CBP31 CBP32 CBP33	700	680	0.90	0.540	0.261	58	315 (Note 6)
Heater Drain Pump HD31 HD32	1000	910	0.90	0.718	0.348	78	315
Reactor Coolant Pump RCP31 RCP32 RCP33 RCP34	6000	5969 (Hot)	0.90	4.722	2.288	510	630
Reactor Coolant Pump RCP31 RCP32 RCP33 RCP34	6000	7425 (Cold)	0.90	5.874	2.846	634 (Note 7)	630

Notes:

1. The rated HP for each motor was taken from the IP3 motor data calculation. The cold loop rating for the RCPs was taken from the EMD Curtis-Wright RCP motor evaluation.
2. SPU load bhp for BOP motors (condensate pumps, condensate booster pumps, and heater drain pumps) were based on analysis at 3244 MWt (3216 MWt with 0.5% margin).
3. Load flow MW and MVAR are taken from load flow analysis at SPU. MW and MVAR for RCPs at cold loop calculated by direct proportion between cold loop and hot loop BHP.
4. Motor full-load current (amps) calculated at 90% rated voltage, as follows:

$$\frac{\sqrt{MW^2 + MVAR^2}}{\sqrt{3} \times 6.6kV \times 0.9} \times 1000$$

5. Minimum feeder cable ampacity based on time-current coordination plots given in IP3 short-circuit calculations.
6. Condensate booster pump cable ampacity could not be confirmed. It is assumed that the cable is a 250kcmil with an ampacity similar to other cables of the same size and voltage rating.
7. Although the cold loop current drawn by the RCP marginally exceeds the cable ampacity at 90% of rated voltage, motor current would be 627 A at 91% of rated voltage. Also, the RCP cold loop current is not continuous and its hot loop current is less than the cable continuous ampacity.

Table 9.8-12 6600-V Motors Affected by SPU Conditions		
Affected Pump Motor Load	Nameplate Rating (HP)(1)	SPU Load (BHP)(2,3)
Condensate Pumps		
CP31	3000	2610
CP32	3000	2610
CP33	3000	2610
Cond. Booster Pump		
CBP31	700	680
CBP32	700	680
CBP33	700	680
Heater Drain Pump		
HD31	1000	910
HD32	1000	910
Reactor Coolant Pumps		
RCP31	6000 7500	5969 (Hot) 7425 (Cold)
RCP32	6000 7500	5969 (Hot) 7425 (Cold)
RCP33	6000 7500	5969 (Hot) 7425 (Cold)
RCP34	6000 7500	5969 (Hot) 7425 (Cold)

Notes:

1. The rated HP for each motor was taken from the IP3 motor data calculation. The cold loop rating for the RCPs was taken from the RCP motor evaluation.
2. SPU Load bhps for BOP motors (condensate pumps, condensate booster pumps, and heater drain pumps) were based on analysis at 3244 MWt (3216 MWt with 0.5% margin).
3. RCP BHP for hot- and cold-loop operation taken from the RCP motor evaluation.

Table 9.8-13 Estimated Voltage at 480-V Switchgear Buses (full-load normal operation)				
	Voltage (V)			
			Delta	
Equipment	Existing(1)	SPU(2)	(V)	(%)
Bus 2A	447	447	0	0
Bus 3A	450	450	0	0
Bus 5A	442	442	0	0
Bus 6A	441	441	0	0
Bus 312	442	442	0	0
Bus 313	453	453	0	0

Note:

1. Existing bus voltages taken from IP3 load flow analysis and used as a baseline for the evaluation model.
2. Bus voltages at SPU taken from the evaluation model. These voltages do not represent actual bus voltages, but only signify the expected voltage change due to SPU.

Table 9.8-14 Estimated Voltage at 480-V Switchgear Buses (LBLOCA condition)				
	Voltage (V)			
			Delta	
Equipment	Existing(1)	SPU(2)	(V)	(%)
Bus 2A	475	474	1	0.2
Bus 3A	480	479	1	0.2
Bus 5A	459	457	2	0.4
Bus 6A	475	475	0	0.0
Bus 312	473	473	0	0.0
Bus 313	483	483	0	0.0

Note:

1. Existing bus voltages taken from IP3 load flow analysis and used as a baseline for the evaluation model.
2. Bus voltages at SPU taken from the evaluation model. These voltages do not represent actual bus voltages, but only signify the expected voltage change due to SPU.

9.9 Piping and Supports

9.9.1 Introduction

The purpose of the piping review is to evaluate piping systems for the effects resulting from stretch power uprate (SPU) conditions to demonstrate design basis compliance in accordance with USAS B31.1-1967, Code for Pressure Piping (Reference 1).

The scope of the Indian Point Unit 3 (IP3) piping that was evaluated for SPU conditions included the following piping systems.

Steam and Power Conversion Systems

- Main steam (MS)
- Extraction steam
- Condensate
- Feedwater
- Heater drains
- Moisture separator, moisture pre-separator (MOP), and reheater drains
- Steam generator blowdown
- Circulating water

Auxiliary Systems

- Auxiliary feedwater (AFW)
- Fuel pit cooling
- Service water (SW)

Miscellaneous Balance-of-Plant (BOP) Systems

- Auxiliary steam

9.9.2 Description of Analysis and Evaluation

System operation at SPU conditions generally results in increased pipe stress levels and pipe support loads due to slightly higher operating temperatures, pressures, and flow rates internal to the piping.

The piping systems affected by SPU were evaluated to the current code of record for IP3 as follows.

Pre-uprate and SPU operating data (operating temperature, pressure, and flow rate) were obtained from heat balance diagrams, calculations, and/or other applicable reference documents.

Change factors were determined, as required, to evaluate and compare the changes in operating conditions. The thermal, pressure, and flow rate change factors were based on the following ratios:

- The thermal change factor was based on the ratio of the SPU to pre-uprate operating temperature. That is, thermal change factor is $(T_{uprate}-70°F)/(T_{pre\text{-}}uprate-70°F)$.
- The pressure change factor was determined by the ratio of $(P_{uprate}/P_{pre\text{-}uprate})$.
- The flow rate change factor was determined by the ratio of $(Flow_{uprate}/Flow_{pre\text{-}uprate})$.

These thermal, pressure, and flow rate change factors were used in determining the acceptability of piping systems for SPU conditions.

For thermal, pressure, and flow rate change factors less than or equal to 1.0 (that is, the pre-uprate condition envelops or equals the SPU condition), the piping system was concluded to be acceptable for SPU conditions.

For thermal, pressure, and flow rate change factors greater than 1.0, additional evaluations or detailed analyses were performed to address the specific increase in temperature, pressure, and/or flow rate to document design basis compliance.

Applicable rupture postulation criteria and related design basis documents for IP3 were reviewed and changes to piping system stress levels resulting from the SPU were reconciled against these design basis documents. The evaluations performed concluded that the SPU does not result in any new or revised break locations, and the existing design basis for pipe break, jet impingement, and pipe whip considerations remains valid for the SPU.

All impacted piping and supports were evaluated for changes in operating temperatures, pressures, and flow rates resulting from SPU. The results of these evaluations showed that all piping and supports continue to satisfy existing design basis requirements. Piping systems experiencing higher flow rates will be reviewed for flow-induced vibration (FIV) issues as part of the start-up testing program related to the overall implementation of the SPU.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from the SPU. The existing seismic design basis for all equipment qualification (EQ) remains valid and unaffected by the SPU.

The evaluations reconciling SPU conditions have addressed applicable piping systems for potential increases in steam-hammer or water-hammer loads. The MS piping was evaluated to reconcile the increased loads resulting from a turbine-stop-valve-closure event. The evaluations performed concluded that the MS piping system can withstand the steam-hammer loads associated with SPU conditions.

The results of the piping system evaluations indicate that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions.

For those piping systems that required detailed analyses for change factors greater than 1.0, a summary of revised stress levels corresponding to SPU conditions is provided in Table 9.9-1. The results presented include existing stress levels (that is, pre-uprate), revised pipe stress levels for SPU conditions, allowable stress for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile SPU conditions. The design margin provided is based on the ratio of the calculated stress divided by the allowable stress.

Plant Walkdown Summary

To further support the evaluations that were performed on the condensate, feedwater, extraction steam, feedwater heaters vents and drains, and moisture separator and reheater drains systems, a plant walkdown of these power cycle systems was performed to review the piping layouts and support configurations. The purpose of the piping system walkdowns was to assess the adequacy of the installed piping deadweight spans and to review the existing thermal flexibility of the piping systems.

The portion of these piping systems located in the Turbine Building was the focus of the walkdowns performed. The overall assessment from the walkdowns performed concluded that the existing piping that was observed was adequately supported and that it contained adequate flexibility to accommodate the small temperature and pressure changes resulting from SPU. Piping systems were determined to be adequately supported if the piping was supported by vertical supports, rod hangers, or spring hangers, so that piping spans were consistent with the guidance presented in USAS B31.1-1967, Code for Pressure Piping (Reference 1). Piping systems were determined to have adequate flexibility if the following attributes were observed:

- Piping lengths and offsets were consistent with simplified industry methods of determining flexibility (for example, nomographs).

- There were no non-integral or integrally welded piping anchors installed.
- There was a sufficient and reasonable number of piping elbows installed providing thermal flexibility.

9.9.3 Acceptance Criteria

The piping evaluations were performed to demonstrate design basis compliance in accordance with the USAS B31.1–1967, Code for Pressure Piping (Reference 1).

For those piping systems that required detailed analyses, Table 9.9-1 provides a summary of the allowable stress for the applicable loading condition that required evaluation, along with the existing (pre-uprate) stress and revised stress corresponding to SPU conditions.

9.9.4 Results and Conclusions

The piping and pipe support evaluations performed showed that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure, and flow rate effects resulting from SPU conditions. The piping evaluations also concluded that the Main Steam System (MSS) can withstand the steam-hammer loads associated with SPU conditions. The piping and support systems will continue to meet their licensing basis and satisfy the requirements of General Design Criterias (GDCs)-1, 2, 4, 14, and 15.

The evaluations also demonstrated that the SPU does not result in any new or revised break locations, and the design basis for pipe break, jet impingement, and pipe whip considerations remain valid for the SPU. Hence, for rupture postulation issues, the piping, and support systems continue to meet their licensing basis and satisfy the requirements of GDC- 4.

There were no changes to any seismic inputs (amplified response spectra) or loads resulting from SPU. The existing seismic design basis for all equipment qualification remains valid and unaffected by the SPU. Therefore, the existing licensing basis for the seismic qualification of equipment remains valid and satisfies the requirements of GDCs-1, 2, 4, 14, and 30.

Lastly, an important element of successful operation of IP3 at SPU conditions is the monitoring and evaluation of piping vibration. Lessons learned from power uprates indicate that increased vibration of components in systems experiencing increased flow rates under uprated conditions has caused fatigue-induced failures, and that these conditions may not be readily identified during the analysis phase of the SPU Program. Accordingly, in support of the SPU, piping vibration will be monitored during the power ascension to the SPU power level.

9.9.5 References

1. *USA Standard Code for Pressure Piping, Power Piping USAS B31.1,* 1967 Edition, The American Society of Mechanical Engineers, New York, NY.

Table 9.9-1 Stress Summary at SPU Conditions					
Piping Analysis Description	**Loading Condition(1)**	**Existing Stress (psi)**	**SPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Ratio(2)**
Main Steamline 1 (inside containment)	DL + LP + TSV	12,410	12,587	21,000	0.60
Main Steamline 2 (inside containment)	DL + LP + TSV	11,833	11,993	21,000	0.57
Main Steamline 3 (inside containment)	DL + LP + TSV	12,812	13,234	21,000	0.63
Main Steamline 4 (inside containment)	DL + LP + TSV	12,649	12,811	21,000	0.61
Main Steamlines 1, 2, 3 and 4 (outside containment)	DL + LP + TSV	18,489	19,171	19,950	0.96
Extraction Steamlines to Inlet of Feedwater Heaters 36A/B/C	Thermal expansion	14,189	14,331	22,500	0.64

Notes:

1. Loading condition "DL + LP + TSV" corresponds to the combination of stresses due to deadweight + pressure + turbine stop valve effects.
2. Stress Ratio reported is based on the ratio of SPU stress divided by the allowable stress.

9.10 BOP Instrumentation and Controls

A review was performed on the following balance-of-plant (BOP) systems:

- Steam and power conversion systems
- Auxiliary systems
- Miscellaneous BOP systems
- Electrical systems

As a result of the review, it was concluded that the BOP instrument and controls (I&C) systems equipment will accommodate the Indian Point Unit 3 (IP3) stretch power uprate (SPU) operation

It was also determined that the changes in plant process values resulting from SPU conditions do not require re-scaling of any existing BOP instrumentation.

9.11 Area Ventilation (HVAC)

A review of Indian Point Unit 3 (IP3) area heating, ventilation, and air conditioning (HVAC) systems was performed to determine the impact of the stretch power uprate (SPU) on system operation. Systems reviewed were grouped as follows:

- Primary Auxiliary Building (PAB)/Electrical Penetration Tunnels (EPTs)/Emergency Diesel Generator (EDG) Building HVAC Systems
- Fuel-Storage Building (FSB) HVAC System
- Central Control Room (CCR) HVAC System
- Containment Heating, Ventilation, and Heat Removal HVAC System

9.11.1 Introduction

9.11.1.1 HVAC Systems in the PAB, EPT, and EDG Building

The IP3 HVAC systems in the PAB, EPT, and EDG Building are designed to remove heat generated from operating equipment and piping, and to maintain safe ambient operating temperatures for equipment and personnel. The HVAC systems associated with areas containing radioactive material also control airborne radioactive contamination, ensure air flow is from areas of low contamination to areas of higher contamination, provide for controlled cleanup of contaminated air, and provide for safe release to the environment.

9.11.1.2 HVAC System in the Fuel-Storage Building

The primary function of the HVAC system in the FSB is to provide ventilation air to remove heat and moisture buildup generated from spent fuel decay heat and from operating equipment, and to maintain safe ambient operating temperatures for equipment and personnel. The secondary function of this system is to remove potential airborne radioactive contamination from the area during an accident and provide for controlled cleanup of contaminated air for safe release to the environment. Note that Section 6.11.9 takes no credit for filtration in the FSB.

9.11.1.3 Central Control Room HVAC System

The IP3 CCR HVAC system is designed to provide the following functions:

- Maintain the required design temperature and relative humidity inside the CCR during all modes of plant operation.

- Isolate the CCR to prevent infiltration of toxic gases and smoke, and cleanup of airborne radioactive particulates in the outdoor air entering the CCR during high radiation and/or safety injection (SI) conditions.

- Provide slight positive pressure in the CCR during normal and high radiation or SI modes of operation to prevent in-leakage of airborne contamination from adjoining space.

9.11.1.4 Containment Heating, Ventilation, and Heat Removal System

The Containment Heating, Ventilation, and Heat Removal System is designed to accomplish the following functions:

- Remove normal heat loss from equipment and piping to ensure that a maximum ambient temperature of 130°F is not exceeded.

- Provide positive circulation of air across the refueling water surface to ensure personnel access and safety during shutdown.

- Provide containment heating to maintain a minimum containment temperature of 50°F before the reactor is taken above the cold shutdown condition.

- Purge the containment vessel to the plant vent for dispersion to the environment.

- Depressurize the containment vessel following an accident.

- Provide pressure relief via an exhaust system.

The above functions are accomplished in conjunction with the following subsystems:

- Containment recirculation cooling system
- Control rod drive mechanism (CRDM) cooling system
- Containment purge and pressure relief system

9.11.2 Input Parameters and Assumptions

The primary input assumption associated with evaluating the HVAC systems was that the systems are capable of performing their required functions at the current power level. The systems were evaluated based on input parameters resulting from associated SPU operating conditions as compared with HVAC systems design input parameters.

9.11.3 Description of Analysis and Evaluation

The IP3 HVAC systems were evaluated to determine if the existing system design is capable of performing intended functions under conditions associated with plant SPU to 3216 MWt core power. Expected SPU conditions were compared and evaluated against system design conditions.

The need to perform additional analyses and/or modifications necessary to support SPU was taken into consideration as part of the evaluation.

9.11.4 Acceptance Criteria

The overall acceptance criterion is that the HVAC systems remain capable of performing their design function under IP3 SPU operating conditions. System design parameters must bound SPU operating conditions.

The potential radiological exposure to the operators under post-accident conditions is addressed by the accident analyses. The loss-of-coolant accident (LOCA) analysis assumes an SPU core power level of 3216 MWt. The current analysis must bound the SPU conditions.

9.11.3.5 Design Criteria

The HVAC systems are designed to remove heat from normal heat loss from equipment and maintain a regulated ambient temperature and humidity for equipment and personnel. In an accident condition, an HVAC system may be responsible for removing smoke, gas, and other toxins that may enter a safety-related area.

Portions of the HVAC systems are safety-related. The HVAC systems (as applicable) were designed to meet the intent of the General Design Criteria (GDC), which were published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the HVAC Systems to meet these requirements. Therefore the HVAC systems continue to meet the criterion requirements.

In addition to NRC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L and III.O of 10CFR50 Appendix R (Reference 1) as applicable. Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the HVAC Systems to meet these requirements. Therefore the HVAC Systems continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the HVAC Systems design to meet 10CFR20 (Reference 2) limits as applicable. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the HVAC Systems will continue to meet the criterion requirements.

Environmental qualification (EQ) of HVAC systems electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and DOR Guidelines as applicable (see LAR Section 11, and ER Section 10). Monitoring of the HVAC systems is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of Regulatory Guide (RG) 1.97 (Reference 4). The HVAC systems are designed with provisions to allow post-accident sampling in accordance with the post-TMI Requirements of NUREG 0578 and 0737 (References 5 and 6). The Technical Specification requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the HVAC systems to meet these requirements. Therefore, the HVAC systems continues to meet the criterion requirements.

The HVAC systems design criteria (as applicable), as it relates to accident analyses and the NSSS/BOP interface, are described in Sections 4 and 5 of this document. Other criterion required to meet SPU conditions are listed in the acceptance criteria above.

9.11.5 Results and Conclusions

9.11.5.1 HVAC Systems in the PAB, EPT, and EDG Building

Operation at SPU conditions will not increase the heat load in the PAB above the bounding analysis level, and will not affect the potential airborne contamination in the building.

Operation under SPU conditions will not affect the heat load in the EPT or operation of equipment in the EPT.

Operation at SPU conditions will not affect the heat load or operation of equipment in the EDG Building.

Based on the results discussed above, the impact of SPU operating conditions on the PAB, EPT and EDG HVAC systems will not adversely affect the operational ability of these systems. The systems will function as designed under SPU conditions without limitation. No plant modifications to the PAB, EPT, and EDG HVAC systems are required to support SPU.

9.11.5.2 HVAC System in the Fuel-Storage Building

Operation at SPU conditions will not increase the heat load in the FSB above the bounding analysis (that is, analysis bounds SPU operating conditions). Fuel decay heat will increase slightly as a result of SPU operation, but the normal spent fuel pit (SFP) temperature will not be affected by this slight increase.

Based on the results the evaluation, the impact of SPU on the FSB HVAC system does not adversely affect the operational ability of the system. The FSB HVAC system will function as designed under SPU conditions without limitation. No plant modifications to the FSB HVAC system is required to support SPU.

9.11.5.3 Central Control Room HVAC System

Based on the results discussed above, the impact of SPU on the CCR HVAC system does not adversely affect the operational ability of the system. The system will function as designed under SPU conditions without limitation. No plant modifications to the CCR HVAC system is required to support SPU. However, modifications are planned for the CCR HVAC system during R13 outage to improve charcoal filter design.

9.11.5.4 Containment Heating, Ventilation, and Heat Removal System

Results of the SPU evaluation in conjunction with subsystems making up the Containment Heating, Ventilation, and Heat Removal System are provided below. Based on these results, the impact of SPU on the Containment Heating, Ventilation, and Heat Removal System does not adversely affect the operational ability of the system and associated subsystems. The system and associated subsystems will function as designed under SPU conditions without limitation. No plant modifications to the CCR HVAC system are required to support SPU.

- Containment Recirculation Cooling System

  The Containment Recirculation Cooling System and associated filtration systems maintain ambient containment temperature at or below 130°F, remove heat from containment following an accident, and clean up post-accident containment atmosphere. During the normal mode operation under SPU conditions, the containment heat load will

increase slightly. However, the fan cooling units (FCUs), in conjunction with station operating procedures, will remain adequate for normal operation to maintain containment temperature below 130°F.

For post-accident conditions, the FCUs cooling capacity performance was evaluated as a part of the accident analysis. The capacity to remove fission products from the containment atmosphere after an accident was also evaluated as part of the accident analysis. Under SPU conditions, the system design remains bounding.

- CRDM Cooling System

  The CRDM Cooling System is designed to maintain the control rod drive operating coils stacks at or below their maximum operating temperature of 200°F. Operation under SPU conditions will not significantly affect heat loads or temperature associated with the CRDM. The CRDM Cooling System will continue to meet system functional requirements under SPU operating conditions.

- Containment Purge and Pressure Relief System

  Operation under SPU conditions will not affect operation of the Containment Purge and Pressure Relief System. The containment purge and make-up capability are not impacted by SPU, and operation under SPU conditions will not affect pressure build up in containment during reactor power operation, or the operation of the Containment Pressure Relief System. The Containment Purge and Pressure Relief System will continue to meet system functional requirements under SPU operating conditions.

9.11.6 References

1. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants,* 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, *Clarification of TMI Action Plan Requirements*, November 1980.

9.12 Auxiliary Feedwater System

9.12.1 Introduction

The Auxiliary Feedwater System (AFWS) is designed to provide emergency cooling for the reactor by supplying water to the steam generators. The Feedwater System (FWS) provides water to the steam generators during power operation while the AFWS is used at low power when the steam is not available to operate the main feedwater system. The AFWS also operates under the following conditions:

- Loss-of-main feedwater
- Rupture of a main steam line
- Loss-of-coolant accident (LOCA)
- Loss-of-AC power (LOAC)
- Steam generator tube rupture (SGTR)
- Anticipated transient without scram (ATWS)
- Alternate safe shutdown
- Station blackout (SBO)

The AFWS also provides feedwater to the steam generators to support the ability to cool the RCS to the point at which the Residual Heat Removal System (RHRS) may be brought online to complete the cooldown process (during normal-operation or post-accident scenarios).

Auxiliary feedwater (AFW) is supplied by the actuation of two motor-driven AFW pumps (MDAFWPs), which are initiated by any of the following signals.

- Low-low water level in any steam generator
- Automatic trip (not manual) of any main feedwater pump turbine
- Any safety injection (SI) signal
- ATWS mitigating system actuation circuitry (AMSAC) signal
- Loss-of-offsite power (LOOP)
- Manual actuation

In addition, one turbine-driven AFW pump (TDAFWP) starts on any of the following actuation signals, although no automatic delivery of water to the steam generators occurs (the TDAFWP is automatically started, but must be manually aligned by the operator to allow delivery of AFW flow to the steam generators).

- Low-low water level in any two steam generators
- LOOP concurrent with unit trip and no safety injection signal
- AMSAC signal

The MDAFWPs are powered by the emergency diesel generators (EDGs). The pumps take suction from the condensate storage tank (CST) for delivery to the steam generators. Each MDAFWP is designed to supply the minimum required flow within 60 seconds of the initiating signal. Although the TDAFWP is automatically actuated, this pump is not available to deliver flow to the steam generators until operator action is taken to align the TDAFWP.

The AFWS consists of two distinct safety-grade subsystems (that is, two pumping systems using different sources of motive power for their pumps) to ensure reliability of the feedwater supply. The plant original design consisted of a subsystem with two trains, each with a 100-percent capacity MDAFWP designed to deliver flow to two of the four steam generators. The second subsystem consisted of a 200-percent capacity TDAFWP designed to deliver flow to all four steam generators.

There are two independent water supplies available to the AFWS. These two sources are configured so that there are two redundant suction flow paths to each AFW pump. One flow path is a single line from the CST; the second flow path is a single line from the city water storage tank. Only one source is aligned to the pumps at one time.

9.12.2 Input Parameters

The required AFWS flow and capacity are proportional to the amount of decay heat that must be removed from the core during accident conditions. The AFWS functions associated with normal plant startup and shutdown are not dependent on core power and, therefore, are not affected by the stretch power uprate (SPU).

The design capacities of AFW pumps as follows:

- MDAFWP: 400 gpm
- TDAFWP: 800 gpm

The AFW pumps are normally aligned to take suction from the CST for delivery to the steam generators. The limiting transient with respect to CST inventory requirements is the LOAC transient. The IP3 licensing basis requires that, in the event of a LOAC, sufficient CST useable inventory must be available to bring the plant from full-power to hot-standby conditions, and maintain the plant at hot standby for 24 hours. Since the duration of the SBO event is less than 24 hours, it is bounded by maintaining hot standby for 24 hours. (see subsection 4.2.4.1). Technical Specification 3.7.6 requires a minimum CST useable inventory of 360,000 gallons. An alarm and interlock at 20 ft (< or = 385,000 gallons) ensures the compliance with Technical Specification 3.7.6. The interlock closes other users' isolation valves to preserve CST volume for AFWS.

The CST operating water temperature is at the maximum allowable value of 120°F.

The design pressure and temperature of AFW pump discharge piping and components are 1440 psig and 450°F. The design pressure and temperature of AFW pump suction piping and components are 150 psig and 225°F.

9.12.3 Description of Analysis and Evaluation

Evaluation of the AFWS consisted of documenting the current system functional requirements for transients/accidents and the extent to which SPU impacts these AFWS functions.

This evaluation compared the design pressure and temperature of piping and components with the SPU maximum operating pressure and temperature (that is, AFWS functions associated with normal plant startup and shutdown).

The evaluation also considered the extent to which sufficient AFW flow is provided to the steam generators following a design basis accident (DBA), and the extent to which adequate water inventory is available in the CST to satisfy AFWS functional requirements (see subsections 4.2.4.1, 6.3.7, 6.3.8, and 6.8 of this document).

9.12.4 Acceptance Criteria

The design pressure and temperature of piping and components bounds the SPU maximum operating pressure and temperature.

Based on the limiting transient with respect to CST inventory requirements (that is, LOAC as described in subsection 4.2.4.1), sufficient 120°F AFW inventory is available to maintain the plant in hot standby for 24 hours following a reactor trip from full power.

The AFWS must provide sufficient flow at the required head to obtain acceptable results for those licensing basis analyses that require AFW flow for transient or accident mitigation.

Licensing-basis acceptance criteria for the AFWS under SPU conditions include the following:

Loss-of-Normal Feedwater (LONF): Provide sufficient AFW cooling to meet the acceptance criteria for LONF (see subsection 6.3.7).

Rupture of a Main Steam Line: Provide isolation of AFW to the faulted-loop steam generator to meet acceptance criteria for the rupture of a steam pipe and for the main steamline break (MSLB) events (see subsections 6.3.11 and 6.6).

LOCA: Provide sufficient AFW to meet the acceptance criteria for LOCA. AFW has only a minor effect on LOCA analyses (see Section 6.2).

LOAC: Provide sufficient AFW cooling to meet the acceptance criteria for LOAC (see subsection 6.3.8).

SGTR: Provide AFW isolation early enough to prevent exceeding offsite dose limits (see Section 6.4 and subsection 6.11.9).

ATWS: Provide sufficient AFW cooling to prevent exceeding a Reactor Coolant System (RCS) pressure service level C limit of 3215 psia (see Section 6.8).

10CFR50, Appendix R (Reference 1) Safe Shutdown/Alternate Safe Shutdown: Provide sufficient AFW cooling to remove decay heat and to cooldown the RCS to RHR entry conditions. This allows the 10CFR50, Appendix R cooldown analysis to demonstrate that the cooldown can be completed within the required 72 hours (see subsections 4.1.3, 4.1.6, and 10.1).

SBO: Provide sufficient condensate inventory to remove decay heat and to cooldown the RCS to minimize RCS inventory loss (see Sections 4.2 and 10.6).

High-Energy Line Break (HELB): Refer to "Rupture of a Main Steam Line" above.

Three Mile Island (TMI) Action Plan Items: TMI Action Plan items for the AFWS, including system reliability analyses, re-evaluation of system design bases, and implementation of requirements for AFW automatic initiation and flowrate indication, continue to be met for the SPU.

9.12.5 Design Criteria

The AFWS is designed to maintain sufficient water inventory in the steam generators to allow removal of decay heat from the RCS by secondary steam releases in the event that the FWS is inoperable. The AFWS is used for plant startup.

The AFWS is nuclear safety-related and required for safe shutdown of the reactor. The AFWS was designed to meet the intent of the General Design Criteria (GDC), which was published by the Atomic Energy Commission (AEC) in the Federal Register of July 11, 1967. The NRC concluded in the *Safety Evaluation Report* (SER), that the plant design conformed to the intent of the newer criteria. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore, the AFWS continues to meet the criteria requirements.

In addition to AEC Criterion 2 (*Performance Standards*), New York Power Authority (NYPA) committed to the requirements of Sections III.G, III.J, III.L and III.O of 10CFR50 Appendix R (Reference 1). Evaluation of IP3 fire protection features against the requirements of Section III.G of Appendix R to 10CFR50 was completed and the report submitted to NRC on August 16, 1984. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore the AFWS continues to meet the criterion requirements.

In addition to AEC Criterion 17 (*Monitoring Radioactive Releases*) and 70 (*Control of Radioactive Releases to the Environment*), provisions are included in the AFWS design to meet 10CFR20 (Reference 2) limits. The radioactive releases at SPU conditions are within the original design basis of the plant. Therefore, the AFWS will continue to meet the criterion requirements.

Environmental qualification (EQ) of AFWS electrical equipment important to safety is demonstrated in EQ packages compiled in accordance with the requirements of 10CFR50.49 (Reference 3) and NRC Guidelines (see Section 10.6). Monitoring of the AFWS is provided as a result of the Three Mile Island 2 (TMI-2) accident investigation and the requirements of NRC Regulatory Guide (RG) 1.97 (Reference 4). The AFWS is designed with provisions to allow post-accident sampling in accordance with the post-TMI requirements of NUREG-0578 (Reference 5) and NUREG-0737 (Reference 6). The *Technical Specification* requirements for sampling provisions were deleted by Amendment 210, dated February 6, 2002. SPU operation does not affect the ability of the AFWS to meet these requirements. Therefore, the AFWS continues to meet the requirements.

Accident analyses acceptance criteria are provided in each subsection in Section 6 for those accidents for which AFW is credited for mitigation. Interface guidelines for the Nuclear Steam Supply Systems (NSSS) and balance-of-plant (BOP) interface are discussed in Section 4.2.

Acceptance criteria required to meet SPU conditions are listed in the subsection 9.12.4.

9.12.6 Results and Conclusions

Since the required CST inventory is a function of plant-rated power and other NSSS design parameters, a new analysis was performed to determine the required inventory for the range of NSSS design parameters approved for the SPU. The analysis concluded that a minimum required useable inventory of 288,500 gallons is required to meet the plant licensing bases for the range of NSSS design parameters approved for the SPU. Thus, considering the unavailable volume and other margins, the design basis requirement remains satisfied by the existing *Technical Specification* CST volume of 360,000 gallons. The volume of water contained in the IP3 CST is adequate to support the SPU (see Sections 4.2 and 10.6).

The AFW pumps can draw from an alternative supply of water to provide for long-term cooling. This alternate supply is from city water storage tank. This alternative supply is manually aligned to the AFW pumps in the event of unavailability of the CST.

The worst single failure modeled in the SPU LONF and LOAC analyses 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 steam generators. Additional flow from a second MDAFWP or the TDAFWP is assumed to be available only following operator action to start a second MDAWFP or align the TDAFWP discharge valves. This operator action is assumed to provide an additional 343 gpm of AFW flow distributed equally to the other two steam generators not receiving AFW automatically, and is assumed to occur at 10 minutes after the reactor trip due to a low-low steam generator water level signal (see subsections 6.3.7 and 6.3.8).

The SPU ATWS analysis assumes normal conditions consistent with the requirements outlined by the NRC. In consideration of the low probability of an ATWS, the NRC permitted normal initial conditions, normal system parameters and the availability of all system functions except reactor trip to be assumed. The SPU ATWS analysis conservatively assumes AFW flow of 343 gpm per pump from two MDAFWPs and no credit for the TDAFWP. The RCS pressure service level C limit of 3215 psia is not exceeded at SPU conditions.

The AFW pumps are capable of providing the required flow and pressure to steam generators during normal plant startup, shutdown, and accident conditions with sufficient net pump suction head (NPSH) available with margin over NPSH required.

The brake horsepower (bhp) requirements of MDAFWPs at the pump flow of 343 gpm and 400 gpm are approximately 440 bhp and 460 bhp, respectively, which are enveloped by horsepower of pump motors designed with a service factor of 1.15 (that is, 400 hp x 1.15 = 460 hp).

AFWS piping and components design pressure and temperature bounds maximum operating pressure and temperature conditions expected under SPU operation. AFWS piping and components are considered acceptable for SPU operation.

The AFWS will provide sufficient flow at the required head to obtain acceptable results for those analyses that require AFW flow for transient or accident mitigation (see subsections 4.1.3, 4.1.6, 6.2, 6.3.7, 6.3.8, 6.8, and 10.1).

AFWS operation under SPU conditions complies with licensing basis acceptance criteria (see subsection 9.12.4).

The AFWS is acceptable for operation under SPU conditions. No system modifications are required.

9.12.7 References

1. 10CFR50, Appendix R, Fire *Protection Program for Nuclear Power Facilities Operating Prior to January 1979,* June 20, 2000.

2. 10CFR20, *Standards for Protection Against Radiation,* May 21, 1991.

3. 10CFR50.49, *Environmental Qualification of Electric Equipment Important To Safety for Nuclear Power Plants*, 66FR64738, December 14, 2001.

4. NRC Regulatory Guide 1.97, *Instrumentation of Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident* (Errata published July 1981) (Draft RS 917-4, Proposed Revision 2, published December 1979) (Rev. 3, ML003740282).

5. NUREG-0578, *TMI Lessons Learned Task Force Status Report and Short Term Recommendations*, July 1979.

6. NUREG-0737, Clarification of TMI Action Plan Requirements, November 1980.

9.13 Structural Analysis

9.13.1 Fuel-Handling Building Structural Analysis

The stretch power uprate (SPU) for Indian Point Unit 3 (IP3) results in fuel with increased radioactivity in the fuel assemblies being transferred from the reactor to the spent fuel pit (SFP) during refueling. The addition of a non-SPU-related effect (the removal of fuel sooner from the reactor after shutdown, that is, 84 hours instead of 100 hours after shutdown), also results in an increased level of radioactivity. The combination of these two conditions may result in the heating of the concrete pit structure by the gamma radiation emanating from the fuel, in the event the fuel is placed in fuel rack cells adjacent to the concrete walls.

The SFP water temperature will be maintained within the limits defined in the system description for the SFP cooling loop. Bounding estimates of the concrete temperature effects can be made with the conservative assumption that as fuel is offloaded it will be immediately placed adjacent to the concrete walls of the pit structure, with no older spent fuel between it and the concrete. The gamma heating is limited to the lower 13 feet of the exterior walls, which are 6-feet, 3-inches thick and in contact with the rock or soil backfill on the outside face, the south wall, which is adjacent to the interior of the Fuel Storage Building, and the 5-foot thick interior fuel transfer canal wall. This 13-foot height comprises the active fuel length (12 feet) and an additional 1 foot to account for the floor of the rack and the lower end of the fuel bundle.

This section describes the analysis made to address the effects of gamma heating on the concrete structure.

9.13.1.1 Input Parameters and Assumptions

The input parameters and the assumptions used in the evaluation of the gamma-heated concrete pit structure are summarized in the following paragraphs.

- The reference temperature, T_{ref}, for the concrete, which is the temperature at which no thermal expansion or contraction occurs, is 70°F.
- The maximum expected SFP water temperature is 120°F during fuel offloading
- The active fuel length in a fuel bundle is 12 feet. This defines the height of the wall above the mat, 13 feet, that is heated by the gamma radiation.

- The non-linear thermal gradient due to gamma heating can be decomposed into a uniform thermal expansion across the section and a linear gradient across the section, producing an equivalent compression and tension and an equivalent bending moment as the nonlinear gradient.

- The volume of the concrete wall affected by gamma heating is approximately equal to the height of the fuel bundle, that is, 13 feet, measured from the SFP floor liner. The thickness of the gamma-heated volume is defined by the gradients calculated for the IP3 SFP. The width of the gamma-heated zone resulting from the radiation from a single fuel bundle is equal to the width of the bundle.

- There is no reduction in the gradient through the wall due to propagation of the heat, away from the gamma-heated volume, obliquely through the wall.

- The temperature of the soil in contact with the SFP mat and lower part of the walls is 50°F.

- The entire SFP is assumed to be exposed to "fresh" fuel, a normal loads condition. The more realistic case, where only specified locations will see fresh fuel, results in local effects that would correspond to an abnormal condition.

9.13.1.2 Description of Analysis and Evaluation

The nonlinear thermal gradient arising from the gamma heating of the concrete structure is converted to a linear gradient producing an equivalent compression and bending moment. The conversion requires the integration of the nonlinear gradient relative to reference temperature, 70°F. This reference temperature is applicable to each face of the concrete walls.

The gamma heating gradients in the concrete walls and mat are developed assuming an SFP water temperature of 120°F at the start of refueling. The equivalent linear gradient for gamma heating is compared to the design basis gradient, a temperature gradient equal to 200°F (the SFP water temperature) less the exterior wall/mat temperature. The comparison is made to demonstrate that the design basis gradients bound the corresponding equivalent linear gradients and that the thermal gradients associated with gamma heating for the SPU refueling condition are, therefore, less limiting.

9.13.1.3 Acceptance Criteria

Equivalent linear gradients derived from the thermal gradients associated with gamma heating for the new SPU refueling condition are bounded by the thermal gradients used in the design basis analysis of the fuel pit.

The peak concrete temperatures determined for the gamma heating condition are less than the maximum value of 200°F used in the design basis analysis for the normal load condition.

9.13.1.4 Design Criteria

American Concrete Institute (ACI) 349-80, "Code Requirements for Nuclear Safety-Related Concrete Structures," provides the design basis criteria by which the thermal stresses in the walls of the SFP resulting from temperature gradients were evaluated.

9.13.1.5 Results and Conclusions

The peak temperature in the 6-foot, 3-inch thick outside walls is 189.2°F.

The peak temperature in the 5-foot thick interior fuel transfer canal wall is 191.4°F.

The analysis has demonstrated that the concrete fuel pit thermal gradients associated with gamma heating for the new SPU refueling condition are less limiting than the corresponding thermal gradients used in the design basis analysis.

The elevated temperatures in the zone of the gamma-heated concrete are acceptable since they are less than the maximum 200°F temperature considered in the design basis analysis.

9.13.2 Auxiliary Boiler Feed Pump Building Structural Analysis

One possible consequence of the SPU is an increase to the outside containment compartment differential pressures due to a high-energy line break (HELB). The compartment differential pressure due to HELB is addressed for the Auxiliary Boiler Feed Pump Building in this section of the report. The Auxiliary Boiler Feed Pump Building includes the "shield wall area" consisting of the steam and feedline penetration area and the auxiliary feed pump room.

A main steam line break (MSLB) or feedline break are the sources of the postulated-accident differential pressure challenging the capacity of the structure, since the smaller breaks do not produce significant differential pressure. Since the postulated break in the auxiliary feed pump

room is the double-ended rupture (DER) of a 4-inch diameter steam line to the auxiliary boiler feed pump turbine, the resulting HELB pressure in this compartment is small.

9.13.2.1 Input Parameters and Assumptions

The input parameters for this evaluation are the HELB differential pressure transients in the outside containment compartments for the SPU. Also, the compartment differential pressures for the current licensed power levels are provided in the plant evaluation of harsh environment areas.

The assumption applicable to this section is that the SPU does not result in changes to the locations of existing, postulated pipe-break locations or to the type of break.

9.13.2.2 Description of Analysis and Evaluation

The outside containment HELB pressure due to SPU conditions were compared to the design pressure capacity or the HELB differential pressure for current licensed thermal power conditions for each of the compartments in the Auxiliary Boiler Feed Pump Building. The structural pressure capacity was reviewed to support the conclusions that the SPU does not govern the compartment design for pressurization. For the steam and feedline penetration area, the sheet metal siding is calculated to commence failure at a differential pressure of 0.46 psig and is completely failed at a pressure of 1.26 psig.

9.13.2.3 Acceptance Criteria

The acceptance criteria for the auxiliary feed pump room are the current licensed thermal power HELB differential pressures for each cubicle or the differential pressure used as the design basis for the structure. Pressures below these values are deemed to meet the acceptance criteria.

Since the enclosure of the steam and feedline penetration area of the Auxiliary Boiler Feed Pump Building is assumed to fail at a differential pressure exceeding 0.46 psig, there are no acceptance criteria for this area. Failure of the sheet metal siding is acceptable.

9.13.2.4 Design Criteria

General Design Criterion (GDC) 4, "Environmental and Dynamic Effects Design Basis," is applicable to the design of the Auxiliary Boiler Feed Pump Building. Criterion 4 of the GDC, listed in 10CFR50, Appendix A, (Reference 1) requires that, "Structures, systems and components important to safety shall be designed to accommodate the effects of and be

compatible with the environmental considerations associated with normal operation, maintenance, testing and postulated accidents, including loss-of-coolant accidents. These structures, systems and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit."

9.13.2.5 Results and Conclusions

The SPU does not result in HELB pressurization exceeding the structural capacity of the affected compartments. Therefore, the structural capacity of the affected compartments is acceptable under SPU conditions.

9.13.3 Miscellaneous Structures

9.13.3.1 Structural Analysis

The SPU does not affect the Primary Auxiliary Building (PAB). Outside containment HELB is the only PAB structural issue affected by the SPU and no changes result from HELB.

9.13.3.2 Turbine Building Structural Analysis

The SPU does not affect the Turbine Building. Outside containment HELB is the only Turbine Building structural issue affected by the SPU and no changes result from HELB.

9.13.4 References

1. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants.*

10.0 GENERIC ISSUES AND PROGRAMS

The Indian Point Unit 3 (IP3) stretch power uprate (SPU) has the potential to affect plant programs and generic issues that have been developed and implemented at IP3 in compliance with various design, maintenance, and licensing requirements. The plant programs and generic issues listed in Table 10-1 were identified for review and evaluation of the effect of the SPU.

For the programs and generic issues listed in Table 10-1, a review of the documentation was performed and discussions with cognizant station personnel were conducted. Based upon review of this information, the effect of the SPU implementation on the program and generic issue was determined.

Table 10-1 identifies if a program/generic issue is either "affected/potentially affected" or "not affected" by the SPU. Programs/generic issues are "not affected" by the SPU if:

- The SPU does not affect key inputs to the program/generic issue, or
- The program/generic issue is based on information/parameters that bound the conditions that will result from implementation of the SPU, or
- Existing program requirements, procedures, or activities will be utilized or applied in support of implementation of the SPU.

Table 10-1 Effect of SPU on IP3 Generic Issues and Programs			
Section	Program/Generic Issue	Not Affected [*]	Affected/ Potentially Affected [*]
10.1	Fire Protection (10CFR50 Appendix R) Program	X	
10.2	Generic Letter 89-10 Motor-Operated Valve (MOV) Program	X	
10.3	Flow-Accelerated Corrosion (FAC) Program		X
10.4	Flooding	X	
10.5	Probabilistic Safety Assessment		X
10.6	Station Blackout	X	
10.7	In-Service Inspection/In-Service Test Programs	X	
10.8	Electrical Equipment Environmental Qualification Program		X
10.9	Chemistry Program	X	
10.10	Generic Letter 95-07	X	
10.11	Generic Letter 96-06	X	
10.12	Generic Letter 89-13	X	
10.13	Plant Simulator		X
10.14	Containment Leak Rate Testing		X
10.15	Plant Operations		X

10.1 Fire Protection (10CFR50 Appendix R) Program

NRC regulatory/guidance documents applicable to the IP3 Fire Protection Program include:

- 10CFR50, Appendix A, General Design Criterion 3 (Reference 1), as addressed in the *Indian Point Unit 3 Updated Final Safety Analysis Report* (UFSAR) Section 1.3.1, "General Design Criteria, Fire Protection (Criterion 3)," (Reference 2).

- 10CFR50, Section 50.48 (Reference 3)

- 10CFR50, Appendix R (Reference 4)

- Branch Technical Position (BTP) 9.5-1 and Appendix A (Reference 5)

- NRC Generic Letters 81-12 (Reference 6), 85-01 (Reference 7), and 86-10 (Reference 8)

The IP3 10CFR50 Appendix *R Safe Shutdown Analysis Report* (referred to herein as the "Shutdown Analysis") describes the safe shutdown model used in the analysis, and evaluates each plant analysis area to determine compliance with 10CFR50 Appendix R Sections III.G and III.L. In accordance with these sections of Appendix R, if shutdown is accomplished using alternate or dedicated systems, cold shutdown must be achieved within 72 hours. To meet Appendix R performance goals, the shutdown analysis states that certain time critical activities have been established, as follows:

- Establish feedwater flow to steam generators
- Establish reactor coolant pump (RCP) seal cooling
- Maintain pressurizer level (re-establish charging)
- Ensure at least one residual heat removel (RHR) pump is available to achieve cold shutdown

Regarding the shutdown analysis time critical activity of establishing feedwater flow to the steam generators, analysis of IP3 steam generator dryout time shows that the required time period for restoring feedwater flow is bounded under SPU conditions.

The time-critical activities of establishing RCP seal cooling and re-establishing charging to maintain pressurizer level are related to loss of RCS inventory due to leakage through the reactor coolant pump (RCP) seals. RCP seal leakage is assumed as per WCAP-10541 Revision 2 (Reference 9) and is not affected by SPU conditions. In addition, the shutdown analysis indicates that numerous charging paths are available for charging to the RCS following an Appendix R fire. Accordingly, it is concluded that the SPU does not affect these activities.

The IP3 Appendix R cooldown analysis under SPU conditions (3216-MWt core power) shows that IP3 is capable of meeting the Appendix R requirement that cold shutdown be achieved within 72 hours after reactor trip following a fire.

For postulated Appendix R fire scenarios concurrent with a loss-of-off-site power (LOOP), the emergency diesel generators (EDGs) are the preferred power supply for safe shutdown equipment. Fire scenarios that cannot credit the EDGs due to fire-induced failures will utilize the Appendix R Diesel Generator and the associated 6.9-kV switchgear. The Appendix R Diesel Generator load analysis determines the capability of the Appendix R Diesel Generator to provide power requirements during hot shutdown and cold shutdown conditions. Evaluation of Appendix R Diesel Generator load requirements under station blackout (SBO) conditions shows that there are no significant load increases that would affect the conclusions of the existing Appendix R Diesel Generator load analysis.

10.1.1 References

1. 10CFR50, Appendix A, *General Design Criteria for Nuclear Power Plants General Design Criterion 3, Fire Protection*, July 11, 1967.

2. *Indian Point Nuclear Generating Unit No. 3, Updated Final Safety Analysis Report* (UFSAR), Section 1.3.1, General Design Criteria, Fire Protection (Criterion 3).

3. 10CFR50.48, *Fire Protection.*

4. 10CFR50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979.*

5. Branch Technical Position (BTP) 9.5-1 and Appendix A to BTP 9.5-1, Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976.

6. NRC Generic Letter 81-12, *Fire Protection Rule* (45 FR 76602, November 19, 1980), February 20, 1981.

7. NRC Generic Letter 85-01, *Fire Protection Policy Steering Committee Report*, January 9, 1985.

8. NRC Generic Letter 86-10, *Implementation of Fire Protection Requirements*, April 24, 1986.

9 WCAP-10541, *WOG Report Reactor Coolant Pump Seal Performance Following a Loss of All AC Power*, Rev. 2, November 1986

10.2 Generic Letter 89-10 Motor-Operated Valve Program

In June 1989, the NRC issued Generic Letter (GL) 89-10 (Reference 1) to address concerns noted in achieving reliable operation of applicable motor-operated valves (MOVs). Generally, safety-related valves and other valves determined to be important to safety are required to be included in this valve program. GL 89-10 requires that safety-related MOVs be analyzed and controlled to ensure they are capable of performing their required functions. IP3 has established a GL 89-10 MOV Program.

Generic Letter 96-05 (Reference 2) supersedes GL 89-10 with respect to MOV periodic verification, and requests licensees verify on a periodic basis that safety-related MOVs continue to be capable of performing their safety functions within the current licensing bases of the facility. The requirements of GL 96-05 are incorporated into the IP3 GL 89-10 MOV Program.

Generic Letter 89-10, Supplement 6 required an evaluation of the potential for pressure locking and thermal binding of motor-operated gate valves. GL 95-07 (Reference 3) expanded the scope to include all power-operated gate valves within the design and licensing basis. This issue is addressed in Section 10.10 of this report.

In conformance with GL 89-10 requirements, a differential pressure calculation has been issued for each MOV in the GL 89-10 MOV Program. The following parameters are determined in these calculations:

- Maximum design basis opening and closing differential pressure
- Maximum design basis opening and closing line pressure

The results of the MOV differential pressure calculations are used as inputs in other GL 89-10 Program MOV calculations, for example, analysis of MOV thrust and torque limits.

The evaluations of MOV motor-torque degradation due to elevated ambient temperatures utilize temperature data from the Electrical Equipment Environmental Qualification (EQ) Program.

Evaluation of the impact of the SPU on the differential pressure calculations for GL 89-10 MOVs in balance-of-plant (BOP) systems shows that the SPU has no impact on the maximum differential pressures/line pressures determined in the current MOV differential pressure calculations for MOVs in the Main Feedwater System (refer to Section 9.4 of this report).

For MOVs in the Nuclear Steam Supply System (NSSS) systems (that is, Reactor Coolant System [RCS], Chemical and Volume Control System [CVCS], Residual Heat Removal System [RHRS], Component Cooling Water System [CCWS], and Safety Injection System [SIS], the

changes in system flows, pressures, and temperatures resulting from the SPU have been documented. Changes in NSSS system parameters resulting from the SPU do not affect the conclusions of the MOV Program for MOVs in NSSS Systems.

The impact of the SPU on peak ambient temperatures in plant locations containing environmentally qualified equipment is addressed in Section 10.8 of this report. Review of the environmental data in this section shows that accident peak ambient temperatures under SPU conditions are bounded by the accident peak ambient temperatures under existing (pre-uprate) conditions. Accordingly, the SPU does not affect the results of current evaluations of MOV motor-torque degradation due to elevated ambient temperatures.

The SPU does not impact the schedule for periodic verification of MOV settings per GL 96-05.

10.2.1 References

1. NRC Generic Letter 89-10, *Safety-Related Motor Operated Valve Testing and Surveillance*, June 28, 1989, and supplements.

2. NRC Generic Letter 96-05, *Periodic Verification of Design Basis Capability of Safety-Related Motor-Operated Valves*, September 18, 1996.

3. NRC Generic Letter 95-07, *Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves*, August 17, 1995.

10.3 Flow-Accelerated Corrosion Program

Flow-accelerated corrosion is a form of material degradation that results in thinning the inside pipe wall in carbon steel piping and fittings under certain flow and chemistry conditions. Undetected FAC-induced wall thinning may cause a pipe to leak or rupture, causing personnel injury and/or plant shutdown. For these reasons, and in response to regulatory requirements (References 1 and 2) and *Updated Final Safety Analysis Report* (UFSAR) (Reference 3) commitments, IP3 has developed and implemented a program to monitor and mitigate FAC in plant piping.

For the following large-bore, high-energy piping systems, the Electric Power Research Institute (EPRI) computer program CHECWORKS is used to predict erosion rates for each modeled component within each system. The specific lines and fittings in these systems that are included in the FAC Program are identified in the applicable large bore calculation and report and shown on the applicable isometric drawings.

- Heater drains
- Extraction steam
- Feedwater
- Condensate
- Reheater drains
- Moisture separator drains
- Moisture pre-separator drains

The IP3 Small Bore and Augmented Monitoring Program addresses piping that has not been modeled using CHECWORKS. The majority of these lines are small bore lines (defined as all socket-welded piping, and all butt-welded piping less than or equal to 2 inches nominal pipe size). Also included is a subgroup of large bore lines, which would normally be exempt from modeling using the CHECWORKS criteria. This program identifies lines in the following systems that are recommended for inspection:

- Heater drains and vents
- Moisture separator reheater (MSR) drains and vents
- Feedwater
- Steam generator blowdown
- Main steam
- Extraction steam
- Heater drains
- Gland seal steam
- Condensate

The Auxiliary Feedwater System (AFWS) and Auxiliary Steam System are also currently included within the scope of the FAC Program.

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 (MSS), Extraction Steam System (ESS), and Steam Generator Blowdown System (SGBS). Evaluations of the impact of the SPU on FAC for the piping in these systems were performed. The following are the key elements of these evaluations:

- Calculation and documentation of piping velocities for lines and equipment nozzles in the system, including lines in IP3 FAC Program. Piping velocities under SPU conditions in drain lines were calculated as single-phase (water) flow.

- Comparison of the calculated piping and nozzle velocities with standard industry velocity criteria as a measure of whether there was an increased potential for FAC.

- Evaluation of any effect of calculated operating temperatures under SPU conditions on FAC in pipelines and nozzles.

Major results and conclusions from these evaluations are summarized as follows (details are included in Sections 9.1, 9.2, 9.3, 9.4, and 9.5):

- The majority of piping and nozzle velocities under SPU conditions are within the standard industry criteria. Many of these lines are included in the IP3 FAC Program.

- Most of the pipelines and nozzles that had velocities exceeding the standard industry criteria are included in the IP3 FAC Program or have been removed from the FAC Program due to piping material upgrade.

- The velocities in feedwater heaters 31A, B and C condensate inlet nozzles and heater drain outlet nozzles exceed Heat-Exchange Institute (HEI)-recommended velocities. However, these nozzles are part of single-phase lines that are below the low temperature limit for FAC susceptibility. Therefore, these lines are excluded from the FAC Program.

- Based on a review of changes in operating temperatures due to the SPU, the operating vent lines for feedwater heaters 32A, B, and C will be added to the FAC Program.

The CHECWORKS models will be updated to incorporate flow and thermal performance data at SPU conditions.

10.3.1 References

1. NRC Bulletin No. 87-01, *Thinning of Pipe Walls in Nuclear Power Plants,* July 9, 1987.

2. NRC Generic Letter 89-08, *Erosion/Corrosion – Induced Pipe Wall Thinning.*

3. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report,* Rev. 18, Docket No. 50-286, Section 10.4, "Tests and Inspections."

10.4 Flooding

10.4.1 Internal Flooding Outside Containment

In response to an NRC request, IP3, determined if failure of any non-Category I (seismic) equipment could result in a condition that might potentially adversely affect the performance of safety-related equipment required for safe shutdown or for limiting the consequences of an accident (Reference 1). The review consisted of determining the seismic Class III (non-seismic) lines in the Diesel Generator Building, containment, Fuel Handling Building, service water pump area, Control Building, Turbine Hall, Primary Auxiliary Building (PAB), and the auxiliary feedwater pump room, and assessing the flooding potential from each line.

IP3 performed a systems interaction study that addressed flooding from failure of Seismic Class II and III lines in the PAB, Control Building, Diesel Generator Building, and the Auxiliary Feedwater Building. Flooding from failure of Seismic Class II and III lines is also addressed in the UFSAR (Reference 2), Section 16.1.3, "General Seismic Design Criteria and Damping Values, Effects of Failure of Class III Equipment on Safety-Related Equipment."

Evaluation results include the following, along with discussion of the impact of the SPU on results:

Circulating Water System

A barrier is installed at the doorway to the switchgear room to provide protection from flooding up to Elevation 19'. Therefore, flooding from the Circulating Water System (CWS) in the turbine hall could not affect the performance of the 480-V switchgear located in the Control Building at Elevation 15'. Since the CWS is an open system with no valves, and therefore no means of producing a high dynamic head, the probability of a failure is very small. However, to ensure that the 480-V switchgear would not be adversely affected from flooding, redundant level alarm switches were installed in the pipe tunnel at Elevation 3'-3" of the turbine hall. These switches sense high water in the pipe tunnel and have indication in the control room. The operators have time to investigate any flooding problem and take appropriate action by shutting down the circulating water pumps to prevent flooding to Elevation 19'.

There are no CWS flow rate changes or system modifications resulting from the SPU. Therefore, the analysis of flooding from this system in the turbine hall is not affected by the SPU.

Auxiliary Feedwater Pump Room

Evaluation of the auxiliary feedwater pump room, located between the containment and the shield wall, revealed that safety-related equipment would not be affected by failure of the Seismic Class III portion of the MSS. Performance of the auxiliary feedwater (AFW) pumps could be adversely affected if the water reached Elevation 19'-8" in the auxiliary feedwater pump room. To preclude flooding of the AFW pump motors under the worst postulated conditions of main feedwater line failure, modifications were made to the AFW Building exterior doors to provide openings (called "flood control gates") at the bottom of the doors.

Failure of the main feedwater lines, located above and outside of the auxiliary feedwater pump room, would result in water accumulating at the 18'-6" elevation. Feedwater pump flow increases above the current flow at 100-percent power under SPU conditions. However, the following features preclude flooding of the AFW pump motors in the pump room under SPU conditions:

- Flood water from the area adjacent to the auxiliary feedwater pump room containing the feedwater lines would only propagate into the pump room through an interconnecting door with a small gap at the bottom of the door. Flood water would drain to the yard via a door equipped with a flood control gate (approximately 8 inches by 32 inches).

- Flood water in the area containing the feedwater lines would drain to the yard via a door equipped with a flood control gate (approximately 8 inches by 26 inches).

Primary Auxiliary Building

Performance of the residual heat removal (RHR) pumps located at Elevation 15' of the PAB would be affected by flooding only if the water level reached Elevation 19'. Analysis showed that approximately 120,000 gallons of water would be required to cause flooding to this elevation, considering pipe breaks in Seismic Class III lines in the Auxiliary Steam System, SGBS, Waste Disposal System, Auxiliary Coolant System, and City Water System, and Seismic Class II lines in the Primary Water System. Analysis results showed that it would take almost 10 hours for the water level to rise approximately 3.5 feet at the 15' elevation. The major contributors to this result were postulated ruptures in Seismic Class II primary water lines. Although the ten hour time period provides sufficient time for operator action to prevent flooding to Elevation 19' of the PAB, modifications were made to assure there is adequate drainage area to preclude flooding of the RHR pumps in the unlikely event that postulated flooding was not discovered.

The only lines in the PAB flooding evaluation affected by the SPU are the SGBS Seismic Class III lines. The nominal blowdown flow under SPU conditions can increase in proportion to the SPU increase in feedwater flow (approximately 6 percent) to the steam generators. However, this relatively small increase in flow would not significantly affect the conclusions of the evaluation of flooding in the PAB due to failure of non-Seismic Class I piping.

10.4.2 Flooding Inside Containment

The submergence level inside containment resulting from a postulated loss-of-coolant accident (LOCA), documented in the IP3 Environmental Qualification Program, is at Elevation 50'-1.5", which is 4 feet – 1½ inch above the containment floor level.

The SPU does not affect the water inventories of the Reactor Coolant System (RCS), residual water storage tank (RWST), spray additive tank, or safety injection (SI) accumulators. Accordingly, the flood level inside containment documented in the EQ Program Plan will not be impacted by the SPU.

10.4.3 References

1. Letter from Consolidated Edison Co. of NY to the NRC, January 23, 1973.
2. *Indian Point Nuclear Generating Unit No. 3 – Updated Final Safety Analysis Report*, Rev. 18, Docket No. 50-286.

10.5 Probabilistic Safety Assessment

A Probabilistic Safety Assessment (PSA) is a useful tool for a quantitative and qualitative assessment of the likelihood and consequences of damage that could potentially result from events occurring during plant operation.

The model used in the IP3 PSA analyses is maintained and updated in accordance with plant procedures. Plant modifications that have the potential to significantly effect core damage frequency (CDF) or large early release frequency (LERF) are evaluated and incorporated, as appropriate, into the model following implementation of the change.

The effect of the SPU on the IP3 PSA will be evaluated, including the effect of plant modifications due to the SPU. The PSA "levels" to be addressed for the IP3 SPU are in accordance with existing procedures.

10.6 Station Blackout

The SBO Rule, 10CFR50.63 (Reference 1), 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 Regulatory Guide (RG) 1.155 (Reference 2) to provide guidance in responding to the SBO Rule. This RG endorses a publication of the Nuclear Management and Resource Council (NUMARC), NUMARC 87-00 (Reference 3). Regulatory Guide 1.155 and NUMARC 87-00 were utilized in evaluating SBO at IP3.

The Appendix R Diesel Generator serves as the alternate AC (AAC) power source at IP3. The IP3 Appendix R Diesel Generator load analysis determines the capability of the Appendix R Diesel Generator to provide power requirements during hot shutdown above RHR conditions. 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 is determined to be 8 hours.

Evaluation of Appendix R Diesel Generator load requirements for an SBO event under SPU conditions shows that there are no significant load increases that would affect the conclusions of the current Appendix R Diesel Generator load analysis.

The IP3 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
- Reactor coolant inventory

The following is a discussion of the effect of the SPU on the plant capabilities for coping with an SBO event for each of these topics.

Condensate Inventory for Decay Heat Removal

The condensate inventory for decay heat removal was determined using the methodology in NUMARC 87-00, which provides a bounding analysis for assessing condensate inventory. The *Technical Specifications* require that a minimum of 360,000 gallons of water must be available in the condensate storage tank (CST) during plant operation above 350°F. For the SPU, the volume of water required for 8 hours of decay heat removal and primary system cooldown was determined; the results show that there is adequate margin between the minimum required volume of water in the CST and the volume of water required for coping with an SBO event.

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, and that there is no need to modify existing SBO loads that require 125-VDC control or motive power. Accordingly, the station batteries have sufficient capacity to meet SBO loads for one hour under SPU conditions.

Compressed Air

Based on existing plant SBO analyses and associated NRC safety evaluations:

- Air-operated valves (AOVs) 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.

- The turbine-driven AFW pump steam supply valve can be operated manually. The turbine-driven AFW pump (TDAFWP) speed control valve has nitrogen back-up and can be operated manually.

- The turbine-driven AFW pump flow control valves have nitrogen back-up and can be operated manually. Regarding habitability in the AFW pump room for local operation of these valves, it is expected that AFW flow will be established within a time period such that the temperature rise up to this time is not expected to make habitability a concern.

- The atmospheric relief valves (ARVs) have two back-up supplies: a common nitrogen supply, and dedicated nitrogen bottles, which are lined-up manually. Habitability is not a concern for the short duration required to line up the back-up nitrogen bottles.

- All other AOVs are designed to fail in the correct or safe position.

- The SPU does not affect these evaluation results.

Effects of Loss-of-Ventilation

The AFW pump room was identified as the only dominant area of concern. The temperatures used in the analysis of AFW pump room temperatures after an SBO envelop the steam conditions used as inputs for the SPU analyses associated with the TDAFWP, and therefore the SPU does not affect the current AFW pump room analysis results.

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

Containment Isolation

Based on existing plant SBO analyses and associated NRC safety evaluations:

- A total of 19 containment isolation valves (CIVs) were identified that could not be excluded based on the five criteria given in RG 1.55 (Reference 2), (for example, valves normally locked closed during operation). Rationale was provided for accepting these valves without modification as providing the required containment integrity during an SBO event. 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.

- Except for the containment air lock door equalizing valves, plant procedures provide instructions for closing these CIVs if necessary. Because the inner and outer air lock doors are mechanically interlocked so that only one door will be open at any one time, and the door equalizing valves are interlocked with their respective air lock door, only one air lock door equalizing valve will be open at any one time.

The SPU does not affect these evaluation results.

Reactor Coolant Inventory

IP3 assessed the ability to maintain adequate RCS inventory for the coping duration of the SBO event in accordance with NUMARC 87-00 (Reference 3), Section 2.5.2. The reactor coolant inventory calculation is based on an RCS inventory loss of 25-gpm seal leakage per RCP, 11-gpm *Technical Specification* leakage, and 120-gpm letdown leakage for 10 minutes. The AAC power source, which will be available 1 hour after onset of an SBO, will provide power to a charging pump with a capacity of 98 gpm to offset inventory loss and keep the core covered for the entire 8 hour coping duration.

The SPU does not affect these evaluation results.

In a Safety Evaluation dated December 23, 1991, the NRC stated that the 25-gpm seal leakage per RCP was agreed to between NUMARC and the NRC pending resolution of Generic Issue (GI) 23, "Reactor Coolant Pump Seal Failure," and if the final resolution of GI 23 defined higher RCP leakage rates, the reactor coolant inventory analysis could be affected accordingly. However, in a letter to holders of operating licenses in February 2000 (Reference 4), the NRC stated that the staff concluded that no additional generic requirements should be proposed and licensees should not be required to revise the current deterministic SBO coping analysis assumptions, and that GI 23 is closed.

10.6.1 References

1. 10CFR50.63, *Loss of All Alternating Current Power*, June 21, 1988.

2. NRC Regulatory Guide 1.155, *Station Blackout*, August 1, 1988.

3. NUMARC 87-00, *Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout and Light Water Reactors*, November 1987.

4. NRC Letter, *NRC Regulatory Issue Summary 2000-02, Closure of Generic Safety Issue 23, Reactor Coolant Pump Seal Failure*, February 15, 2000.

10.7 In-Service Inspection/In-Service Testing Programs

10.7.1 In-Service Inspection Program

The following inspection programs, required by the *ASME Boiler and Pressure Vessel Code* (Reference 1), Section XI, are implemented at IP3.

- In-Service Inspection (ISI) Program for inspections of ISI Class 1, 2, and 3 piping systems.
- ISI Containment Program for inspections of ISI Class MC and CC components.

Classification of systems and components as ISI Class 1, 2, 3, MC, and CC is performed in accordance with RG 1.26 (Reference 2), 10CFR50.55a (Reference 3), and NRC rulemaking. Inservice inspection of these systems and components is performed in accordance with ASME Code of Record requirements.

The IP3 "Inservice Inspection Program, Third Ten-Year Interval" details the ISI plan and schedule for ISI Class 1, 2, and 3 components, piping, and their supports. This plan will be conducted in accordance with the *ASME Boiler and Pressure Vessel Code*, Section XI – 1989 Edition with no Addenda (Reference 1), with exceptions as noted in the implementing IP3 document. Augmented inspections are performed as required by 10CFR50.55a (Reference 3), the NRC, or as deemed necessary by the ISI Program.

For modifications required in support of the SPU, the effect of the changes on the ISI Program will be evaluated as part of the engineering change process.

10.7.2 In-Service Testing Program

The purpose of the In-Service Testing (IST) Program is to assess the operational readiness of selected pumps and valves to perform a specific function. The pumps and active/passive valves covered under the program are those which are required to perform a specific function in mitigating the consequences of an accident, or shutting down and maintaining the reactor in a safe shutdown condition.

The IP3 IST Program for pumps and valves is implemented by plant procedures, as required by the *ASME Boiler and Pressure Vessel Code*, Section XI (Reference 1), ASME/ANSI OM Part 6 (Reference 4) and Part 10 (Reference 5), and *Technical Specification* 5.5.7 (Reference 6). The program is applicable to IST of pumps and valves for IP3's third 10-year inspection interval (July 21, 1999 to July 21, 2009). The IST Program is integrated into the IP3 Surveillance

Program and is governed by the scheduling, conduct of testing, and equipment operability review requirements of this program.

For modifications required in support of the SPU, the effect of the changes on the IST Program will be evaluated as part of the engineering change process.

10.7.3 References

1. *ASME Boiler and Pressure Vessel Code*, Section XI, 1989 Edition, The American Society of Mechanical Engineer, New York, NY.

2. NRC Regulatory Guide 1.26, Rev. 3, Quality Group Classifications and Standards for Water, Steam, and Radioactive Waste – Containing Components of Nuclear Power Plants.

3. 10CFR50.55a, *Codes and Standards.*

4. ASME/ANSI Operations and Maintenance Standard, Part 6 (OM-6), *In-Service Testing of Pumps in Light Water Reactor Plants*, 1987 Edition.

5. ASME/ANSI Operations and Maintenance Standard, Part 10 (OM-10), *In-Service Testing of Valves in Light Water Reactor Plants*, 1987.

6. IP3 Technical Specification 5.5.7, *In-Service Testing Program*, Amendment No. 205.

10.8 Electrical Equipment Environmental Qualification Program

10.8.1 Introduction

The electrical equipment that is covered by the Electrical Equipment EQ Program has been reviewed for effects to its qualification as a result of the Indian Point Unit 3 (IP3) stretch power uprate (SPU). The review has been performed primarily by comparison of the new accident temperatures and radiation dose associated with the uprate to environmental conditions in the EQ Program.

The environmental parameters of pressure, humidity and chemical spray, and submergence are also addressed.

10.8.2 Environmental Parameters Inside Containment

The SPU has no effect on the qualification of equipment inside containment with respect to the temperature, but does have an impact with respect to qualifying the radiation dose.

10.8.2.1 Normal Operating Temperature

The temperature during normal operation is unchanged. The qualified life of all EQ equipment inside the containment is unchanged.

10.8.2.2 Accident Temperature

The pre-uprate accident temperature profile used for the EQ Program with a peak of 261.5°F bounds the containment re-analysis temperature profile with a peak of 260.4°F from the LOCA. IP3 does not use the main steamline break (MSLB) inside containment as a basis for EQ since it is licensed to Division of Operating Reactors (DOR) EQ requirements. Therefore, a composite LOCA/MSLB temperature profile is not evaluated for the SPU review of EQ.

The equipment inside containment remains qualified on the existing bases for the temperature conditions associated with the SPU.

10.8.2.3 Accident Pressure

The LOCA pressure inside containment is bounded by the EQ pressure profile.

The equipment inside containment remains qualified on the existing bases for the pressure conditions associated with the SPU.

10.8.2.4 Radiation

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 (TID) for 40-year normal operation and accident of 2.01 $x10^7$ rads increases the radiation doses for several equipment types.

An evaluation of the exposure of the critical radiation-sensitive parts was made for selected equipment for the beta dose. It was concluded that the affected equipment remains qualified. This analysis took into account the installation configuration of the equipment with respect to gamma and beta shielding and the construction of the equipment with respect to self-shielding against beta radiation. All equipment was determined to be acceptable for use within the requirements of the EQ program.

10.8.2.5 Submergence

Flood level inside containment is discussed in Section 10.4 of this report. The cables in the EQ Program inside containment are qualified for submergence. Radiation doses to submerged cables increase as a result of the SPU and the fuel cycle change.

To provide the SPU qualification for submergence, a scaling factor was applied for the SPU, and the normal 40-year operating dose for 3216 MWt added. All potentially submerged cables are qualified for the SPU with large margins.

10.8.2.6 Humidity

The normal and accident humidity has not been affected by the SPU.

10.8.2.7 Chemical Spray

The spray and sump water chemistry has been marginally affected by the SPU. The slight change of a fraction of a pH level is within the range of pH values covered in the EQ Program prior to SPU.

10.8.3 Environmental Parameters Outside Containment

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 penetration area. There is also a small increase in the radiation levels for the SPU due to the recirculation of reactor coolant or sump water.

10.8.3.1 Normal Operating Temperature

The temperature during normal operation is unchanged.

10.8.3.2 Accident Temperature

The three bounding high-energy line breaks (HELBs) for EQ equipment outside containment are:

- The MSLB in the steam and feedline penetration area
- The main steam supply line to the turbine drive of the auxiliary feedwater (AFW) pump in the AFW pump room
- The steam generator blowdown line break in the pipe penetration area

Main Steam to Auxiliary Feedwater Pump Turbine HELB

The existing HELB temperature analysis bounds the conditions of the SPU.

Steam Generator Blowdown Line HELB

A check of process conditions was performed to determine the effect of the SPU on the steam generator blowdown line break. The Zaloudek correlation was used to compare the blowdown conditions that have been used for the existing EQ to the conditions that will be present for the SPU.

The critical flow under the SPU conditions is 4.4 percent less than the pre-SPU conditions. The difference in the mass and energy (M&E) release is considered by engineering judgment within the conservatism in the M&E release analysis and, therefore, no change in the accident temperatures is necessary.

All equipment located in the areas that are affected by the steam generator blowdown HELB that were qualified remain qualified.

Equipment in the Primary Auxiliary Building, such as the RHR pumps and the safety injection (SI) pumps, are in areas where there is no HELB effect. The only harsh environmental parameter is the LOCA radiation dose from the recirculated sump or reactor vessel water. The accident temperature is the same as the normal temperature.

MSLBs in Steam and Feedline Penetration Area

A spectrum of MSLBs have been reanalyzed for the SPU (see subsection 6.6.4). The peak accident temperature for the break building area is above the qualification temperatures for the EQ equipment in these areas, however, it is bounded by the pre-SPU HELB temperatures.

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 limiting break for equipment qualification was identified as a 1-ft^2 break. The equipment in the steam and feedline penetration area is qualified considering the thermal lag analysis.

10.8.3.3 Radiation

The SPU effect on radiation outside containment has been evaluated. The beta radiation dose to EQ equipment outside containment is negligible. The radiation sources are inside process equipment and piping. In the event of a LOCA inside containment, the highly radioactive water is recirculated within process equipment and piping in the Primary Auxiliary Building and pipe tunnel. This water has a slightly higher radiation dose than before the SPU, but the effect on EQ is acceptable.

10.8.3.4 Humidity

The SPU does not change the normal operational humidity or the accident humidity outside containment.

10.8.3.5 Flooding

Flooding outside the containment is addressed in Section 10.4 of this document.

10.8.4 SPU Equipment Qualification Evaluation

Equipment Inside Containment

All equipment inside reactor containment is qualified for SPU conditions when the considerations discussed earlier in subsection 10.8.2 are made.

The equipment qualified life and post-accident operability time are not impacted by the SPU.

Equipment Outside Containment

Accident temperatures outside containment in the steam and feedline penetration area have been re-analyzed and result in lower temperatures. All other areas outside containment experience insignificant temperature increases. All equipment outside containment required for accident response has been verified to be qualified.

10.9 Chemistry Program

10.9.1 Primary Chemistry Program

The IP3 Primary Strategic Water Chemistry Plan establishes a site-specific chemical program for minimizing corrosion damage and maintaining system and fuel cladding integrity in the RCS, as well as keeping ex-core dose rates as low as possible. This plan satisfies the requirements for the primary water chemistry component of NEI 97-06, *Steam Generator Program Guidelines* (Reference 1), which directs licensees to comply with the intent of EPRI's, *PWR Primary Water Chemistry Guidelines* (Reference 2).

As addressed in subsection 4.1.2.1 of this report, the IP3 SPU results in relatively small temperature changes in primary and secondary coolant temperatures and these new operating conditions are well within the envelope of conditions used in developing the industry chemistry guidelines. Therefore, the IP3 plant chemistry limits based on industry guidelines are still applicable after the IP3 SPU, and no changes to the Primary Chemistry Program are required for the IP3 SPU.

10.9.2 Secondary Chemistry Program

The goal of the IP3 Secondary Strategic Water Chemistry Plan is to minimize chemically induced corrosion damage and performance degradation in the secondary water system. This plan is required by NEI 97-06, *Steam Generator Program Guidelines* (Reference 1). With respect to the secondary water chemistry component of the Steam Generator Program, NEI 97-06 directs licensees to comply with the intent of EPRI's, *PWR Secondary Water Chemistry Guidelines* (Reference 3). As addressed in IP3 *Technical Specification* 5.5.9 (Reference 4), a specific objective of the Secondary Water Chemistry Program is to provide controls for monitoring secondary water chemistry to inhibit steam generator tube degradation.

The original steam generators at IP3 were replaced in 1989 with Westinghouse Model 44F steam generators containing thermally treated U-tubes fabricated from Alloy 690. Subsection 5.6.7 of this report addresses the impact of the SPU on the potential for stress corrosion cracking (SCC) and pitting of the Alloy 690 tubing.

10.9.3 References

1. Nuclear Energy Institute (NEI) 97-06, Steam *Generator Program Guidelines*, Rev. 1, January 2001.

2. EPRI TR-105714-V1R4, *PWR Primary Water Chemistry Guidelines*, Volume 1, Rev. 4.

3. EPRI TR-102134-R5, Final Report, *PWR Secondary Water Chemistry Guidelines*, Rev. 5.

4. *IP3 Technical Specification*, No. 5.5.9, "Secondary Water Chemistry Program," Amendment No. 205.

10.10 Generic Letter 95-07

In 1995 the NRC issued Generic Letter 95-07 (Reference 1), requesting that certain actions be taken by utilities regarding the susceptibility and evaluation of power-operated gate valves to the phenomena of pressure locking and thermal binding. Power-operated valves include safety-related MOVs and AOVs.

Based on recognition of the potential for pressure locking, a number of motor-operated gate valves were field-modified prior to initial startup to eliminate the potential for pressure locking. Similar modification of additional MOVs was performed after startup. The normal positions of two MOVs were changed utilizing the 10CFR50.59 (Reference 2) process from closed to open to eliminate the potential for pressure locking.

Results of the screening of safety-related motor-operated gate valves identified the MOVs that required detailed evaluations for susceptibility to pressure locking and/or thermal binding. The evaluations considered two types of pressure locking: hydraulically induced pressure locking and thermally induced pressure locking. These detailed evaluations showed that: the MOV actuators have sufficient thrust to open the valves under the prescribed conditions, or based on detailed analysis, pressure locking and/or thermal binding is not a concern or the valves are acceptable in the current condition.

By screening gate valves with attached hydraulic/pneumatic actuators, two AOVs that are potentially susceptible to pressure locking and/or thermal binding were identified. These valves are not susceptible to thermal binding due to valve design. An evaluation of the susceptibility of the AOVs to pressure locking determined that pressure locking is not a concern due to their normal position of open and procedural guidance given in event of their closure.

The impact of the SPU on the pressure locking and thermal binding evaluations of MOVs/AOVs was reviewed. It was determined that the SPU does not introduce any increased challenge for pressure locking and/or thermal binding and does not impact the results and conclusions of the current evaluations.

10.10.1 References

1. NRC Generic Letter 95-07, Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves, August 17, 1995.

2. 10CFR50.59, *Changes, Tests, and Experiments.*

10.11 Generic Letter 96-06

Generic Letter 96-06 (Reference 1) requested that nuclear utilities address the susceptibility of containment air cooler cooling water systems to either water-hammer or two-phase flow conditions during postulated accident conditions, and piping systems that penetrate containment to thermal expansion of fluid such that overpressurization of piping could occur.

In response to GL 96-06, IP3 performed evaluations of:

- Thermally induced overpressurization of isolated water-filled piping sections
- Water-hammer associated with containment fan cooler units (FCUs)
- Two-phase flow conditions associated with the FCUs.

Summary of major results/conclusions of these evaluations and the impact of the SPU on the results/conclusions follows.

Thermally Induced Overpressurization

The containment penetration configurations were evaluated, and the lines and associated CIVs determined to be potentially susceptible to thermal pressurization resulting from containment LOCA and/or PAB HELB conditions were identified. These lines and associated CIVs were determined to be acceptable based on one of the following:

- Line contains AOVs that would self-relieve pressure prior to exceeding design code or UFSAR faulted condition stress limits

- Line/CIVs meet design code normal condition stress acceptance criteria

- Line/CIVs meets faulted condition stress limits allowed by the UFSAR

A generic containment temperature effect evaluation was performed to confirm that CIVs outside containment, and the piping between these valves, would not be significantly affected by elevated containment temperatures.

An evaluation review of the lines and associated CIVs determined to be potentially susceptible to thermal pressurization from containment LOCA and/or PAB HELB conditions for impact of the SPU was performed. the SPU does not affect the results and conclusions of these evaluations, based on the following:

- The maximum temperature utilized for structural evaluation of lines and CIVs subject to containment LOCA conditions envelopes the peak containment temperature for a LOCA under SPU conditions.

- The structural evaluation of lines and CIVs subject to PAB HELB conditions is not affected by the SPU since, as indicated in Section 10.8 of this report the peak temperature in the PAB pipe penetration area resulting from a HELB under SPU conditions is bounded by the peak temperature due to a HELB under existing (pre-uprate) conditions.

Water-Hammer

All Service Water System (SWS) supply and return lines to the five containment FCUs were analyzed for postulated water-hammer loadings. Two type of water-hammer events were determined to occur: column-closure caused by a LOOP event or a simultaneous LOOP and LOCA event, and steam-condensation-induced (void collapse) caused by simultaneous LOOP and LOCA events. Evaluations and assessments encompassed hydraulic system response, system monitoring during a simulated SI test, system walkdowns to visually observe the structural condition of the piping and support system, and structural assessments. Based on the analytical work performed, consideration of actual measured data during a simulated SI, present system condition, and modification of pipe supports, it was concluded that the containment service water (SW) piping and FCUs are capable of withstanding the postulated water-hammers events that can occur either during LOOP, or LOOP with LOCA events within the design basis acceptance criteria in the UFSAR.

The impact of SPU conditions on GL 96-06 SWS water-hammer issues was evaluated. It was concluded that the column closure water-hammer and the steam-condensation-induced (steam bubble or void collapse) water-hammer will not be significantly impacted by the small (less than 1 percent) decrease in accident peak containment temperature and/or the small expected increase in containment FCU cooling water outlet temperature under SPU accident conditions. That is, the velocity (critical parameter) of column closure and the volume (critical parameter) of steam bubble formation are not significantly affected by these small changes in temperatures.

Two-Phase Flow

Based on evaluations, it was concluded that the IP3 SWS and containment FCUs will remain operable and perform their design accident functions with the single failures considered during the original design and licensing with two-phase flow occurring at the manual isolation valves in the SW piping downstream of the FCUs, outside of containment. This two-phase flow condition will result in reduced SW flow to the FCUs. However, the predicted reduction in SW flow will not result in reduced FCU heat removal capability below the design basis accident heat removal requirement. Therefore, there is no challenge to either the SWS or FCU operability.

The impact of the SPU on the current evaluation for two-phase flow was reviewed. The inputs that affect the results of the two-phase flow evaluation include SW temperature and the SW flow requirements for the containment FCUs. The SW temperature is affected by containment peak temperature and containment FCU heat load. Under SPU conditions, the containment LOCA peak temperature decreases slightly (refer to Section 10.8), and the containment FCU heat load is enveloped by the original design basis. The SW flow requirement for the containment FCUs is not changed under SPU conditions. Therefore, the SPU does not impact the conclusions of the current IP3 two-phase flow evaluation.

10.11.1 References

1. NRC Generic Letter 96-06, *Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions*, September 30, 1999, and Supplement, November 13, 1997.

10.12 Generic Letter 89-13

Generic Letter 89-13 (Reference 1) identified a number of concerns affecting safety-related equipment associated with SWSs, and put forth recommended actions in the areas of surveillance, testing, inspection, and maintenance to ensure these systems are in compliance with regulations.

The intake structure, SWS, and the following safety-related (Quality Assurance [QA] Category I) essential heat exchangers cooled by the SWS, including associated piping and valves, are included within the scope of GL 89-13 at IP3:

- Control Room AC condenser units
- Containment FCUs
- Containment FCU motor coolers
- EDG lube oil/jacket water coolers
- CCW heat exchangers (HXs)

The GL 89-13 implementation plan at IP3 addresses the following five areas:

1. Surveillance and control techniques to reduce the incidence of flow blockage as a result of bio-fouling: Activities include inspection of the intake structure, chlorination of the SWS, and implementation of an equipment lay-up program for HXs to minimize microbiologically influenced corrosion.

2. Test program to verify heat transfer capability of all safety-related HXs cooled by SW: IP3 has committed to perform frequent periodic cleaning and inspection of essential SW HXs (identified above) in lieu of testing for degraded performance. This is implemented through preventive maintenance procedures for the applicable HXs.

3. Inspection and maintenance program for SW piping and components: The IP3 Preventive Maintenance Program includes major SWS components, such as the SW pumps, Zurn strainers, and various relief and butterfly valves. A continuing corrosion monitoring program has been established for the SWS. This program involves non-destructive examinations of piping components and valves, and visual inspection of internal pipe surfaces.

4. SWS licensing basis review: The SWS Design Basis Document is in place, and a computer hydraulic model of the SWS has been developed to compute flows through various parts of the system. Walkdown inspections of the accessible portions of the SWS are conducted so that the entire system is inspected on a quarterly basis.

5. Maintenance practices, operating and emergency procedures, and training: The SWS is a risk-significant system and is included in the Maintenance Rule effort. An SWS operating procedure has been established and is updated periodically. Training in the SWS is included in the plant operator re-qualification process.

The SPU does not affect the programs, procedures, and activities in place at IP3 in support of implementation of the requirements of GL 89-13. The impact of the SPU on SWS HX heat loads is addressed in Section 9.6 of this report.

Continued cleaning and inspection of all GL 89-13 HXs post-SPU is recommended to ensure that the performance of these HXs remains acceptable following the SPU.

10.12.1 References

1. Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Equipment*, July 18, 1989.

10.13 Plant Simulator

IP3 has a unit-specific simulator, which replicates the plant control room. The simulator computer systems provide simulator responses that are intended to match, to the greatest extent possible, actual plant conditions for the simulation of accidents and transients.

Appendix A to 10CFR55 (Reference 1) permits use of simulators for operator training. Regulatory Guide 1.149 (Reference 2), states that the requirements established by ANSI/ANS 3.5, *Nuclear Power Plant Simulators for Use in Operator Training*, for specifying the functional capability of a simulator and for comparing a simulator to its reference plant are acceptable to the NRC, subject to provisions identified in the Regulatory Guide. The IP3 simulator is currently certified to ANSI/ANS 3.5-1985 (Reference 3).

The implementation of the SPU Program will result in changes in plant operating characteristics (software changes). These changes will range from simple changes in process parameters (for example, flow rates) to changes in plant responses to transients and accidents.

Modifications in support of the SPU will be implemented in accordance with the IP3 engineering change process. This process requires review of the impact of modifications on the IP3 simulator.

10.13.1 References

1. 10CFR55, *Operator Licenses.*

2. NRC Regulatory Guide 1.149, *Nuclear Power Plant Simulators for Use in Operator Training*, April 1981.

3. ANSI/ANS 3.5-1985, *Nuclear Power Plant Simulators for Use in Operator Training.*

10.14 Containment Leakage Rate Testing Program

Appendix J to 10CFR50 (Reference 1) requires that the leakage requirements for a reactor containment specified therein be met. IP3 *Technical Specification* 5.5.15 (Reference 2) specifies that a program should be established to implement the leakage rate testing of the containment as required by 10CFR50.54 (Reference 3) section (o) and 10CFR50, Appendix J, Option B, "Performance-Based Requirements," as modified by approved exemptions. *Technical Specification* 5.5.15 also states that this program should be in accordance with the guidelines in RG 1.163 (Reference 4), as modified by the exceptions noted.

Leakage rate testing requirements are addressed in the IP3 *Technical Specifications* and IP3 Containment Leakage Rate Testing Program procedures.

The results of IP3 design basis accident analyses under SPU conditions show that the calculated peak containment pressure for these accidents, (resulting from the LOCA analysis), is less than the minimum test pressure for leakage rate testing identified in the Containment Leakage Rate Testing Program. Accordingly, the SPU does not impose additional requirements on IP3 containment leakage rate testing.

10.14.1 References

1. 10CFR50, Appendix J, *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.*

2. *Indian Point Unit 3 Technical Specification* 5.5.15, "Containment Leakage Rate Testing Program," Amendment No. 206.

3. 10CFR50.54, *Conditions of Licenses.*

4. NRC Regulatory Guide 1.163, *Performance-Based Containment Leak-Test Program,* September 1995.

10.15 Plant Operations

Entergy does not expect the changes to plant conditions and operation associated with the SPU to result in significant new or increased challenges to plant operations. Entergy recognizes the importance of this element of plant performance and safety and has taken specific actions to address the areas of potential concern. Operations has participated in the preparation and review of changes to the plant and associated operating procedures. Furthermore, appropriate training and simulator changes will be implemented prior to the SPU to ensure operations personnel are familiar with and prepared for any associated changes to the plant response.

10.15.1 Procedures

Although numerous, no significant changes to plant procedures will be required for the SPU. Changes associated with the SPU will be treated in a manner consistent with any other plant modification. The Emergency Operating Procedure (EOP) changes will be made as necessary to reflect the new power level and setpoint changes. The EOP step for addition of supplemental feedwater to steam generators after a trip already exists and has been demonstrated to be accomplished in less than 10 minutes. This procedure will be revised to provide specificity for the flow and time requirements.

10.15.2 Effect on Operator Actions and Training

Engineered Safety Feature System design and procedural controls have not changed with the SPU. Various setpoint changes will be required. However, the operator response to any event will be insignificantly reduced by a change in rated thermal power. The change in hot leg switchover time from 14 hours to 6.5 hours will also have an insignificant effect on operator action and training.

Before SPU implementation, the Nuclear Instrumentation System (NIS), including alarm setpoints, will be adjusted to satisfy new analysis and *Technical Specification* values contained in this report. The operator response to existing alarms remains unchanged.

The changes in operating procedures and setpoints will be part of operator training to be conducted prior to implementation of the SPU.

10.15.3 Plant-Integrated Computer System

Process parameter setpoint and scaling changes will be made, as required, to the Critical Function Monitoring System (CFMS). There are no other changes to the CFMS from the SPU.

10.15.4 Startup Testing

Startup from the refueling outage when plant modifications will be made to accomplish the SPU will be treated as a special evolution. As in the previous uprate for the 1.4-percent MUR, the power escalation will be controlled by a specific procedure. This procedure will detail controls for power escalation, hold points, and data collection requirements (including radiation surveys). Performance monitoring for plant modifications, such as the new high-pressure turbine, will be accomplished at specified power levels. Setpoint changes will be controlled under plant procedure requirements. Monitoring of NSSS plant performance will include monitoring of margins to activation of alarms and trips such as overpower ΔT and overtemperature ΔT. A vibration monitoring activity will be included to monitor plant response at various power levels. The procedure will be subjected to dry runs on the plant simulator to assure plant responses are as predicted. The results of the startup testing will be documented and maintained as plant records.

The IP3 test plan has been prepared to cover both phases of the planned proper increases from the current power level to 3216. The test plan is designed to demonstrate that systems, structures, and components will perform satisfactorily at the SPU condition. The plan provides assurances that:

- The initial power ascension to the Phase 1 SPU power level condition will be controlled.
- The facility can be operated at the proposed SPU condition in accordance with design requirements and in a manner that will not endanger the health and safety of the public.
- The SPU-related modifications to IP3 have been adequately constructed and implemented.
- The Phase 2 power ascension testing will be conducted in a manner similar to the Phase 2 testing program.

A Temporary Operating Instruction (TOI) will be written to control the sequence and coordination of existing plant startup procedures with new post-modification test procedures. It will ensure that the required modifications, calibrations, and specification requirements are in place to support the ascension to full power. Additionally, during the power ascension, the TOI

will be used to callout or to verify the performance of specific test procedures, collection of plant performance data, and documentation of the required reviews. Upon acceptance of plant data and test results, engineering and operations management will document their approval to proceed with the power ascension.

Additionally, post-modification tests (PMTs) for each modification will be performed in accordance with plant design process procedures. The specifics of these PMTs are not detailed herein.

Pre-Startup Activities:

- Material Degradation - Flow-Accelerated Corrosion (FAC) Monitoring Program will be updated for the following areas, affected as a result of SPU:
  - 31ABC and 32ABC FWH
- Additionally, the projected SPU secondary heat balance parameters for temperature, pressures, and velocities will be checked with the CheckWorks FAC Program to ensure that no unanticipated margins are reduced in advance of SPU.

Areas of Increased Monitoring, during Power Ascension

- FWH performance
- Reheat moisture separator drains, potential slug flows/vibrations
- Margin to OP/DT and OT/DT alarm/trip setpoints
- Heater drain pump runout and discharge valve control stability
- Main boiler feed pump speed control circuit:
  - Main feed regulator valve Delta P program circuit
  - Main feed regulator final valve position (lift)
- Flow induced vibration (FIV) on main, reheat, exhaust steam systems
- FIV on condensate/feedwater and heater drain pump systems
- Plant operating control system performance

Piping Vibration Test Plan

In response to feedback from other plants' power uprate efforts, Entergy developed a piping vibration (PV) test plan. This PV plan considered plant condition reports written on piping vibration or support problems and plant piping and support evaluations or calculations for the effects resulting from SPU operating conditions. Based on this review, the following IP3 piping systems, affected by flow increases associated with SPU, were visually observed to determine if any existing pre-uprate vibration concerns exist.

- Main Steam System
- Extraction Steam System
- Feedwater Heater Drains and Vents
- Moisture Separator and Reheater Drains
- Boiler Feedwater System
- Condensate System

As a follow-up to the above pre-uprate visual observations, walkdowns will be conducted during the increase to SPU power. The acceptance criteria to be used during these walkdowns are intended to initially accept piping based on displacement or velocity screening criteria (based on observations of piping systems), and to collect data.

IP3 SPU Test Plan

The following tables describe the testing and data collection for the SPU, related modifications and areas of increased monitoring. The test number to be performed on Table 10-2 is referenced on Table 10-3 at the respective power levels.

10.15.5 References

1. ASME OM-S/G-1994, *Standards and Guides for Operation and Maintenance of Nuclear Power Plants*, 1994.

Table 10-2 Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
HP Turbine	Replace the HP turbine steam path	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Over-speed setting test 3 - Demonstration of thermal performance improvements and generator increase.
Turbine Inlet Steam Pressure	Two pressure tap relocations from turbine 1st stage to inlet control stage (downstream of Governor valves)	1 - Post-modification test 2 - Monitoring of turbine inlet steam pressure during ascension versus projection at hold points for plant calorimetric at 90%, 96.8%, and 100%. Engineering evaluate deviations prior to power ascension approval.
LP Turbine	No modification planned	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Demonstration of thermal performance.
Moisture Separator Reheaters	Replacement of lower separator baskets with counter flow chevron design	1 - Establish as-found base line vibration data at current power level 3067.4 MWt 2- Monitor for flow induced vibrations during power ascension versus as-found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitoring during power ascension steam flow, cross-under; cross-over temperatures and pressures versus projected PEPSE secondary heat balance. Engineering evaluate deviations prior to power ascension approval. 4 - Post-modification test

Table 10-2 (Cont.) Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
Heater Drain System	(mod. not required for SPU)	1 - Monitor HDTP & motors amps; flows and discharge valve lift versus projected. Engineering evaluate deviations prior to power ascension approval. 2 - Monitor for FIVs during power ascension versus as found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitor FWHs levels and terminal drain temperatures versus expected PEPSE heat balance projections.
BOP System Main Steam/Extraction Steam/Reheat Steam/Condensate & Feedwater/ Service Water System	Increase steam and feed flow for Phase 1 power level.	1 - Establish as found base line vibration data at current power level 3067.4 MWt. 2 - Monitor for FIVs during power ascension versus as found. Engineering evaluate deviations prior to power ascension approval. 3 - Monitor for flow induced vibrations post-uprate plus 7 days versus as left. Engineering evaluate deviations and recommend correction as necessary. 4 - Monitor main boiler feed pump speed control; Delta P; feed regulating valve lift, and condensate pump Amps versus expected. Engineering evaluate deviations prior to power ascension approval. 5 - Monitor service water system loads: main turbine generator (MTG) hydrogen coolers, MTG exciter coolers, MTG IPB coolers, temperatures & flows versus established as found base line data at current power level 3114.4 MWt.

Table 10-2 (Cont.) Phase 1 IP3 SPU Power Ascension Testing		
System/Component	**Modification Description**	**Test**
		6 - Monitor FW Hsterminal discharge temperatures versus projected. Engineering evaluate deviations prior to power ascension approval. 7 - Monitor secondary plant oil cooling systems: MBF/CP/HDT/MLO sys. vs. expected and adjust as necessary.
MTG IPB Duct Cooling	No modification planned.	1 - Monitor cooling performance. Engineering evaluate deviations prior to power ascension approval. 2 - *Perform hot spot survey on ducts and* evaluate.
Main Power Transformer Monitoring	Installation of N2 gas monitor	1 - Monitor cooling performance: at minimum and maximum amp/VAR loading versus expected. Engineering evaluate deviations prior to power ascension approval. 2 - Post-modification test for monitoring system.
HHSI Modification	Installation of orifice valves and system re-configuration.	1 - Post-modification test 2 - HHSI system flow balance test
RPS/ESFAS Setpoints	Rescaling transmitters ranges/resetting of NTS	1 - Post-modification test
Control System Setpoints	Rescaling transmitters ranges/resetting of nominal control ranges.	1 - Collect plant data and confirm performance as expected. Evaluate adjustment as required. 2 - Post-modification test
Process Computer	Engineering & alarm value update	1- Perform pre-startup test monitor program functionality during power ascension. 2 - Post-modification test for plant computer update

Table 10-2 (Cont.)

Phase 1 IP3 SPU Power Ascension Testing

System/Component	Modification Description	Test
Radiation Measurement	Power increase to 100% power level	2 - Monitor and adjust N-16 main steam line radiation monitors. 1 - Perform plant radiation surveys post-power escalation to Phase 1 power level.
Low Pressure Turbine	Rotor blade upgrade	1 - Vibration monitoring and harmonic vibration speed determination and turbine differential expansion monitoring. 2 - Demonstration of thermal performance improvements and generator increase.
MTG Isolated Phase Bus Duct Cooling	Upgrade cooling & air flow fans	1 - Post-modification testing. 2 - Perform high pot of flex links, insulators 3 - Monitor cooling performance. Engineering evaluate deviations prior to power ascension approval. 4 - Perform hot spot survey on ducts and evaluate.

Table 10-3

Phase 1 IP3 SPU Power Ascension Tests vs. Power Levels

Test/Modification	Test Description	Rated Thermal Power % 3216 MWt (Allowance +/-.5%)					
		Prior to Startup	90	93.4	96.8 Pre-SPU 100%	98.4.	100
Main Turbine	Table 10-1	2					3
Turbine Inlet Steam Pressure	Table 10-1	1	2		2	2	2
Moisture Separator Reheaters	Table 10-1	1	2 3		2 3	2 3	2 3
Heater Drain System	Table 10-1	1	1 3 4		2 3 4		2 3 4
BOP sys. MS / EST / RST / C&FW / SWS	Table 10-1	1	2 4		2 4 5 6 7	2 4 5 6 7	2 3 5 6 7
MTG Isolated Phase Bus Duct cooling	Table 10-1	1 3 4			2	2	1 2 4
Main Transformer Monitoring	Table 10-1	2			1 3		1 3
RPS/ESFAS Setpoints	Table 10-1	1	1		1		1
Control System Setpoints	Table 10-1	1	1	1	1	1	1
Process Computer	Table 10-1	1					1
Radiation Measurement	Table 10-1						1

11.0 ENVIRONMENTAL IMPACTS

11.1 Introduction

The environmental issues associated with the issuance of an operating license for Indian Point Unit 3 (IP3) were originally evaluated in the *IP3 Final Environmental Statement* (FES) (Volume 1, page I-1 Section I) (Reference 1) and addressed plant operation up to a maximum calculated core power of 3216 MWt. The Atomic Energy Agency (AEC), the predecessor of the NRC, approved the FES in February 1975.

The Indian Point State Pollutant Discharge Elimination System (SPDES) restrictions on discharge temperatures and discharge flow rates for the station were evaluated along with the flow limits set forth in IP3 Consent Order.

11.2 Input Parameters and Assumptions

The IP3 FES that was approved by the AEC in February 1975 for a maximum calculated core power of 3216 MWt envelops the SPU condition.

The Indian Point SPDES restrictions on discharge temperatures and discharge flow rates for the station were used in the stretch power uprate (SPU) evaluation along with the flow limits set forth in the IP3 Consent Order.

The SPU evaluation assumes the existing Circulating Water Systém (CWS) pumps are not modified and continue to operate at the same flow rates. Since the CWS inlet temperatures from the Hudson River are not affected by the SPU, circulating flow is unchanged, and main condenser duty and exhaust flows will increase, the CWS discharge temperature to the Hudson River will increase.

Heat load increases due to SPU in the normal and emergency Service Water System (SWS) will result in an increase in the SWS discharge temperature to the Hudson River.

11.3 Description of Analysis and Evaluations

IP3 operation at the SPU core power level of 3216 MWt will increase the exhaust steam flow and duty of the main condenser and, therefore, increase the heat load rejected by the CWS and discharge temperature to the Hudson River. CWS flows were verified to be within the original design basis.

Heat load increases due to the SPU in the normal and emergency SWS will result in an increase in the original SWS discharge temperature to the Hudson River. SWS flows were verified to be within the design basis.

11.4 Acceptance Criteria

The environmental impacts associated with the proposed changes are acceptable when they are within the existing regulatory release permits.

11.5 Design Criteria

Design criteria are not applicable to the Environmental Impact Statement.

11.6 Results and Conclusions

Increased heat rejection to the CWS and SWS is expected to result in a nominal calculated increase in discharge temperature to the river. This temperature increase falls within the applicable SPDES permit thermal limits for IP3.

11.7 References

1. *Indian Point Unit 3 Final Evaluation Statement*, February 1975.